ATLANTIC POWER CORP
Form 10-K
February 29, 2012

Use these links to rapidly review the document
TABLE OF CONTENTS

Table of Contents

# 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, 2011**

**OR**

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

**For the transition period from to**
**Commission file number 001-34691**

# ATLANTIC POWER CORPORATION
(Exact Name of Registrant as Specified in its Charter)

| | |
|---|---|
| **British Columbia, Canada** | **55-0886410** |
| (State of Incorporation) | (I.R.S. Employer Identification No.) |
| **200 Clarendon St, Floor 25** | |
| **Boston, MA** | **02116** |
| (Address of Principal Executive Offices) | (Zip Code) |

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

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

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

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

Indicate by check mark if the registrant is a well-known seasoned issuer, as defined in Rule 405 of the Securities Act. Yes 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 ý | Accelerated Filer o | 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 30, 2011, the aggregate market value of the voting and nonvoting common equity held by non-affiliates of the registrant was $1.0 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 24, 2012, 113,526,182 of the registrant's Common Shares were outstanding.

**DOCUMENTS INCORPORATED BY REFERENCE**

Portions of the registrant's definitive Proxy Statement for its 2012 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.

Table of Contents

**TABLE OF CONTENTS**



*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.*

Table of Contents

## PART I

## FORWARD-LOOKING INFORMATION

*This report contains, in addition to historical information, "forward- looking" statements, as defined in the Private Securities Litigation Reform Act of 1995, that are based on our current expectations, estimates and projections about future events and financial trends affecting the financial condition and operations of our business. Forward-looking statements can be identified by the use of words such as "may," "will," "should," "could," "believe," "anticipate," "expect," "estimate," "plan," or other comparable terminology. Forward-looking statements are inherently subject to risks and uncertainties, many of which we cannot predict with accuracy and some of which we might not even anticipate. Although we believe that the expectations, estimates and projections reflected in such forward-looking statements are based on reasonable assumptions at the time made, we can give no assurance that these expectations, estimates and projections will be achieved. Future events and actual results may differ materially from those discussed in the forward-looking statements. Factors that could cause, or contribute to such differences include, without limitation, the factors described under Item 1A "Risk Factors." In view of these uncertainties, investors are cautioned not to place undue reliance on these forward-looking statements. Except as required by applicable law, we assume no obligation to update or revise publicly any forward-looking statements, whether as a result of new information, future events or otherwise.*

Table of Contents

## ITEM 1. BUSINESS

### OVERVIEW

Atlantic Power Corporation owns and operates a diverse fleet of power generation and infrastructure assets in the United States and Canada. Our power generation projects sell electricity to utilities and large industrial customers under long-term power purchase agreements, which seek to minimize exposure to changes in commodity prices. Our power generation projects in operation have an aggregate gross electric generation capacity of approximately 3,397 megawatts (or "MW") in which our ownership interest is approximately 2,140 MW. Our current portfolio consists of interests in 31 operational power generation projects across 11 states in the United States and two provinces in Canada, plus a 53 MW biomass project under construction in Georgia and a 500-kilovolt 84-mile electric transmission line located in California. We also own a majority interest in Rollcast Energy, a biomass power project developer and a 14.3% common equity interest in Primary Energy Recycling Holdings LLC ("PERH"). Twenty-two of our projects are wholly-owned subsidiaries.

The following map shows the location of our currently-owned projects, including joint venture interests, across the United States and Canada:

Table of Contents

| | Project Name | Location | Fuel Type | Total MW | Ownership Interest | Net MW |
|---|---|---|---|---|---|---|
| 1 | Auburndale | Auburndale FL | Natural Gas | 155 | 100% | 155 |
| 2 | Badger Creek | Bakersfield CA | Natural Gas | 46 | 50% | 23 |
| 3 | Cadillac | Cadillac MI | Biomass | 40 | 100% | 40 |
| 4 | Calstock | Hearst ON | Biomass | 35 | 100% | 35 |
| 5 | Chambers | Carney's Point NJ | Coal | 263 | 40% | 105 |
| 6 | Curtis Palmer | Corinth NY | Hydro | 60 | 100% | 60 |
| 7 | Delta Person | Albuquerque NM | Natural Gas | 132 | 40% | 53 |
| 8 | Frederickson | Tacoma WA | Natural Gas | 250 | 50% | 125 |
| 9 | Greeley | Greeley CO | Natural Gas | 72 | 100% | 72 |
| 10 | Gregory | Corpus Cristi TX | Natural Gas | 400 | 17% | 68 |
| 11 | Idaho Wind | Twin Falls ID | Wind | 183 | 28% | 50 |
| 12 | Kapuskasing | Kapuskasing ON | Natural Gas | 40 | 100% | 40 |
| 13 | Kenilworth | Kenilworth NJ | Natural Gas | 30 | 100% | 30 |
| 14 | Koma Kulshan | Concrete WA | Hydro | 13 | 50% | 6 |
| 15 | Lake | Umatilla FL | Natural Gas | 121 | 100% | 121 |
| 16 | Mamquam | Squamish BC | Hydro | 50 | 100% | 50 |
| 17 | Manchief | Brush CO | Natural Gas | 300 | 100% | 300 |
| 18 | Moresby Lake | Moresby Island BC | Hydro | 6 | 100% | 6 |

| | | | | | | |
|---|---|---|---|---|---|---|
| 19 | Morris | Morris IL | Natural Gas | 177 | 100% | 177 |
| 20 | Naval Station | San Diego CA | Natural Gas | 47 | 100% | 47 |
| 21 | Naval Training Ctr | San Diego CA | Natural Gas | 25 | 100% | 25 |
| 22 | Nipigon | Nipigon ON | Natural Gas | 40 | 100% | 40 |
| 23 | North Bay | North Bay ON | Natural Gas | 40 | 100% | 40 |
| 24 | North Island | San Diego CA | Natural Gas | 40 | 100% | 40 |
| 25 | Orlando | Orlando FL | Natural Gas | 129 | 50% | 65 |
| 26 | Oxnard | Oxnard CA | Natural Gas | 49 | 100% | 49 |
| 27 | Pasco | Tampa FL | Natural Gas | 121 | 100% | 121 |
| 28 | Path 15 | California | Transmission | NA | 100% | NA |
| 29 | PERH | Illinois | NA | NA | 14% | NA |
| 30 | Piedmont | Barnsville GA | Biomass | 53 | 98% | 53 |
| 31 | Rockland | American Falls ID | Wind | 80 | 30% | 24 |
| 32 | Selkirk | Bethlehem NY | Natural Gas | 345 | 18% | 64 |
| 33 | Tunis | Tunis ON | Natural Gas | 43 | 100% | 43 |
| 34 | Williams Lake | Williams Lake BC | Biomass | 66 | 100% | 66 |

Table of Contents

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

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

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

We directly operate and maintain more than half of our power generation fleet. We also partner with recognized leaders in the independent power industry to operate and maintain our other projects, including Caithness Energy, LLC ("Caithness"), Colorado Energy Management ("CEM"), Power Plant Management Services ("PPMS"), Delta Power Services ("DPS") and the Western Area Power Administration ("Western"). 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 IPO on the Toronto Exchange 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. Until December 31, 2009, we were externally managed under an agreement with Atlantic Power Management, LLC, an affiliate of ArcLight. We agreed to pay ArcLight an aggregate of $15 million to terminate its management agreement with us, satisfied by a payment of $6 million on the termination date of December 31, 2009, and additional payments of $5 million, $3 million and $1 million on the respective first, second and third anniversaries of the termination date. In connection with the termination of the management agreement, we hired all of the then-current employees of Atlantic Power Management and entered into employment agreements with its three officers.

At the time of our initial public offering, our publicly traded security was an Income Participating Security ("IPS"), each of which was comprised of one common share and a subordinated note. In

Table of Contents

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

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

As part of our integration efforts surrounding our acquisition of the Partnership, we have fully integrated the accounting and administration of the Canadian plants from the previous Capital Power accounting group into our Chicago office. Additionally, we have reviewed our existing policies and procedures to incorporate the changes necessary for a larger, more complex organization.

Our registered office is located at 355 Burrard Street, Suite 1900, Vancouver, British Columbia V6C 2G8 Canada and our headquarters is located at 200 Clarendon Street, Floor 25, Boston, Massachusetts, 02116 USA. Our telephone number in Boston is (617) 977-2400 and the address of our website is www.atlanticpower.com. We make available, free of charge, on our website our Annual Report on Form 10-K, Quarterly Reports on Form 10-Q, Current Reports on Form 8-K and amendments to those reports filed or furnished pursuant to Section 13(a) or 15(d) of the 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.

**OUR COMPETITIVE STRENGTHS**

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

- ***Diversified projects.*** Our power generation projects have an aggregate gross electric generation capacity of approximately 3,397 MW, and our net ownership interest in these projects is approximately 2,140 MW. These projects are diversified by fuel type, electricity and steam customers, and project operators. The majority are located in the deregulated and more liquid electricity markets of California, the U.S. Mid-Atlantic and New York. We also have a power transmission project, known as the Path 15 project, that is regulated by the Federal Energy Regulatory Commission ("FERC"). Additionally, we have a 53.5 MW biomass project under construction in Georgia.

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

Table of Contents

***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 believe that each project's combination of PPAs, fuel supply agreements and/or commodity hedges help stabilize operating margins.

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

***Strong in-house operations team complemented by leading third-party operators.*** We operate and maintain 17 of our power generation projects, which represent 44% of our portfolio's generating capacity, and the remaining 14 generation projects are operated by third-parties, who are recognized leaders in the independent power business. Affiliates of Caithness, CEM and PPMS operate projects representing approximately 19%, 14% and 8%, respectively, of the net electric generation capacity of our power generation projects. No other operator is responsible for the operation of projects representing more than 3% of the net electric generation capacity of our power generation projects.

***Strong customer base.*** Our customers are generally large utilities and other parties with investment-grade credit ratings. The largest customers of our power generation projects, including projects recorded under the equity method of accounting, are Public Service Company of Colorado ("PSCo"), Progress Energy Florida, Inc. ("PEF") and Ontario Electricity Financial Corp. ("OEFC"), which purchase approximately 17%, 15% and 9%, respectively, of the net electric generation capacity of our projects. No other electric customer purchases more than 6% of the net electric generation capacity of our power generation projects.

## OUR OBJECTIVES AND BUSINESS STRATEGY

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

### Organic growth

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

- achievement of improved operating efficiencies, output, reliability and operation and maintenance costs through the upgrade or enhancement of existing equipment or plant configurations;

- optimization of commercial arrangements such as PPAs, fuel supply and transportation contracts, steam sales agreements, operations and maintenance agreements and hedge agreements; and

- expansion of existing projects.

Table of Contents

**Extending PPAs following their expiration**

PPAs in our portfolio have expiration dates ranging from 2012 to 2037. In each case, we plan for expirations by evaluating various options in the market. New arrangements may involve responses to utility solicitations for capacity and energy, direct negotiations with the original purchasing utility for PPA extensions, "reverse" request for proposals by the projects to likely bilateral counterparty arrangements with creditworthy energy trading firms for tolling agreements, full service PPAs or the use of derivatives to lock in value. 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.

**Acquisition and investment strategy**

We believe that new electricity generation projects will continue to be required in the United States and Canada as a result of growth in electricity demand, transmission constraints and the retirement of older generation projects due to obsolescence or environmental concerns. In addition, Renewable Portfolio Standards in over 31 states as well as renewables initiatives in several provinces have greatly facilitated attractive PPAs and financial returns for significant renewable project opportunities. While we are not Greenfield developers ourselves, we are teaming with experienced development companies to acquire pipelines of late stage development investment opportunities. There is also a very active secondary market for the purchase and sale of existing projects.

We intend to expand our operations by making accretive acquisitions with a focus on power generation, transmission and related facilities in the United States and Canada. We may also invest in other forms of energy-related projects, utility projects and infrastructure projects, as well as make additional investments in development stage projects or companies where the prospects for creating long-term predictable cash flows are attractive. In 2010, we purchased a 60% interest in Rollcast Energy ("Rollcast"), a biomass developer out of North Carolina with a pipeline of development projects, in which we have the option but not the obligation to invest capital. We continue to assess development companies with strong late-stage development projects, and believe that there are opportunities in the market to enter into joint ventures with strong development teams.

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.

**ASSET MANAGEMENT**

Our asset management strategy is to ensure that our projects receive appropriate preventative and corrective maintenance and incur capital expenditures, if required, to provide for their safety, efficiency, availability and longevity. We also proactively look for opportunities to optimize power, fuel supply and other agreements to deliver strong and predictable financial performance. In conjunction with our acquisition of the 18 Partnership assets, the personnel that operated and maintained the assets became employees of Atlantic Power. The staff at each of the facilities has extensive experience in managing, operating and maintaining the assets. Personnel at Capital Power Corporation regional offices that provided support in operations management, environmental health and safety, and human resources also joined Atlantic Power. In combination with the existing staff of Atlantic Power, we have a dedicated and experienced operations and commercial management organization that is well regarded in the energy industry.

For operations and maintenance services at the 14 projects in our portfolio which we do not operate, we partner with recognized leaders in the independent power business. Most of our third-party operated projects are managed by Caithness; CEM, PPMS', DPS and, in the case of Path 15, Western,

Table of Contents

a U.S. Federal power agency. On a case-by-case basis, these third-party operators may provide: (i) day-to-day project-level management, such as operations and maintenance and asset management activities; (ii) partnership level management tasks, such as insurance renewals and annual budgets; and (iii) partnership level management, such as acting as limited partner. In some cases these project managers or the project partnerships may subcontract with other firms experienced in project operations, such as General Electric, to provide for day-to-day plant operations. 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.

Caithness is one of the largest privately-held independent power producers in the United States. For over 25 years Caithness has been actively engaged in the development, acquisition and management of independent power facilities for its own account as well as in venture arrangements with other entities. Caithness operates our Auburndale, Lake and Pasco projects and provides other asset management services for our Orlando, Selkirk and Badger Creek projects.

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

Power Plant Management Services 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. Previously, Cogentrix provided services to these facilities. Western owns and maintains the Path 15 transmission line. Western transmits and delivers hydroelectric power and related services within a 15-state region of the central and western United States. They are one of four power marketing administrations within the U.S. Department of Energy whose role is to market and transmit electricity from multi-use water projects. Western's transmission system carries electricity from 57 power plants. Together, these plants have an operating capacity of approximately 8,785 MW.

**OUR ORGANIZATION AND SEGMENTS**

The following tables outline by segment our portfolio of power generating and transmission assets in operation and under construction as of February 24, 2012, including our interest in each facility. We believe our portfolio is well diversified in terms of electricity and steam buyers, fuel type, regulatory jurisdictions and regional power pools, thereby partially mitigating exposure to market, regulatory or environmental conditions specific to any single region.

As a result of the Partnership acquisition we revised our reportable business segments during the fourth quarter of 2011. The new operating segments are Northeast, Southeast, Northwest, Southwest and Un-allocated Corporate. Our financial results for the years ended December 31, 2010 and 2009 have been presented to reflect these changes in operating segments. We revised our segments to align with changes in management's resource allocation and assessment of performance. These changes reflect our current operating focus. The segment classified as Un-allocated Corporate includes activities that support the executive offices, capital structure and costs of being a public registrant. These costs are not allocated to the operating segments when determining segment profit or loss. Un-allocated Corporate also includes Rollcast, a 60% owned company, which develops, owns and operates renewable power plants that use wood or biomass fuel.

Table of Contents

The sections below provide descriptions of our projects by segment. See Note 19 to the Consolidated Financial Statements for information on revenue from external customers, Project Adjusted EBITDA (a non-GAAP measure) and total assets by segment.

***Northeast Segment***

| Project Name | Location (State) | Type | Total MW | Economic Interest[(1)] | Net MW[(2)] | Primary Electric Purchaser | Power Contract Expiry | Customer S&P Credit Rating |
|---|---|---|---|---|---|---|---|---|
| **Cadillac** | Michigan | Biomass | 40 | 100.00% | 40 | Consumers Energy | 2028 | BBB- |
| **Chambers** | New Jersey | Coal | 262 | 40.00% | 105 | ACE[(3)] | 2024 | BBB+ |
| **Kenilworth** | New Jersey | Natural Gas | 30 | 100.00% | 30 | Schering-Plough Corporation | 2012[(4)] | AA |
| **Curtis Palmer** | New York | Hydro | 60 | 100.00% | 60 | Niagara Mohawk Power Corporation | 2027 | A- |
| **Selkirk** | New York | Natural Gas | 345 | 17.70%[(5)] | 15 | Merchant | N/A | N/R |
| | | | | | 49 | Consolidated Edison | 2014 | A- |
| **Calstock** | Ontario | Biomass | 35 | 100.00% | 35 | OEFC | 2020 | AA- |
| **Kapuskasing** | Ontario | Natural Gas | 40 | 100.00% | 40 | OEFC | 2017 | AA- |
| **Nipigon** | Ontario | Natural Gas | 40 | 100.00% | 40 | OEFC | 2022[(6)] | AA- |
| **North Bay** | Ontario | Natural Gas | 40 | 100.00% | 40 | OEFC | 2017 | AA- |
| **Tunis** | Ontario | Natural Gas | 43 | 100.00% | 43 | OEFC | 2014 | AA- |

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

(2)

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

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

(4) Contract expires July 31, 2012. Contract extension negotiations are ongoing.

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

(6) Ten year contract extension from 2012 to 2022 conditioned upon obtaining replacement fuel agreement, bidding for which is underway.

*Cadillac*

The Cadillac project is a 39.6 MW biomass power generation facility located in north central Michigan approximately 200 miles north of Detroit. The facility, which achieved commercial operation in 1993, was acquired by Atlantic Power in December 2010, from ArcLight Energy Partners Fund II and Olympus Power, LLC.

Cadillac sells up to 34 MW of its capacity and energy under a PPA with Consumers Energy Company ("Consumers") which expires in 2028, with the remaining output sold into the spot market. In 2007, Cadillac entered into a Reduced Dispatch Agreement with Consumers under which the project shares in the benefit when Consumers reduces the dispatch level of the project to a specified minimum during periods in which Consumers can purchase replacement power in the wholesale market at a price that is less than Cadillac's variable cost of production.

Table of Contents

The project consumes approximately 360,000 tons per year of biomass fuel sourced under numerous short-term supply contracts from approximately 30 local suppliers. Cadillac is managed by Rollcast and has an operations and maintenance agreement with DPS.

Cadillac has non-recourse debt outstanding of $38.8 million at December 31, 2011, which fully amortizes through 2025. In addition there are notes in the aggregate amount of approximately $1.4 million with Beaver Michigan Associates, LP, a party involved in the early development of the project, due April 15, 2012. See "Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations Liquidity and Capital Resources Project-level debt" for additional details.

*Chambers*

The Chambers project is a 262 MW pulverized coal-fired cogeneration facility located at the E.I. du Pont Nemours and Company ("DuPont") Chambers Works chemical complex near Carney's Point, New Jersey. The project sells steam and electricity, and achieved commercial operation in 1994. We have a 40% ownership interest in the Chambers project, with the remainder owned by an affiliate of Energy Investors Funds.

Chambers sells electricity to ACE under two separate power purchase agreements: a "Base PPA" and a power sales agreement ("PSA"). Under the Base PPA, which expires in 2024, ACE has agreed to purchase 184 MW of capacity and has dispatch rights for energy of up to approximately 180 MW with a minimum dispatch level of 46 MW. Energy generated at Chambers in excess of amounts delivered to ACE under the Base PPA and to DuPont, is sold to ACE under the PSA. Under this agreement, energy that ACE does not find economically attractive at the Base PPA's energy rate, but which may be cost effective to sell into the spot market, may be self-scheduled by the project to capture additional profits. The PSA includes a provision under which Chambers shares a portion of the margin on electricity sales with ACE. The PSA originally expired in July 2010 and we entered into subsequent replacement agreements on an annual basis in 2010 and 2011. The current PSA will expire in December 2012.

Steam and electricity is sold to DuPont under an energy services agreement ("ESA") that expires in 2024. In December 2008, Chambers filed a lawsuit against DuPont for breach of the ESA related to unpaid amounts associated with disputed price change calculations for electricity. DuPont subsequently filed a counterclaim for an unspecified level of damages. In February 2011, Chambers received a favorable ruling from the court on its summary judgment motion as to liability. In November 2011, the suit went to trial and we are currently awaiting a decision from the court.

Chambers financed the construction of the project with a combination of term debt due 2014 and New Jersey Economic Development Authority bonds due 2021. Both debt facilities are nonrecourse to the Company. In February 2012 Chambers failed one of its debt covenants and subsequently received a waiver from the creditors on February 24, 2012. Our 40% share of the total debt outstanding at the Chambers project as of December 31, 2011 is $64.1 million. See "Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations Liquidity and Capital Resources Project-level debt" for additional details.

*Kenilworth*

The Kenilworth project is a 30MW dual-fuel natural gas-fired combined cycle cogeneration facility located in Kenilworth, New Jersey adjacent to a pharmaceutical research and manufacturing facility owned by subsidiary of Merck & Co. Inc. The facility also has the capability of burning No. 2 distillate fuel oil. We indirectly own 100% of the project. Kenilworth sells electricity and steam to the facility under an ESA that expires in July 2012. Under the ESA, the facility pays for electricity at an energy rate that escalates annually. Excess generation above the Schering load is sold into the spot market. The price of steam under the ESA is based on the delivered cost of fuel to Schering's auxiliary boilers.

Table of Contents

Schering is able to request long-term purchase strategies to minimize the monthly volatility of natural gas prices.

The natural gas supply is purchased from PPL Energy Plus LLC and is priced at monthly index prices similar to the rates used in calculating the steam price under the ESA. We are currently in negotiations with Schering regarding extension of the ESA.

*Curtis Palmer*

The 60 MW Curtis Palmer facility consists of two run-of-river hydroelectric generating facilities located on the Hudson River near Corinth, New York that commenced commercial operation in 1913 and were re-powered in 1986. We indirectly own 100% of the project. All power generated by the facility is sold to Niagara Mohawk Power Corporation ("Niagara") under a PPA that expires at the earlier of 2027 or the delivery to Niagara of a cumulative 10,000 GWh of electricity. The PPA sets out 11 different energy pricing blocks for electricity sold to Niagara, with the applicable rate to be paid at any given time being dependent upon the cumulative generation that has been delivered to Niagara. Over the remaining term of the PPA, the energy rate increases by $10/MWh with each additional 1,000 GWh of electricity delivered. Under certain circumstances, Niagara has the ability to relocate, rearrange, retire or abandon its transmission system which would potentially give rise to material future capital cost outlays by Curtis Palmer to maintain its interconnection.

As of December 31, 2011, the Curtis Palmer project has $190 million aggregate principal amount of 5.90% senior unsecured notes due July 2014. See "Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations  Liquidity and Capital Resources" for additional details.

*Selkirk*

The Selkirk project is a 345 MW dual-fuel, combined-cycle cogeneration plant located in the Town of Bethlehem in Albany County, New York, which commenced commercial operation in 1994. The project site is situated adjacent to a Saudi Arabia Basic Industries Corporation ("SABIC") plastics manufacturing plant, which also purchases steam from the project. Selkirk consists of two units: Unit I (79 MW), which currently sells electricity into the New York merchant market and Unit II (265 MW) which sells electricity to Consolidated Edison Company of New York, Inc. ("ConEd"). We own an approximate 18.5% interest in the Selkirk project. The other partners include affiliates of Energy Investors Funds, The McNair Group, and Osaka Gas Energy America Corporation.

Selkirk sells the output from Unit I into the New York merchant market, and the output of Unit II to ConEd under a PPA that expires in 2014, subject to a 10-year extension at the option of ConEd under certain conditions. The Unit II PPA provides for a capacity payment, a fuel payment, an operations and maintenance payment, and a payment for transmission costs from the project to ConEd. The capacity payment, a portion of the fuel payment, a portion of the operations and maintenance payment, and the transmission payment are paid on the basis of plant availability.

The project sells steam to the SABIC plant under an agreement that expires in 2014, under which SABIC is not charged for steam in an amount up to a specified level during each hour in which the SABIC plant is in production. For steam in excess of the specified amount, SABIC pays the project a variable price. SABIC is required to purchase the minimum thermal output necessary for Selkirk to maintain its QF status.

Selkirk purchases natural gas for Unit I at spot market prices under a contract with Coral Energy Canada Inc. expiring in 2012. Selkirk is in the process of engaging a third party to provide fuel management and procurement services post 2012. The gas supply arrangements for Unit II are with

Table of Contents

Imperial Oil Resources Limited, and EnCana Corporation and Canadian Forest Oil Limited, which expire in 2014.

The Selkirk project has 8.98% first mortgage bonds outstanding which are non-recourse to us and which fully amortize over the remaining term of the PPA . Our proportionate share of the mortgage bonds is $5.8 million as of December 31, 2011. See "Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations Liquidity and Capital Resources Project-level debt" for additional details.

*Calstock*

Calstock is a 35 MW generating facility that uses enhanced combined cycle generation and biomass to produce electricity. The plant is located near Hearst, Ontario, adjacent to a compressor station on the TransCanada Mainline and achieved commercial operation in 2000. We indirectly own 100% of the project and also provide operations and management services. Calstock utilizes a biomass boiler and a steam turbine, in conjunction with waste heat from the nearby TransCanada Mainline compressor station, to generate electricity.

Electrical output is sold to the OEFC under a PPA that expires in 2020. Calstock burns wood waste obtained under short-term contracts from three local sawmills: Tembec, Inc., Lecours Lumber Company Limited and Columbia Forest Products, Inc. Although the supply of wood waste and related transportation services are contracted, the suppliers have no obligation to provide fuel in the event they scale back or shut down operations. Pursuant to a Certificate of Approval ("CoA") from the Ministry of Environment, Calstock successfully completed a test burn of railroad rail ties in November 2009. The project has applied for a permanent CoA amendment from the Ministry of Environment, which if approved, would permit the burning of rail ties up to approximately 20% of the Calstock facility's fuel requirement.

Under a long-term waste heat agreement with TransCanada, Calstock is provided on an as-available basis, all of the waste heat generated by the gas turbine compressors located adjacent to the project. In the event waste heat output is reduced at the compressor station arising from any cause, TransCanada's obligation to deliver waste heat is reduced accordingly.

*Kapuskasing*

The Kapuskasing facility is a gas-fired 40 MW facility that uses enhanced combined cycle generation to produce electricity. The facility is located near Kapuskasing, Ontario adjacent to a compressor station on the TransCanada Mainline and achieved commercial operation in 1997. We indirectly own 100% of the project and also provide operations and management services. The facility utilizes a gas turbine driven generator and a steam turbine, in conjunction with waste heat from the nearby TransCanada Mainline gas transmission compressor station to generate electricity.

Electrical output is sold to the OEFC under a PPA that expires in 2017. Natural gas is procured under a long-term gas supply agreement with TransCanada Power Marketing expiring in 2017. The gas supply is transported to the plant under a firm transportation agreement with TransCanada Pipelines expiring in 2016. Under a long-term waste heat agreement with TransCanada, Kapuskasing is provided on an as-available basis, all of the waste heat generated by the gas turbine compressors located adjacent to the project. In the event waste heat output is reduced at the compressor station arising from any cause, TransCanada's obligation to deliver waste heat is reduced accordingly.

*Nipigon*

The Nipigon facility is a gas-fired 40 MW plant that uses enhanced combined cycle generation to produce electricity. Nipigon is located in Nipigon, Ontario, adjacent to a compressor station on the

Table of Contents

TransCanada Mainline and achieved commercial operation in 1992. We indirectly own 100% of the project and also provide operations and management services. Nipigon utilizes a gas-fired combustion turbine and a steam turbine, in conjunction with waste heat from the nearby TransCanada compressor station, to generate electricity.

Electrical output is sold to the OEFC under a PPA that expires in 2012, but extends automatically to 2022 upon satisfying certain conditions related to a replacement gas supply. Natural gas is procured under long-term gas supply agreements with NAL Oil and Gas Trust and Petrobank Energy that expire in 2012. We are currently in the process of obtaining a replacement long-term gas supply agreement for Nipigon that meets the extension requirements under the PPA. Nipigon's fuel supply is transported under a long-haul agreement with TransCanada which transports gas from Nipigon's suppliers in Alberta to the plant. The fuel transportation agreement expires in 2012 and will be renewed as part of the replacement gas supply agreement. Under a long-term waste heat agreement with TransCanada, Nipigon is provided on an as-available basis all of the waste heat generated by the gas turbine compressors located adjacent to the project. In the event waste heat output is reduced at the compressor station arising from any cause, TransCanada's obligation to deliver waste heat is reduced accordingly.

*North Bay*

North Bay is a gas-fired 40 MW facility that uses enhanced combined cycle cogeneration to produce electricity. We indirectly own 100% of the project and also provide operations and management services. North Bay is located in North Bay, Ontario adjacent to a compressor station on the TransCanada Mainline and achieved commercial operation in 1989. North Bay utilizes a gas-fired combustion turbine and a steam turbine, in conjunction with waste heat from the nearby TransCanada compressor station, to generate electricity.

Electrical output is sold to the OEFC under a PPA that expires in 2017. Natural gas is procured under a long-term gas supply agreement with TransCanada Power Marketing expiring in 2017. Gas is transported to the plant under a transportation agreement with TransCanada that expires in 2016. Under a long-term waste heat agreement with TransCanada, North Bay is provided, on an as-available basis, all of the waste heat generated by the gas turbine compressors located adjacent to the project. In the event waste heat output is reduced at the compressor station arising from any cause, TransCanada's obligation to deliver waste heat is reduced accordingly.

*Tunis*

Tunis is a 43 MW facility that uses enhanced combined cycle cogeneration to produce electricity. We indirectly own 100% of the project and also provide operations and management services. The facility is located in Tunis, Ontario adjacent to a compressor station on the TransCanada Mainline and achieved commercial operation in 1995. Tunis utilizes a gas-fired combustion turbine and a steam turbine, in conjunction with waste heat from the nearby TransCanada compressor station, to generate electricity.

Electrical output is sold to the OEFC under a PPA that expires in 2014. Natural gas is procured under a combination of spot purchases and short-term contracts. Tunis has gas transportation agreements with TransCanada, expiring in 2014, to ship gas to the plant. Under a long-term waste heat agreement with TransCanada, Tunis is provided, on an as-available basis, all of the waste heat generated by the gas turbine compressors located adjacent to the project. In the event waste heat output is reduced at the compressor station arising from any cause, TransCanada's obligation to deliver waste heat is reduced accordingly.

Table of Contents

***Southeast Segment***

| Project Name | Location (State) | Type | Total MW | Economic Interest | Net MW | Primary Electric Purchaser | Power Contract Expiry | Customer S&P Credit Rating |
|---|---|---|---|---|---|---|---|---|
| **Auburndale** | Florida | Natural Gas | 155 | 100.00% | 155 | Progress Energy Florida | 2013 | BBB+ |
| **Lake** | Florida | Natural Gas | 121 | 100.00% | 121 | Progress Energy Florida | 2013 | BBB+ |
| **Pasco** | Florida | Natural Gas | 121 | 100.00% | 121 | Tampa Electric Co. | 2018 | BBB+ |
| **Orlando** | Florida | Natural Gas | 129 | 50.00% | 46 | Progress Energy Florida | 2023 | BBB+ |
| | | | | | 19 | Reedy Creek Improvement District | 2013[1] | AA-[2] |
| **Piedmont**[3] | Georgia | Biomass | 54 | 98.00% | 53 | Georgia Power | 2032 | A |

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

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

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

*Auburndale*

The Auburndale project is a 155 MW dual fuel (natural gas and oil), combined-cycle, cogeneration plant located in Pope County, Florida, which commenced commercial operations in 1994. We indirectly own 100% of the Auburndale project, which was acquired in 2008 from ArcLight Energy Partners Fund I, L.P. and Calpine Corporation. The capacity and energy from the project is sold to PEF under three PPAs expiring at the end of 2013. Steam is sold to Florida Distillers Company and the Cutrale Citrus Juices USA. The Florida Distillers steam agreement is renewed annually and the Cutrale Citrus Juices agreement expires in 2013. Auburndale is operated and maintained by an affiliate of Caithness. The project also has a maintenance agreement in place with Siemens Energy, Inc. for the long-term supply of certain parts, repair services and outage services related to the gas turbine, which expires in 2013.

Each of Auburndale's PPAs expires at the end of 2013. Under the largest of the PPAs, Auburndale sells 114 MW of capacity and energy to PEF. In addition, 17 MW of capacity is sold under two identical 8.5 MW agreements with PEF. Electricity revenues from the three PPAs consist of capacity payments based on a fixed schedule of prices and energy payments. The capacity payments are dependent on Auburndale maintaining a minimum on peak capacity factor. Auburndale entered into an agreement with Tampa Electric Company ("TECO") to transmit electric energy from the project to PEF. Under the agreement, which expires in 2024, Auburndale's cost for these services is based on a contractual formula derived from TECO's cost of providing such services.

Auburndale obtains the majority of its natural gas requirements through a gas supply agreement with El Paso Merchant Energy, LP, that expires in June 2012. We are in the process of obtaining a replacement gas supply that will extend to the expiry of the PPA in 2013.

As of December 31, 2011, the Auburndale project has an $11.9 million 5.10% term loan which is due in 2013. See "Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations Liquidity and Capital Resources Project-level debt" for additional details.

*Lake*

Lake is a 121 MW dual-fuel, combined-cycle, cogeneration facility located in Umatilla, Florida, that began commercial operation in 1993. We indirectly own 100% of the Lake project. Capacity and electric energy is sold to PEF under a PPA expiring in July 2013. Steam is sold to Citrus World, Inc.

Table of Contents

for use at its adjacent citrus processing facility, and is also used to make distilled water in the projects distillation units that is sold to various parties. The Lake facility does not have any debt outstanding.

Revenues under the PPA consist of a fixed capacity payment and an energy payment. The capacity payment is based on Lake maintaining a specified capacity factor during on-peak hours (11 hours daily). Energy payments are comprised of several components including a fuel component based on the cost of coal consumed at two PEF owned coal-fired generating stations and a component intended to recover operations and maintenance costs. The project sells steam to Citrus World under an agreement that expires in 2013.

Natural gas requirements for the facility are provided by Iberdrola Renewables, Inc. and TECO Gas Services, Inc. under contracts that expire in 2013. Natural gas is transported to the project from supply points in Texas, Louisiana and Mississippi under contracts with Peoples Gas System, Inc.

Lake is operated and maintained by an affiliate of Caithness. The facility also has a long-term services agreement and a lease engine agreement in place with General Electric ("GE") to provide for planned and unplanned maintenance on Lake's two gas turbines, and to provide temporary replacement gas turbines when Lake's turbines are removed for major maintenance.

*Pasco*

The Pasco project is a 121 MW dual-fuel, combined-cycle, cogeneration facility located in Dade City, Florida which began commercial operation in 1993. Upon the expiration of Pasco's original PPA with PEF in 2008, the facility entered into a replacement tolling agreement with TECO that expires in 2018. Under the terms of the tolling agreement, TECO is responsible for the fuel supply and is financially responsible for fuel transportation to Pasco. We indirectly own 100% of the Pasco project.

Revenues under the tolling agreement with TECO consist of capacity payments, startup charges, variable payments based on the amount of electricity generated, and heat rate bonus payments based on the actual efficiency of the plant versus a contractual efficiency.

Pasco is operated and maintained by an affiliate of Caithness. The project also has a long-term services agreement and a lease engine agreement in place with GE.

*Orlando*

The Orlando project, a 129 MW natural gas-fired, combined-cycle, cogeneration facility located near Orlando Florida, commenced commercial operation in 1993. We indirectly own a 50% interest in the project and Northern Star Generation, LLC ("Northern Star") owns the remaining 50% interest. Orlando sells all of its electricity to PEF and Reedy Creek Improvement District ("Reedy Creek") under long-term PPAs. Orlando also sells chilled water produced using steam from the project to a subsidiary of Air Products and Chemicals.

Capacity and energy up to 79.2 MW is sold to PEF under a PPA that expires in 2023, under which Orlando receives a monthly capacity payment based on achieving a specified on-peak capacity factor, and an energy payment based on the total amount of electric energy delivered to PEF. In 2009, PEF provided notice to Orlando that the committed capacity under its PPA would be increased to 115 MW upon expiration of the Reedy Creek PPA in 2013, upon meeting certain criteria. Capacity and energy is also sold to Reedy Creek, a municipal district serving the Walt Disney World complex, under a PPA that expires in 2013. Orlando receives a monthly capacity payment based on the actual average on-peak capacity factor of the facility and a monthly energy payment based on the total amount of electric energy delivered to Reedy Creek. In 2009, Orlando executed an agreement with Rainbow Energy Marketing Corporation ("Rainbow") to market up to 15 MW of energy at spot market rates subject to the profitability of such sales. The agreement with Rainbow can be terminated by either party upon 30 days notice.

Table of Contents

Under an agreement with a subsidiary of Air Products and Chemicals, Orlando supplies chilled water produced using steam from the project to its cryogenic air separation facility. Due to reduced demand for chilled water at the Air Products and Chemicals facility, Orlando procured and installed water distiller units in 2009 and entered into contracts to provide the distilled water to unaffiliated third parties to ensure maintenance of its QF status.

Natural gas is purchased from an affiliate of Northern Star under an agreement that expires in 2013. Other affiliates of Northern Star entered into agreements with Florida Gas Transmission for the delivery of natural gas to Orlando. The project is operated and maintained by an affiliate of Northern Star under an operations and maintenance services agreement that expires in 2023. In 1997, Orlando also entered into a long-term maintenance agreement with Alstom Power Inc. for the long-term supply of hot gas path turbine parts.

*Piedmont*

The Piedmont project is a 53.5 MW biomass-fired, electric generating facility under construction in Barnesville, Georgia, approximately 60 miles Southeast of Atlanta. The project was developed by our 60% owned subsidiary Rollcast. We have a 98% ownership interest in Piedmont.

Piedmont will sell 100% of its output to Georgia Power Company under a 20-year PPA and has executed two long-term biomass fuel supply contracts under pricing terms that largely track the energy payment under the PPA. Zachary Industrial ("ZHI") is constructing the facility under a turn-key engineering procurement and construction contract. Notice to proceed was authorized in October 2010 and commercial operation is expected in late 2012. Total project costs of approximately $207 million were financed in part with an $82 million construction loan, which will convert to a five-year term loan upon commercial operation, a $51 million bridge loan and approximately $75 million of equity contributed by the Company. The bridge loan will be repaid from the proceeds of a federal stimulus grant, which is expected to be received two months after achieving commercial operation. We expect to refinance the term loan over a longer period.

Operations and management services will be provided under a five-year agreement with DPS. DPS will be paid its actual direct operating costs plus an annual fee. Piedmont has also executed a management services agreement with Rollcast for the provision of administrative and asset management services.

***Northwest Segment***

| **Project Name** | **Location (State)** | **Type** | **Total MW** | **Economic Interest** | **Net MW** | **Primary Electric Purchaser** | **Power Contract Expiry** | **Customer S&P Credit Rating** |
|---|---|---|---|---|---|---|---|---|
| **Mamquam** | British Columbia | Hydro | 50 | 100.00% | 50 | British Columbia Hydro and Power Authority | 2027 | AAA |
| **Moresby Lake** | British Columbia | Hydro | 6 | 100.00% | 6 | British Columbia Hydro and Power Authority | 2022 | AAA |
| **Williams Lake** | British Columbia | Biomass | 66 | 100.00% | 66 | British Columbia Hydro and Power Authority | 2018 | AAA |
| **Idaho Wind** | Idaho | Wind | 183 | 27.56% | 50 | Idaho Power Co. | 2030 | BBB |
| **Rockland** | Idaho | Wind | 80 | 30.00% | 24 | Idaho Power Co. | 2036 | BBB |

| | | | | | | | | |
|---|---|---|---|---|---|---|---|---|
| **Frederickson** | Washington | Natural Gas | 250 | 50.15% | 125 | 3 Public Utility Districts | 2022 | A to A+ |
| **Koma Kulshan** | Washington | Hydro | 13 | 49.80% | 6 | Puget Sound Energy | 2037 | BBB |

Table of Contents

*Mamquam*

Mamquam station is a wholly-owned 50 MW run-of-river hydroelectric generating plant located on the Mamquam River in British Columbia. The plant achieved commercial operation in 1996. We indirectly own 100% of Mamquam and also provide operations and management services. All of the output of the station is sold to British Columbia Hydro and Power Authority ("BC Hydro") under a long-term PPA which expires in 2027. BC Hydro has the option, exercisable in 2021 and every five years thereafter, to either purchase the Mamquam facility or extend the PPA. The energy rate under the PPA consists of a fixed energy component, an operations and maintenance component (adjusted annually for inflation), and a reimbursable cost component which covers expenses such as property taxes, water and land-use fees, as well as insurance premiums.

*Moresby Lake*

Moresby Lake is a 6 MW reservoir-based, hydroelectric generating station located on the island of Haida Gwaii off the coast of northern British Columbia. The project achieved commercial operation in 1990. We indirectly own 100% of Moresby Lake and also provide operations and management services. Substantially all of the output of the facility is sold to BC Hydro under a long-term PPA expiring in 2022. The energy rate payable by BC Hydro consists of a fixed energy rate adjusted annually for inflation. Approximately 1% of the station's generation is sold to NAV Canada and the Department of Fisheries and Oceans (Canada) under long-term PPAs.

*Williams Lake*

The Williams Lake power plant is a wholly-owned 66 MW biomass fired generating facility located in Williams Lake, British Columbia, that achieved commercial operation in 1993. Power is sold to BC Hydro under a PPA with the initial term expiring in 2018. BC Hydro has an option to extend the agreement by up to 10 years, on the basis of two five-year term extensions. The Williams Lake plant is operated and maintained by one of our affiliates.

The PPA contains two pricing tranches: a firm energy tranche, representing approximately 82% of the total energy produced; and a surplus energy tranche, representing approximately 18% of total energy produced. The firm energy tranche pricing consists of a fixed energy component, an operations and maintenance component (adjusted annually for average weekly earnings in British Columbia), and a reimbursable cost component. The surplus energy tranche pricing is adjusted annually for changes in the Dow Jones California Oregon Border index. However, surplus energy can be sold to a third party if a higher price is available. In 2010, the surplus energy was sold to a third party at a higher price than under the PPA. In 2011, the price of surplus energy was determined through negotiations with BC Hydro at a rate higher than what the PPA would have provided.

Williams Lake is fueled by locally purchased wood waste under six fuel supply agreements: five expiring in 2018 and one expiring in 2014. The facility also obtains wood waste from several periodic suppliers on an as-available and as-needed basis. The PPA with BC Hydro provides for the recovery of approximately 82% of the cost of fuel, thereby largely protecting the plant from the impact of increased fuel costs.

*Idaho Wind*

The Idaho Wind project is a 183 MW wind power project comprised of 11 wind farms located near Twin Falls, Idaho. Construction of the project began in June 2010 and it commenced commercial operation in January 2011. The Idaho Wind project is owned by Idaho Wind Partners 1, LLC ("Idaho Wind"), in which we own a 27.6% interest. We acquired our ownership interest in July 2010. The other owners are affiliates of GE Energy Financial Services, Reunion Power, and Exergy Development Group, the original project developer. Electricity is sold to Idaho Power Company under 11 PPAs expiring in 2030.

Table of Contents

The project was financed in part by a consortium of lenders with a $221 million project-level credit facility that closed in October 2010. The credit facility is composed of two tranches, which are a $139 million construction loan that converted to a 17-year term loan following commercial operation, and an $83 million cash grant facility that was repaid with federal grant proceeds after completion of construction in early 2011. The remaining costs of the project of approximately $200 million were funded with a combination of owners' equity and member loans from affiliates of Atlantic Power and GE Energy Financial Services. The member loans were fully repaid in 2011. Idaho Wind's project financing includes credit support for the facility's obligations under the PPAs in the form of approximately $20 million of letters of credit.

Under the terms of the PPAs, Idaho Power purchases all of the electricity at fixed prices. The price paid for electricity can be reduced in the event the wind farms do not maintain a minimum level of availability or underperform relative to monthly nominations under the PPA.

An operations support agreement is in place with GE that provides for ongoing monitoring of the performance of the wind turbines as well as planned and unplanned maintenance. Idaho Wind also has a balance of plant maintenance contract with Caribou Construction to maintain the projects' substations and other equipment not associated with the wind turbines. Day-to-day operations and maintenance is provided by an affiliate of Reunion Power under a management services agreement.

Our proportionate share of the Idaho Wind project's non-recourse debt is $50.9 million as of December 31, 2011, which fully amortizes by and has a final maturity in 2027. See "Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations Liquidity and Capital Resources Project-level debt" for additional details.

*Rockland*

The Rockland Wind Project LLC ("Rockland") is an 80 MW wind power generating facility located near American Falls, Idaho, which commenced commercial operation in December 2011. We acquired a 30% ownership interest in Rockland in December 2011. Rockland's other owners include Ridgeline Energy, LLC, the project developer, and an affiliate of Diamond Generating Corporation. Electricity is sold to Idaho Power Company under a 25-year fixed-price PPA expiring in 2036.

The Rockland project utilizes wind turbines manufactured by Vestas Wind Systems ("Vestas"), which also provides an availability guarantee. Vestas provides long-term turbine operations and maintenance services to the project under a 10-year service agreement. enXco, an established provider of renewable energy development and operations and management services, is under contract to provide administrative services, plant maintenance and maintenance of the transmission lines and collection systems.

The project was financed with a bank facility in March 2011 with Bank of Tokyo Mitsubishi, Sumitomo and Mizuho. The facility consisted of an $87.0 million construction loan, a $45.0 million 1603 cash grant bridge loan and a $5.0 million letter of credit facility. At term conversion, the construction loan converts to an $87.0 million, 15-year term loan. The term loan is fully swapped for the life of the loan at a LIBOR equivalent of 4.02%. Debt service is paid semi-annually as are distributions.

Our proportionate share of the Rockland project's debt is $39.3 million as of December 31, 2011, which is due 2031.

*Frederickson*

The Frederickson facility is a 250 MW combined cycle gas-fired generating facility that commenced commercial operation in 2002. The facility, located near Tacoma, Washington, also has 20 MW of duct firing capability. We indirectly own a 50.15% interest in the project. Our share of the output of the

Table of Contents

facility, approximately 125 MW, is sold to three different Washington State Public Utility Districts ("PUDs") under PPAs expiring in 2022. The Frederickson plant is operated and maintained by one of our affiliates.

Under each of the PPAs, Frederickson provides generating capacity and associated energy to each of the PUDs in exchange for a capacity charge, a fixed operations and maintenance charge, a variable operations and maintenance charge and a fuel charge. The PUDs supply their proportionate share of natural gas to Frederickson at a specific delivery point. Frederickson is responsible for obtaining firm transportation from such delivery point to the facility. The facility is responsible for any fixed and variable cost increases above those recoverable under the PPAs, other than costs resulting from the effects of material changes to environmental and tax laws. The remainder of the ownership interest in Frederickson, approximately 49.85%, is held by Puget Sound Energy, Inc. ("PSE"). The portion of Frederickson's output allocable to PSE under its ownership interest is used by PSE to meet the needs of a portion of its electrical customers.

*Koma Kulshan*

The Koma Kulshan project is a 13 MW run-of-river hydroelectric generating facility located on the slopes of Mount Baker, approximately 80 miles north of Seattle, Washington. Koma Kulshan commenced commercial operations in 1990. The project has a PPA with PSE that expires in 2037. We have a 49.75% economic interest in Koma Kulshan. The other partners include Mt. Baker Corporation and Covanta Energy Corporation ("Covanta"). Operations and maintenance of the facility is performed under an agreement with Covanta, which expires in 2012 and is renewed annually.

***Southwest Segment***

| Project Name | Location (State) | Type | Total MW | Economic Interest | Net MW | Primary Electric Purchaser | Power Contract Expiry | Customer S&P Credit Rating |
|---|---|---|---|---|---|---|---|---|
| **Badger Creek** | California | Natural Gas | 46 | 50.00% | 23 | Pacific Gas & Electric | 2013(1) | BBB+ |
| **Naval Station** | California | Natural Gas | 47 | 100.00% | 47 | San Diego Gas & Electric | 2019 | A |
| **Naval Training Center** | California | Natural Gas | 25 | 100.00% | 25 | San Diego Gas & Electric | 2019 | A |
| **North Island** | California | Natural Gas | 40 | 100.00% | 40 | San Diego Gas & Electric | 2019 | A |
| **Oxnard** | California | Natural Gas | 49 | 100.00% | 49 | Southern California Edison | 2020 | BBB+ |
| **Path 15** | California | Transmission | N/A | 100.00% | N/A | California Utilities via CAISO(2) | N/A(3) | BBB+ to A(4) |
| **Greeley** | Colorado | Natural Gas | 72 | 100.00% | 72 | Public Service Company of Colorado | 2013 | A- |
| **Manchief** | Colorado | Natural Gas | 300 | 100.00% | 300 | Public Service Company of Colorado | 2022 | A- |

| | | | | | | | | |
|---|---|---|---|---|---|---|---|---|
| **Morris** | Illinois | Natural Gas | 177 | 100.00% | 77 | Equistar Chemicals, LP | 2023 | BB- |
| | | | | | 100 | Merchant | | N/A |
| **Delta-Person** | New Mexico | Natural Gas | 132 | 40.00% | 53 | Public Service Company of New Mexico | 2020 | BB |
| **Gregory** | Texas | Natural Gas | 400 | 17.10% | 59 | Fortis Energy Marketing and Trading | 2013 | AA |
| | | | | | 9 | Sherwin Alumina | 2020 | N/R |
| **PERH**[(5)] | Illinois | | | 14.30% | | | | |

(1) Entered into a one-year interim agreement in February 2012.

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

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

Table of Contents

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

(5) On February 16, 2012, we entered into an agreement with Primary Energy Recycling Corporation ("PERC"), whereby PERC will purchase our 14.3% common ownership interests in PERH. Completion of the transaction is subject to PERC obtaining financing and is expected to occur in the second quarter of 2012.

*Badger Creek*

The Badger Creek facility is a 46 MW simple-cycle, gas-fired cogeneration facility that commenced commercial operation in 1991. We own a 50% interest in the project. A private equity fund managed by ArcLight owns the remaining 50% interest. The output of the facility is sold to PG&E under a PPA that expires in April 2013, at which time a transition PPA will become effective ("Transition PPA"). The Transition PPA expires in June 2015 and is pursuant to the "Qualifying Facility and Combined Heat and Power Program Settlement Agreement" ("Settlement Agreement") under a proceeding at the California Public Utilities Commission achieved in November 2011. The Settlement Agreement, among other QF facilities, California's major investor-owned utilities, and numerous consumer and independent power producer groups, resolves numerous outstanding QF disputes and provides for an orderly transition from the existing QF program in California to a new QF/Combined Heat and Power program.

Under the PPA and Transition PPA, Badger provides capacity and associated energy to PG&E in exchange for a capacity charge, and an energy charge based on defined heat rates. Gas is supplied by J.P. Morgan Ventures Energy Corporation. Consolidated Asset Management Services, an affiliate of ArcLight, provides administrative services and operations and maintenance services.

*Naval Station*

The Naval Station Facility is a wholly-owned 47 MW cogeneration facility that supplies steam to the US Navy's San Diego Naval Station located in San Diego, California. The facility began commercial operation in 1989 and is operated and maintained by an affiliate of the Company. The Naval Station plant supplies electricity to San Diego Gas & Electric Company ("SDG&E") pursuant to a long-term PPA, which expires in 2019. The steam agreement expires in 2018. Fuel is supplied by JP Morgan under a monthly indexed pricing agreement which links the gas price used in the PPA energy payments with similar components in the Navy steam contract to minimize the exposure to gas price volatility.

*Naval Training Center*

The Naval Training Center facility is a wholly-owned nominal 25 MW, dual-fuel cogeneration facility located at the U.S. Marine Corps Recruit Depot (and former Naval Training Center) in San Diego, California. The facility began commercial operation in 1989 and is operated and maintained by an affiliate of the Company.

The Naval Training Center facility supplies electricity to SDG&E pursuant to a long-term PPA, which expires in 2019. A portion of the facility's output is sold to SDG&E under a Standard Offer contract with an indefinite term. The Naval Training Center facility also sells steam to the U.S. Marine Corps under an agreement that expires in 2018. Fuel is supplied by J.P. Morgan under a monthly indexed pricing agreement that links the gas price used in the PPA energy payments with similar components in the Navy steam contract to minimize the exposure to gas price volatility.

*North Island*

The North Island facility is a wholly-owned 40 MW cogeneration facility that serves the US Navy's North Island Naval Air Station on Coronado Island located in San Diego, California. The facility began commercial operation in 1989 and is operated and maintained by an affiliate of the Company. The

Table of Contents

North Island plant supplies electricity to SDG&E pursuant to a long term PPA that expires in 2019. The facility also provides electricity and steam to the Navy for building heat and to service docked ships, and for the aircraft re-work facility. The steam agreement expires in 2018. Fuel is supplied by JP Morgan under a monthly indexed pricing agreement that links the gas price used in the PPA energy payments with similar components in the Navy steam contract to minimize the exposure to gas price volatility.

*Oxnard*

The Oxnard plant is a wholly-owned 49 MW peaker facility located in Oxnard, California, that achieved commercial operations in 1990. Electrical output from the facility is sold to Southern California Edison Company ("SCE") under a PPA expiring in 2020.

Oxnard uses steam in its absorption refrigeration plant to provide refrigeration services to Boskovich Farms, Inc. ("Boskovich") at no charge; thereby maintaining the facility's QF status. The original energy services agreement with Boskovich expired in 2005 and refrigeration services are currently being provided on a month-to-month agreement. Boskovich is an integrated vegetable and fruit grower, processor, and refrigerated/frozen food storage company.

*Path 15*

Path 15 consists of our ownership of 72% of the transmission system rights associated with the Path 15 transmission project, an 84-mile, 500-kilovolt transmission line built along an existing transmission corridor in central California. The Path 15 project commenced commercial operation in 2004 and facilitates the movement of power from the Pacific Northwest to southern California in the summer months and from generators in southern California to northern California in the winter months. The transmission system rights entitle us to receive an annual revenue requirement that is regulated by the FERC which established a 30-year regulatory life for the project. The annual revenue requirement is established in a triennial rate case proceeding before the FERC. Such a rate case proceeding is currently underway.

In February 2011, we filed our triennial rate application with the FERC to establish Path 15's revenue requirement for the 2011-2013 period. We engaged in a formal settlement process with FERC staff and three parties that challenged certain aspects of how Path 15 determined the rates in its filing. After exchanges of information and direct discussions, we concluded that a fair and equitable settlement between the parties was not achievable through the settlement process and therefore in September 2011, we ended settlement discussions and pursued resolution of the issues through the formal hearing process at FERC. This step was similarly taken in the prior rate case, which ultimately concluded in a settlement among the parties. We may engage the parties in informal settlement discussions during the hearing process. If a settlement can be reached with the parties, the hearing process will be terminated.

In September 2011, FERC appointed a presiding judge in Path 15's rate case hearing proceeding. Under the judge's order establishing the procedural schedule for the case, the discovery period was set for October 2011 through April 2012. The formal rate case hearing is scheduled to commence on May 1, 2012. The initial decision from the presiding judge will be due on or before August 16, 2012. The timing of FERC's issuance of its final decision in the rate case has no set schedule or time constraint, and final resolution of the rate case proceeding could take from 15 to 21 months. During the pendency of the rate case, we continue to collect the rates we filed as permitted under the initial FERC order it received in April 2011. Those rates are subject to refund, including interest, back to October 2011 based on a final disposition of the proceeding. We believe that the resolution of this matter will not have a material impact on our financial position or results of operations.

Table of Contents

The Path 15 project and right of way is owned and operated by Western, a US Federal power agency that operates and maintains approximately 17,000 miles of transmission lines. The project is not subject to the same operating risks of a power plant or the volatility that may arise from changes in the price of electricity or fuel.

Three of our wholly-owned subsidiaries have incurred nonrecourse debt relating to our interest in Path 15. Total debt outstanding at Path 15 as of December 31, 2011 is $145.9 million, which is required to fully amortize over their remaining terms through 2028. See "Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations Liquidity and Capital Resources Project-level debt" for additional details.

*Greeley*

The Greeley facility is a 72 MW combined cycle, gas-fired cogeneration facility located near Greeley, Colorado. Greeley commenced commercial operation in 1988 and is operated and maintained by one of our affiliates. We indirectly own 100% of the project. The electrical output of the facility is sold to PSCo under a PPA expiring in 2013 that provides for the payment of a monthly capacity and energy payment to Greeley. Steam is sold to the University of Northern Colorado ("UNC") under a thermal sales agreement ("TSA"), which also expires in 2013. Under the TSA, the Greeley facility is obligated to sell steam to UNC only as steam is generated during the production of electrical energy for sale to PSCo. The steam is priced such that UNC receives a discount versus its avoided natural gas-fired boiler costs. The natural gas supply for Greeley is obtained on the spot market.

*Manchief*

The Manchief facility is a 300 MW simple-cycle, gas-fired generating plant located in Brush, Colorado. We indirectly own 100% of Manchief. The project achieved commercial operation in 2000 and sells its output to PSCo under a PPA expiring in 2022. The current expiry date of the PPA is a result of a ten-year extension agreed to with PSCo in 2006. Under the PPA, Manchief receives capacity payments and energy payments. The capacity payment is based on the plant's actual net generating capacity available in any given hour up to 301.8 MW. Energy payments are based on the actual electrical energy dispatched by PSCo and consist of tolling fees, start-up fees, heat rate adjustment payments (payable either to or by Manchief) and natural gas transportation charges. PSCo is responsible for providing gas supply to Manchief.

The project and PSCo have entered into an option agreement under which PSCo has the right, in the eighth year of the PPA extension term, to acquire the Manchief facility for $56.5 million. If PSCo exercises its purchase option, the Company would receive a fixed purchase price, as specified in the option agreement.

Manchief is operated and maintained by CEM pursuant to a ten year O&M agreement.

*Morris*

Morris is a wholly-owned 177 MW combined cycle natural gas-fired cogeneration facility located adjacent to the Equistar Chemicals, LP ("Equistar") manufacturing facility in Morris, Illinois. We indirectly own 100% of Morris which operates and maintains the facility. The plant sells electricity and steam to Equistar under an energy supply agreement ("ESA") that expires in 2023, and additional electricity into the PJM merchant market. The facility achieved commercial operation in 1998.

Under the ESA, Equistar pays a tiered energy rate based on the amount of energy consumed up to a maximum of 77 MW. Equistar also pays capacity payments consisting of a non-escalating fixed fee and a variable fee. The steam price under the ESA is based on a tiered pricing schedule calculated as a function of the delivered price of fuel to Equistar. The ESA provides for the renegotiation of the steam

Table of Contents

pricing if steam demand falls below a set range for a stipulated period of time. Equistar has the right to purchase Morris at fair market value at the end of 2013, 2018 and 2023.

The facility purchases natural gas under a long-term agreement with Tenaska Power Services Company ("Tenaska") that expires in 2016. Under the supply agreement, gas pricing is indexed to the Chicago City Gate delivery point. Additionally, Tenaska provides power market trading services through a year-to-year agreement.

*PERH*

We hold 14.3% of the common ownership interests in PERH. The remaining interest in PERH is held by Primary Energy Recycling Corporation ("PERC"), a public company listed on the Toronto Stock Exchange. PERH owns 100% of Primary Energy Operations, LLC, which in turn owns, through its subsidiaries, four wholly-owned recycled energy projects and a 50% interest in a pulverized coal facility.

Pursuant to a long-term management agreement with PERC (the "PERC Management Agreement"), a subsidiary of Atlantic Power provides management and administrative services to PERH and its subsidiaries and, if and to the extent requested by PERC, provides certain administrative services. The initial term of the PERC Management Agreement expires in 2025. In consideration for providing the management and administrative services, we receive a base annual management fee.

On February 16, 2012, we entered into an agreement with PERC, whereby PERC will purchase our 14.3% common ownership interests in PERH for approximately $24 million, plus a management termination fee of approximately $6.1 million. The transaction remains subject to pricing adjustment or termination under certain circumstances. Completion of the transaction is subject to PERC obtaining financing and is expected to occur in the second quarter of 2012.

*Delta-Person*

The Delta-Person project, a 132 MW natural gas-fired peaking facility located near Albuquerque, New Mexico, commenced commercial operation in 2000. We own a 40% interest in Delta-Person and affiliates of Olympus Power, LLC, John Hancock Mutual Life Insurance Company, and ArcLight own the remaining interests. Delta-Person sells all of its electrical output to PNM (formerly Public Service of New Mexico) under a PPA that expires in 2020. The development and construction of the project was financed with two non-recourse term loans expiring in 2017 and 2019, both of which fully amortize over their remaining terms. Our share of the total debt outstanding at Delta-Person as of December 31, 2011 was $9.4 million. See "Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations Liquidity and Capital Resources Project-level debt" for additional details.

The PPA provides for payments from PNM for energy, capacity, house load and other applicable charges. In order to receive its full capacity payments, the Delta-Person project must maintain a minimum availability level. Fuel is provided to the project by an affiliate of PNM. The project's fuel costs are reimbursed by PNM under the PPA.

Olympus Power provides asset management services, which include operational and contractual oversight of the facility and other administrative services. A contractual services agreement in place with GE provides for major maintenance services the cost of which are passed through to PNM under the PPA.

Table of Contents

*Gregory*

The Gregory project is a 400 MW natural gas-fired, combined cycle cogeneration facility located near Corpus Christi, Texas which commenced commercial operation in 2000. Our ownership interest in Gregory is approximately 17%. The other owners include affiliates of J.P. Morgan Chase & Co., John Hancock Life Insurance Company and Rockland Capital. Gregory sells approximately 345 MW of electricity to Fortis Energy Marketing and Trading GP ("Fortis"), up to 33 MW of energy to Sherwin Alumina Company ("Sherwin") and the remainder in the spot market. The project is located on a site adjacent to the Sherwin Alumina production facility, which also serves as Gregory's steam customer. The development and construction of the Gregory project was financed, in part, with a non-recourse loan that matures in 2017 and amortizes over its remaining term. Our share of the total debt outstanding at the Gregory project as of December 31, 2011 was $12.6 million. See "Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations Liquidity and Capital Resources Project-level debt" for additional details.

Electricity is sold to Fortis under a PPA that expires in December 2013. Fortis pays Gregory a capacity payment based on a fixed rate, and an energy payment based on a natural gas price index and a contract heat rate. Sales to Fortis consist of two tranches: a must run block that corresponds to the project's minimum energy output needed to satisfy Sherwin's electricity and steam requirements, and a dispatchable block that can be scheduled at the option of Fortis.

Steam is sold to Sherwin under an agreement that expires in 2020. Under the steam agreement, Gregory is the exclusive source of steam to the Sherwin Alumina plant up to a specified maximum amount.

Gregory purchases natural gas under various short-term and long-term agreements. The project has the option of procuring 100% of its gas requirements from Kinder Morgan Tejas Pipeline, LP, under a market-based gas supply agreement that expires in 2012. Gregory is in discussion to obtain a replacement gas supply agreement that will extend to the expiry of the PPA in 2013.

DPS is responsible for the operation and maintenance of the project under an agreement that terminates in 2015. Tenaska provides energy management services such to the project. Tenaska optimizes Gregory's operation in the ancillary services market of the Electric Reliability Council of Texas, purchases gas for operations, provides scheduling services, provides back-office support and serves as Gregory's retail energy provider and qualified scheduling entity.

**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.

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. According to the North American Electric Reliability Council's Long-Term Reliability Assessment, published in November 2011, summer peak demand within the United States in the ten-year period from 2011 through 2020 is projected to increase approximately 1.1%, while winter peak demand in Canada is projected to increase 1.0%.

Table of Contents

**The non-utility power generation industry**

Our 31 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 $369 billion in 2010, based on information published by the Energy Information Administration in November 2011. 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, there were approximately 5,708 independent power producers representing approximately 408 GW or 42% of capacity in 2009, the most recent year for which data are available. Independent power producers sell the electricity that they generate to electric utilities and other load-serving entities (such as municipalities and electric cooperatives) by way of bilateral contracts or open power exchanges. The electric utilities and other load-serving entities, in turn, generally sell this electricity to industrial, commercial and residential customers.

**INDUSTRY REGULATION**

**Overview**

In the United States, the trend towards restructuring the electric power industry and the introduction of competition in electricity generation began with the passage and implementation of the Public Utility Regulatory Policies Act of 1978, as amended ("PURPA"). Among other things, PURPA, as implemented by the FERC, generally required that vertically integrated electric utilities purchase power from QFs at their avoided cost. The FERC defines avoided cost as the incremental cost to a utility of energy or capacity which, but for the purchase from QFs, the utility would itself generate or purchase from another source. This requirement was modified in 2005, as discussed below. PURPA also provided exemptible relief from typical utility state regulatory oversight and reporting requirements.

Electric transmission assets, such as our Path 15 project, are generally regulated by the FERC on a traditional cost-of-service rate base methodology. This approach allows a transmission company to establish a revenue requirement that provides an opportunity to recover operating costs, depreciation and amortization, and a return on capital. The revenue requirement and calculation methodology is reviewed by the FERC in periodic rate cases. As determined by the FERC, all prudently incurred operating and maintenance costs, capital expenditures, debt costs and a return on equity may be collected in rates charged.

Our Canadian projects are subject to regulation by Canadian governmental agencies. In addition to U.S. environmental regulation, 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 of a facility.

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

**Regulation generating projects**

(i) United States

Ten of our power generating projects are Qualifying Facilities under PURPA and related FERC regulations. The Delta-Person and Pasco projects are exempt wholesale generators ("EWGs") under the Public Utility Holding Company Act of 2005, as amended ("PUHCA") and are therefore exempt from regulations under PUHCA. The generating projects with QF status and which are currently party to a power purchase agreement with a utility or have been granted authority to charge market-based

Table of Contents

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.

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. With the exception of QFs, generation, transmission and distribution of electricity remained largely owned by vertically integrated electric utilities until the enactment of the Energy Policy Act of 1992 (the "EP Act of 1992") and subsequent orders in 1996, along with electric industry restructuring initiated at the state level. Among other things, the EP Act of 1992 enhanced the FERC's power to order open access to power transmission systems, contributing to significant growth in the independent power generation industry.

In August 2005, the Energy Policy Act of 2005 (the "EP Act of 2005") was enacted, which removed certain regulatory constraints on investment in utility power producers. The EP Act of 2005 also limited the requirement from PURPA that electric utilities buy electricity from QFs to certain markets that lack competitive characteristics. Finally, the EP Act of 2005 amended and expanded the reach of the FERC's corporate merger approval authority under Section 203 of the Federal Power Act.

All of our projects are subject to reliability standards developed and enforced by the North American Electric Reliability Corporation ("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.

In March 2007, the FERC issued an order approving mandatory reliability standards proposed by NERC in response to the August 2003 northeastern U.S. blackouts. As a result, 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 ("BCUC").

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

The BCUC to some extent regulates independent power producers. While the BCUC is nominally independent of the government, its chair and commissioners are effectively appointed by the provincial cabinet. All contracts for electricity supply, including those between independent power producers and BC Hydro, must be filed with and approved by 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. However, the BCUC has

Table of Contents

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.

In 2010, the *Clean Energy Act* became law in British Columbia. This Act states, among other things, that British Columbia aims to accelerate and expand development of clean and renewable energy sources within the Province of British Columbia to achieve energy self-sufficiency, economic development and job creation as well as 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.

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

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

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

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

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

Most of the operating assets of the entity formerly known as Ontario Hydro were transferred, in or around 1998, to Hydro One, IESO and a third company called Ontario Power Generation Inc. The

Table of Contents

remaining assets and liabilities were kept in OEFC. Once all of OEFC's debts (approximately $27.1 billion as of March 2011) have been retired, it will be wound up and its assets and liabilities will be transferred directly to the Government of Ontario.

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

**Regulation transmission project**

The revenues received by the Path 15 project are regulated by the FERC through a rate review process every three years that sets an annual revenue requirement. Our filed revenue requirements are subject to review by the FERC staff as well other parties prior to their approval. Differences between our filed revenue requirements and those determined by FERC staff or interveners are subject to a formal settlement process or in the circumstance that settlement cannot be achieved, litigation.

**Carbon emissions**

In the United States, government policy addressing carbon emissions had gained momentum over the last two years, but more recently has slowed at the federal level. Beginning in 2009, the Regional Greenhouse Gas Initiative was established in ten Northeast and Mid-Atlantic states as the first cap-and-trade program in the United States for $CO_2$ emissions. These states have varied implementation plans and schedules. The two states where we have project interests, New York and New Jersey, also provide cost mitigation for independent power projects with certain types of power contracts. At the end of 2011, New Jersey withdrew from the RGGI program. 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.

Federal bills to create both a cap-and-trade allowance system and a renewable/efficiency portfolio standard have been introduced in both the U.S. House and Senate. Separately, the U.S. Environmental Protection Agency has taken several recent actions to potentially regulate $CO_2$ emissions.

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 nuclear, 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.

**COMPETITION**

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

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

We compete for acquisition opportunities with numerous private equity funds, infrastructure funds, Canadian and U.S. independent power firms, utility genco subsidiaries and other strategic and financial players. Our competitive advantages include our competitive access to capital, experienced management team, diversified projects and stability of project cash flow.

## EMPLOYEES

As of February 24, 2012, we had 277 employees, 168 in the U.S. and 109 in Canada. 68 of our Canadian employees are covered by two collective bargaining agreements. During 2011, we did not experience any labor stoppages or labor disputes at any of our facilities.

## ITEM 1A. RISK FACTORS

### Risks Related to Our Business and Our Projects

***Our revenue may be reduced upon the expiration or termination of our power purchase agreements***

Power generated by our projects, in most cases, is sold under PPAs that expire at various times. 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 is possible that the price received by the project for power under subsequent arrangements may be reduced significantly. It is possible that subsequent PPAs may not be available at prices that permit the operation of the project on a profitable basis. If this occurs, the affected project may temporarily or permanently cease operations.

***Our projects depend on their electricity, thermal energy and transmission services customers***

Each of our projects rely 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. The largest customers of our power generation projects, including projects recorded under the equity method of accounting, are PSCo, PEF and OEFC, which purchase approximately 17%,15% and 9%, respectively, of the net electric generation capacity of our projects. The amount of cash available to make payments on our indebtedness, is highly dependent upon customers under such agreements fulfilling their contractual obligations. There is no assurance that these customers will perform their obligations or make required payments.

***Certain of our projects are exposed to fluctuations in the price of electricity***

Those of our projects operating with no PPA or PPAs based on spot market pricing for some or all of their output will be exposed to fluctuations in the wholesale price of electricity. In addition, should any of the long-term PPAs expire or terminate, the relevant project will be required to either negotiate a new PPA or sell into the electricity wholesale market, in which case the prices for electricity will depend on market conditions at the time.

Currently, our most significant exposure to market power prices is 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, the facility can sell approximately 100MW above Equistar'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 Equistar

Table of Contents

demand. At Selkirk, approximately 23% of the capacity of the facility is not contracted and is sold at market prices or not sold at all if market prices do not support the profitable operation of that portion of the facility.

***Our projects may not operate as planned***

The ability of our projects to meet availability requirements and generate the required amount of power to be sold to customers under the PPAs are primary determinants of the amount of cash that will be distributed from the projects to us, and that will in turn be available for dividends paid to our shareholders. There is a risk of equipment failure due to wear and tear, latent defect, design error or operator error, or force majeure events among other things, which could adversely affect revenues and cash flow. To the extent that our projects' equipment requires more frequent and/or longer than forecasted down times for maintenance and repair, or suffers disruptions of plant availability and power generation for other reasons, the amount of cash available for dividends may be adversely affected.

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.

If the reason for a shutdown is outside of the control of the operator, a power generation project may be able to make a force majeure claim for temporary relief of its obligations under the project contracts such as the PPA, fuel supply, steam sales agreement, or otherwise mitigate impacts through business interruption insurance policies, maintenance and debt service reserves. If successful, such insurance claims may prevent a default or reduce monetary losses under such contracts. However, a force majeure claim may be challenged by the contract counterparty and, to the extent the challenge is successful, the outage may still have a materially adverse effect on the project.

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

***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. Furthermore, 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.

Table of Contents

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. To the extent possible, the projects attempt to match fuel cost setting mechanisms in supply agreements to energy payment formulas in the PPA. To the extent that fuel costs are not matched well to PPA energy payments, increases in fuel costs may adversely affect the profitability of the projects, if not otherwise hedged. For example, a portion of the required natural gas at our Auburndale project and all of the natural gas required at our Lake project is purchased at market prices, but the projects' PPAs that expire in 2013 do not effectively pass through changes in natural gas prices. We have executed a hedging program to substantially mitigate this risk through 2013.

***Revenues from windpower projects are highly dependent on suitable wind and associated weather conditions***

We own interests in two windpower projects. 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 resource at any given project site will fall within such specifications.

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

***Insurance may not be sufficient to cover all losses***

Our business involves significant operating hazards related to the generation of electricity. While we believe that the projects' insurance coverage addresses all material insurable risks, provides coverage that is 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, 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, financial condition and future prospects and could adversely affect dividends to our shareholders.

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

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 qualifying facility 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.

In August 2005, the Energy Policy Act of 2005 was enacted, which removed certain regulatory constraints on investment in utility power producers. The Energy Policy Act of 2005 also limited the requirement that electric utilities buy electricity from qualifying facilities 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. Finally, the Energy Policy Act of 2005 amended and expanded the reach of the FERC's merger approval authority.

If any project that is a QF were to lose its status as a QF, then such project may no longer be entitled to exemption from provisions of the Public Utility Holding Company Act of 2005 or from provisions of the Federal Power Act and state law and regulations. Such project may be able to obtain exempt wholesale generator status to maintain its exemption from the provisions of the Public Utility Holding Company Act of 2005; however, our projects may not be able to obtain such exemptions. Loss of QF status could 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.

The Energy Policy Act of 2005 provides incentives for various forms of electric generation technologies, which may subsidize our competitors. In addition, pursuant to the Energy Policy Act of 2005, the FERC selected an electric reliability organization to impose mandatory reliability rules and standards. Among other things, the FERC's rules implementing these provisions allow such reliability organizations to impose sanctions on generators that violate their new reliability rules.

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

Generally, in Canada, our projects are subject to energy regulation primarily by the relevant provincial authorities.

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 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.

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 could impact the market for electricity generated by our British Columbia projects. This risk is mitigated in part because, in general, BC Hydro is currently limited by regulation to undertaking efficiency improvements at its existing facilities and only undertaking development of new generation 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 BCUC to some extent regulates independent power producers. While the BCUC is nominally independent of the government, its chair and commissioners are effectively appointed by the provincial cabinet. All contracts for electricity supply, including those between independent power producers and BC Hydro, must be filed with and approved by 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.

Table of Contents

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

***Future FERC rate determinations could negatively impact Path 15's cash flows***

The stability of Path 15's cash flows will continue to be subject to the risk of the FERC's adjusting the expected formulation of revenues as a result of its rate review every three years and the participation therein by interveners who may argue for lower rates. Such a rate review commenced in February 2011. The cost-of-service methodology currently applied by the FERC is well established and transparent; however, certain inputs in the FERC's determination of rates are subject to its discretion, including its response to protests from interveners in such rate cases, which include return on equity and the recovery of certain extraordinary expenses. Unfavorable decisions on these matters could adversely affect the cash flow, financial position and results of operations of us and Path 15, and could adversely affect our cash available for dividends.

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

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 the 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 through self-certification, compliance audits, spot checking, self-reporting, compliance investigations by NERC (or a regional reliability organization) and the FERC, periodic data submittals, exception reporting, and complaints. The penalty that might 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.

Table of Contents

***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 continuously improve environmental, health and safety performance.

The Clean Air Act and related regulations and programs of the EPA extensively regulate the air emissions of sulfur dioxide, nitrogen oxides, mercury and other compounds by power plants. Environmental laws and regulations have generally become more stringent over time, and this trend may continue. In particular, the EPA promulgated the final Cross-State Air Pollution Rule ("CSAPR") which replaces the Clean Air Interstate Rule ("CAIR") and requires 27 states and the District of Columbia to curb emissions of sulfur dioxide and nitrogen oxides from power plants through more aggressive state-by-state emissions limits for nitrogen oxides and sulfur dioxide. The first phase of compliance was to begin on January 1, 2012 and the second (and more restrictive) phase would begin on January 1, 2014. On December 30, 2011, the U.S. Court of Appeals stayed CSAPR pending hearings in April 2012 and a possible decision late in 2012. In the interim, the regulations of the CAIR remain in place. Compliance with the new rule, when implanted, may have a material adverse impact on our business, operations or financial condition.

The EPA proposed new mercury and air toxics emissions standards for power plants on May 3, 2011 and issued a final rule on December 16, 2011. Meeting these new standards at our coal-fired facility may have a material adverse impact on our business, operations or financial condition.

The Resource Conservation and Recovery Act has historically exempted fossil fuel combustion wastes from hazardous waste regulation. However, in June 2010 the Environmental Protection Agency proposed two alternative sets of regulations governing coal ash. One set of proposed regulations 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 set of proposed regulations would regulate coal ash as a non-hazardous solid waste. If the Environmental Protection Agency determines to regulate coal ash as a hazardous waste, our 40% owned coal-fired facility may be subject to increased compliance obligations and costs associated that may have a material adverse impact on our business, operations or financial condition.

Significant costs may be incurred for either capital expenditures or the purchase of allowances under any or all of these programs to keep the projects compliant with environmental laws and regulations. The projects' PPAs do not allow for the pass through of emissions allowance or emission reduction capital expenditure costs, with the exception of Pasco. However, the Selkirk project has such a PPA without pass-through, yet participated in a settlement with New York utilities, IPPs and the state in which any required RGGI costs shall nonetheless be reimbursed to the IPPs. 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.

Table of Contents

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

Ongoing public concerns about emissions of $CO_2$ and other greenhouse gases have resulted in the enactment of, and proposals for, laws and regulations at the federal, state and regional levels, some of which do or could apply to some of our project operations. For example, the multi-state $CO_2$ cap-and-trade program, known as the Regional Greenhouse Gas Initiative, applies to our fossil fuel facilities in the Northeast region. The Regional Greenhouse Gas Initiative program went into effect on January 1, 2009. $CO_2$ allowances are now a tradable commodity.

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

In 2006, the State of California passed legislation initiating two programs to control/reduce the creation of greenhouse gases. The two laws are more commonly known as AB 32 and SB 1368. Under AB 32 (the Global Warming Solutions Act), the California Air Resources Board ("CARB") is required to adopt a greenhouse gas emissions cap on all major sources (not limited to the electric sector). In order to do so, it must adopt regulations for the mandatory reporting and verification of greenhouse gas emissions and to reduce state-wide emissions of greenhouse gases to 1990 levels by 2020. On October 20, 2011, the CARB adopted rules whose first phase will take full effect on January 1, 2013. Starting that date, electricity generators and certain other facilities will be subject to an allowance for greenhouse gas emissions. Allowances will be allocated by both formulas set by the CARB and auctions. Legal challenges to the program are underway and additional challenges are anticipated.

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 power purchase agreements 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 associated with combined-cycle, gas turbine baseload generation, such as our North Island project.

In addition to the regional initiatives, legislation for the reduction of greenhouse gases has been introduced at the federal level and if passed, may eventually override the regional efforts with a national cap and trade program. To date, however, federal bills to create both a cap-and-trade allowance system and a renewable/efficiency portfolio standard have not been adopted into law. Separately, the Environmental Protection Agency has taken several recent actions for the regulation of greenhouse gas emissions.

The Environmental Protection Agency's actions include its 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 requires large sources, including power plants, to monitor

Table of Contents

and report greenhouse gas emissions to the Environmental Protection Agency annually starting in 2011, and its publication in May 2010 of its final Prevention of Significant Deterioration and Title V Greenhouse Gas Tailoring Rule, which took effect in 2011 and 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. Proposed EPA regulations to impose greenhouse gas new source performance standards for electricity utility stream generating units are anticipated in 2012.

The implementation of existing $CO_2$ and other greenhouse gas legislation or regulation, the introduction of new regulation, or other future regulatory developments may subject the Company to increased compliance obligations and costs that could have a material adverse impact on our business, operations or financial condition.

All of our generating facilities complied with the March 31, 2011 requirement to submit 40 CFR Part 98 Mandatory Greenhouse Gas reporting for the emission of eligible site generated greenhouse gases in 2010. This is a national requirement and stands as a start in developing a baseline for greenhouse gases emissions at a national level.

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

The power generation industry is characterized by intense competition, and our projects encounter competition from utilities, industrial companies and other independent power producers, in particular with respect to uncontracted output. In recent years, there has been increasing competition among generators for power sales agreements, and this has contributed to a reduction in electricity prices in certain markets where supply has surpassed demand plus appropriate reserve margins. Increasing competition among participants in the power generation industry may adversely affect our performance and the performance of our projects.

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

In a number of cases, 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 Caithness, PPMS and Western) operate many of the projects. As such, we must rely on the technical and management expertise of these third-party operators, although typically we are represented on a management or operating committee if we do not own 100% of a project. To the extent that such third-party operators do not fulfill their obligations to manage the operations of the projects or are not effective in doing so, the amount of cash available to pay dividends may be adversely affected.

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

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

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

Table of Contents

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

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

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

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

We and the projects may use derivative instruments, including futures, forwards, options and swaps, to manage commodity and financial market risks. In the future, the project operators could recognize financial losses on these arrangements as a result of volatility in the market values of the underlying commodities or if a counterparty fails to perform under a contract. 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.

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 (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 (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 financial condition, results of operations and cash flows. We have executed natural gas swaps to reduce our risks to changes in the market price of natural gas, which is the fuel consumed at many of our projects. Due to declining natural gas prices, we have incurred losses on these natural gas swaps. We execute these swaps only for the purpose of managing risks and not for speculative trading.

***Construction projects are subject to construction risk***

In any construction project, there is a risk that circumstances occur which prevent the timely completion of a project, cause construction costs to exceed the level budgeted, or result in operating performance standards not being met. In the event a power project does not achieve commercial operation by its expected date, the project may be subject to increased construction costs associated with the continuing accrual of interest on the project's construction loan, which customarily matures at the start of commercial operation and converts to a term loan. A delay in completion of construction may also impact a project under its PPA which may include penalty provisions for a delay in commercial operation date or in situations of extreme delay, termination of the PPA.

Table of Contents

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

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

The Piedmont project commenced construction in November 2010 and is expected to be completed in late 2012. A delay in completion could result in the delay and/or loss of the proceeds from the 1603 grant.

***Certain employees are subject to collective bargaining***

A number of our plant employees, 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.

***Our Pension Plan may require future contributions***

Certain of our employees in Canada are participants in a defined benefit pension plans that we sponsor. As of December 31, 2011, the unfunded pension liability on our pension plan was approximately $2.2 million. The 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.

**Risks Related to Our Structure**

***Distribution of available cash may restrict our potential growth***

A payout of a significant portion of our operating cash flow may make additional capital and operating expenditures dependent on increased cash flow or additional financing in the future. Lack of these funds could limit our future growth and cash flow. In addition, we may be precluded from pursuing otherwise attractive acquisitions or investments if the projected short-term cash flow from the acquisition or investment is not adequate to service the capital raised to fund the acquisition or investment.

***Future dividends are not guaranteed***

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

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

Our payments to shareholders, some of our corporate-level long-term debt and convertible debenture holders are denominated in Canadian dollars. Conversely, some of our projects' revenues and expenses are denominated in U.S. dollars. As a result, we are exposed to currency exchange rate risks. Despite our hedges against this risk through 2015, any arrangements to mitigate this exchange rate risk may not be sufficient to fully protect against this risk. If hedging transactions do not fully protect against this risk, changes in the currency exchange rate between U.S. and Canadian dollars could adversely affect our cash available for distribution.

***Our indebtedness and financing arrangements could negatively impact our business and our projects***

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

- our ability in the future to obtain additional financing for working capital, capital expenditures, acquisitions or other purposes may be limited; and

- our ability to refinance indebtedness on terms acceptable to us or at all.

As of December 31, 2011, our consolidated long-term debt represented approximately 59.1% of our total capitalization, comprised of debt and balance sheet equity.

Our current or future borrowings could increase the level of financial risk to us and, to the extent that the interest rates are not fixed and rise, or that borrowings are refinanced at higher rates, then cash available for dividends could be adversely affected. Changes in interest rates do not have a significant impact on cash payments that are required on our debt instruments as approximately 88% of our debt, including our share of the project-level debt associated with equity investments in affiliates, either bears interest at fixed rates or is financially hedged through the use of interest rate swaps.

As of February 24, 2012, we had $72.8 million outstanding under our revolving credit facility, $192.2 million of outstanding convertible debentures, $333.8 million of outstanding non-recourse project-level debt, and $1.1 billion of unsecured notes. Covenants in these borrowings may also adversely affect cash available for dividends. In addition, some of the projects currently have non-recourse term loans or other financing arrangements in place with various lenders. These financing arrangements are typically secured by all of the project assets and contracts as well as our equity interests in the project. The terms of these financing arrangements generally impose many covenants and obligations on the part of the borrower. For example, some agreements contain requirements to maintain specified historical, and in some cases prospective debt service coverage ratios before cash may be distributed from the relevant project to us. In many cases, an uncured default by any party under key project agreements (such as a PPA or a fuel supply agreement) will also constitute a default under the project's term loan or other financing arrangement. Failure to comply with the terms of these term loans or other financing arrangements, or events of default thereunder, may prevent cash distributions by the particular project(s) to us and may entitle the lenders to demand repayment and/or enforce their security interests, which could have a material adverse effect on our business, results of operations and financial condition. In addition, failure to comply with the terms, restrictions or obligations of any of our revolving credit facility, convertible debentures or unsecured notes or any other financing arrangements, borrowings or indebtedness, or events of default thereunder, may entitle the lenders to demand repayment, accelerate related debt as well as any other debt to which a cross-default or cross-acceleration provision applies and/or enforce their security interests, which could have a material adverse effect on our business, results of operations and financial condition.

Our failure to refinance or repay any indebtedness when due could constitute a default under such indebtedness. Under such circumstances, it is expected that dividends to our shareholders would not be permitted until such indebtedness was refinanced or repaid.

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

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

Changes to our perceived creditworthiness may affect the market price or value and the liquidity of our common shares. The interest rate we pay on our credit facility may increase if certain credit ratios deteriorate.

***Investment eligibility***

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.

***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 completed our initial public offering on the TSX in November 2004. At the time of the initial public offering, our public security was an IPS. Each IPS was comprised of one common share and Cdn$5.767 principal value of 11% subordinated notes due 2016. In the fourth quarter of 2009, we converted to a traditional common share company through a shareholder approved plan of arrangement in which each IPS was exchanged for one of our new common shares. Our new common shares were listed and posted for trading on the TSX commencing on December 2, 2009 and trade under the symbol "ATP," and the former IPSs, which traded under the symbol "ATP.UN," were delisted at that time. In connection with our conversion from an IPS structure to a traditional common share structure and the related reorganization of our organizational structure, we received a note from our primary U.S. holding company (the "Intercompany Note"). We are required to include, in computing our taxable income, interest on the Intercompany Note.

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

***Other Canadian federal income tax risks***

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.

Table of Contents

***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 "the Partnership Financing Arrangements") in place. We claim interest deductions in the U.S. with respect to the Partnership Financing Arrangements. To the extent any interest expense under the subordinated notes, the Intercompany Note or the Partnership Financing Arrangements is disallowed or is otherwise not deductible, the U.S. federal income tax liability of our U.S. holding companies will increase, which could materially affect the after-tax cash available to distribute to us.

While we received advice from our U.S. tax counsel, based on certain representations by us and our U.S. holding companies and determinations made by our independent advisors, as applicable, that the subordinated notes and the Intercompany Note should be treated as debt for U.S. federal income tax purposes, and the Partnership has received advice from its U.S. accountants, based on certain representations by its holding companies, that the payments on the Partnership Financing Arrangements should be deductible for U.S. federal income tax purposes, it is possible that the Internal Revenue Service ("IRS") could successfully challenge these positions and assert that any of these arrangements be treated as equity rather than debt for U.S. federal income tax purposes or that the interest on such arrangements are 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 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.

Furthermore, 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, in 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 in 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 its net interest expense (the interest paid by our U.S. holding company on all debt, including the Intercompany Note and the Partnership Financing Arrangements, less its interest income) exceeds 50% of their adjusted taxable income (generally, U.S. federal taxable income before net interest expense, net operating loss carryovers, depreciation and amortization). Any disallowed interest

Table of Contents

expense may currently be carried forward to future years. Moreover, proposed legislation has been introduced, though not enacted, several times in recent years that would further limit the 50% of adjusted taxable income cap described above to 25% of adjusted taxable income, although recent proposals in the Fiscal Year Budget for 2010 would only apply the revised rules to certain foreign corporations that were expatriated. Furthermore, 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 company 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. 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 future limitations, our ability to realize these benefits may be limited. A reduction in our net operating losses, or a limitation on our ability to use such losses, may result in a material increase in our future income tax liability. Our U.S. Holding companies include the Partnership's U.S. Holding company, Atlantic Power (US) GP, which has net operating loss carryforwards attributable to tax years prior to our acquisition. It is anticipated that these net operating loss carryforwards will be available to offset future taxable income of Atlantic Power (US) GP; however, their use may be subject to an annual limitation. While we expect these losses will be available to us as a future benefit, in the event that they are successfully challenged by the IRS or subject to additional future limitations, our ability to realize these benefits may be limited. A reduction in our net operating losses, or additional limitations on our ability to use such losses, may result in a material increase in our future income tax liability.

***Passive foreign investment company treatment***

We do not believe that we are a passive foreign investment company, and we do not expect to become a passive foreign investment company. However, if we were a passive foreign investment company while a taxable U.S. holder held common shares, such U.S. holder could be subject to an interest charge on any deferred taxation and the treatment of gain upon the sale of our stock as ordinary income.

**Risks Related to the Acquisition of the Partnership**

***The failure to integrate successfully the businesses of Atlantic Power and the Partnership in the expected timeframe would adversely affect the combined company's future result***

The success of our acquisition of the Partnership, which was completed in the fourth quarter of 2011, will depend, in large part, on our ability to realize the anticipated benefits, including modest cost savings, from combining the businesses of Atlantic Power and the Partnership. To realize these anticipated benefits, the businesses of Atlantic Power and the Partnership must be successfully integrated. This integration will be complex and time-consuming. The failure to integrate successfully and to manage successfully the challenges presented by the integration process may result in the combined company not fully achieving the anticipated benefits of the Plan of Arrangement.

Potential difficulties that may be encountered in the continuing integration process include the following:

- challenges associated with managing the larger, more complex, combined business;

Table of Contents

- conforming standards, controls, procedures and policies, business cultures and compensation structures between the entities;
- integrating personnel from the two entities while maintaining focus on developing, producing and delivering consistent, high quality services;
- consolidating corporate and administrative infrastructures;
- coordinating geographically dispersed organizations;
- potential unknown liabilities and unforeseen expenses, delays or regulatory conditions;
- performance shortfalls at one or both of the entities as a result of the diversion of management's attention caused integrating the entities' operations; and
- the ability of the combined company to deliver on its strategy going forward.

***If goodwill or other intangible assets that we record in connection with the acquisition become impaired, we could have to take significant charges against earnings***

In connection with the accounting for the acquisition, we have recorded a significant amount of goodwill and other intangible assets. Under U.S. GAAP, we must assess, at least annually and potentially more frequently, whether the value of goodwill and other indefinite-lived intangible assets have been impaired. Amortizing intangible assets will be assessed for impairment in the event of an impairment indicator. Any reduction or impairment of the value of goodwill or other intangible assets will result in a charge against earnings, which could materially adversely affect our results of operations and shareholders' equity in future periods.

***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. Experienced employees in the power industry are in high demand and competition for their talents can be intense. Employees of both Atlantic Power and the Partnership may experience uncertainty about their future role with the combined company even after, strategies with regard to the combined company are announced or executed. The potential distractions may adversely affect our ability to attract, motivate and retain executives and other key employees and keep them focused on applicable strategies and goals. A failure to retain and motivate executives and other key employees could have an adverse impact on our business.

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

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

**ITEM 1B. UNRESOLVED STAFF COMMENTS**

None

Table of Contents

## ITEM 2. PROPERTIES

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

Our principal executive office is located at 200 Clarendon Street, Floor 25, Boston, Massachusetts under a lease that expires in 2015.

## ITEM 3. LEGAL PROCEEDINGS

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

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

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

## ITEM 4. MINE SAFETY DISCLOSURES

Not applicable.

Table of Contents

## 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 common shares, as applicable, as reported by the TSX for the periods indicated:

| Period | High (Cdn$) | Low (Cdn$) |
|---|---|---|
| Quarter ended December 31, 2011 | $ 14.94 | $ 13.09 |
| Quarter ended September 30, 2011 | 15.46 | 12.92 |
| Quarter ended June 30, 2011 | 15.72 | 13.82 |
| Quarter ended March 31, 2011 | 15.50 | 14.41 |
| Quarter ended December 31, 2010 | 15.18 | 13.31 |
| Quarter ended September 30, 2010 | 14.47 | 12.11 |
| Quarter ended June 30, 2010 | 12.90 | 11.20 |
| Quarter ended March 31, 2010 | 13.85 | 11.50 |

Our shares began trading on the NYSE under the symbol "AT" on July 23, 2010. 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, 2011:

| Period | High (US$) | Low (US$) |
|---|---|---|
| Quarter ended December 31, 2011 | $ 14.55 | $ 12.52 |
| Quarter ended September 30, 2011 | 16.34 | 13.12 |
| Quarter ended June 30, 2011 | 16.18 | 14.33 |
| Quarter ended March 31, 2011 | 15.75 | 14.72 |
| Quarter ended December 31, 2010 | 14.98 | 13.26 |
| July 23, 2010 through September 30, 2010 | 14.00 | 12.10 |

The number of holders of common shares was approximately 84,700 on February 24, 2012.

**Dividends**

Dividends declared per common share in 2011 and 2010 were as follows (Cdn$):

| Month | 2011 | 2010 |
|---|---|---|
| | Amount | |
| January | $ 0.0912 | $ 0.0912 |
| February | 0.0912 | 0.0912 |
| March | 0.0912 | 0.0912 |
| April | 0.0912 | 0.0912 |
| May | 0.0912 | 0.0912 |
| June | 0.0912 | 0.0912 |
| July | 0.0912 | 0.0912 |
| August | 0.0912 | 0.0912 |
| September | 0.0912 | 0.0912 |
| October | 0.0912 | 0.0912 |
| November | 0.0954 | 0.0912 |
| December | 0.0958 | 0.0912 |

Table of Contents

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

The following table provides information as of December 31, 2011 regarding our Long-Term Incentive Plan. For the description of our Long-Term Incentive Plan, see "Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations Critical Accounting Policies and Estimates Long-term incentive plan."

| | Number of securities to be issued upon exercise of outstanding options, warrants and rights(1) | Number of securities remaining available for future issuance under equity compensation plans(1)(2) |
|---|---|---|
| Equity compensation plans approved by security holders | 485,781 | 590,314 |

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

(2) The maximum aggregate number of common shares that may be issued under our Long-Term Incentive Plan upon redemption of notional shares is 1,350,000 shares.

**Performance Graph**

The performance graph below compares the cumulative total shareholder return on our common shares for the period December 31, 2004, through December 31, 2011, 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 trades on the New York Stock Exchange under the symbol "AT" and the Toronto Stock Exchange under the symbol "ATP". The performance graph shown below is being provided as furnished and compares each period assuming that an investment was made on December 31, 2005, in each of our common shares, the stocks included in the S&P 500 and the stocks included in the S&P/TSX, and that all dividends were reinvested.

Table of Contents

**Total Shareholder Return 2005-2011**

## 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, 2011 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, 2011.

| | Year Ended December 31, | | | | |
|---|---|---|---|---|---|
| **(in thousands of U.S. dollars, except as otherwise stated)** | **2011[(a)]** | **2010** | **2009** | **2008** | **2007** |
| Project revenue | $ 284,895 | $ 195,256 | $ 179,517 | $ 173,812 | $ 113,257 |
| Project income | 33,979 | 41,879 | 48,415 | 41,006 | 70,118 |
| Net (loss) income attributable to Atlantic Power Corporation | (38,408) | (3,752) | (38,486) | 48,101 | (30,596) |
| Basic earnings per share, US$ | $ (0.50) | $ (0.06) | $ (0.63) | $ 0.78 | $ (0.50) |
| Basic earnings per share, Cdn$[(b)] | $ (0.49) | $ (0.06) | $ (0.72) | $ 0.84 | $ (0.53) |
| Diluted earnings per share, US$[(c)] | $ (0.50) | $ (0.06) | $ (0.63) | $ 0.73 | $ (0.50) |
| Diluted earnings per share, Cdn$[(b)(c)] | $ (0.49) | $ (0.06) | $ (0.72) | $ 0.78 | $ (0.53) |
| Per IPS distribution declared | $ | $ | $ 0.51 | $ 0.60 | $ 0.59 |
| Per common share dividend declared | $ 1.11 | $ 1.06 | $ 0.46 | $ 0.40 | $ 0.40 |
| Total assets | $ 3,248,427 | $ 1,013,012 | $ 869,576 | $ 907,995 | $ 880,751 |
| Total long-term liabilities | $ 1,940,192 | $ 518,273 | $ 402,212 | $ 654,499 | $ 715,923 |

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

(b) The Cdn$ amounts were converted using the average exchange rates for the applicable periods

(c) Diluted earnings (loss) per share US$ is computed including dilutive potential shares, which include those issuable upon conversion of convertible debentures and under our long term incentive plan. Because we reported a loss during the years ended December 31, 2011, 2010, 2009, and 2007, 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 per share for the periods presented.

Table of Contents

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

*The following management's discussion and analysis of financial condition and results of operations should be read in conjunction with our audited consolidated financial statements included in this Annual Report on Form 10-K. All dollar amounts discussed below are in thousands of U.S. dollars, unless otherwise stated. The financial statements have been prepared in accordance with accounting principles generally accepted in the United States of America ("GAAP").*

### Overview of Our Business

Atlantic Power Corporation owns and operates a diverse fleet of power generation and infrastructure assets in the United States and Canada. Our power generation projects sell electricity to utilities and other large commercial customers largely under long-term power purchase agreements, which seek to minimize exposure to changes in commodity prices. Our power generation projects in operation have an aggregate gross electric generation capacity of approximately 3,397 MW in which our ownership interest is approximately 2,140 MW. Our current portfolio consists of interests in 31 operational power generation projects across 11 states in the United States and two provinces in Canada, one 53 MW biomass project under construction in Georgia, and a 500-kilovolt 84-mile electric transmission line located in California. We also own a majority interest in Rollcast Energy, a biomass power plant developer with several projects under development, and a 14.3% common equity interest in PERH. Twenty-three of our projects are wholly-owned subsidiaries.

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

Our power generation projects generally operate pursuant to long-term fuel supply agreements, typically accompanied by fuel transportation arrangements. In most cases, the fuel supply and transportation arrangements correspond to the term of the relevant PPAs and many of the PPAs and steam sales agreements provide for the indexing or pass-through of fuel costs to our customers. In cases where there is not an effective pass-through of fuel costs, we attempt to mitigate a significant portion of the market price risk of fuel purchases through the use of hedging strategies.

While we operate and maintain more than half of our power generation fleet, we also partner with recognized leaders in the independent power industry to operate and maintain our other projects, including Caithness Energy, LLC, CEM, PPMS and Western. Under these operation, maintenance and management agreements, the operator is typically responsible for operations, maintenance and repair services.

We revised our reportable business segments during the fourth quarter of 2011 upon completion of the Partnership acquisition. The new operating segments are Northeast, Northwest, Southeast, Southwest and Un-allocated Corporate. Our financial results for the years ended December 31, 2010 and 2009 have been presented to reflect these changes in operating segments. We revised our segments to align with changes in management's resource allocation and performance assessment in making decisions regarding our operations. These changes reflect our current operating focus. The segment classified as Un-allocated Corporate includes activities that support the executive offices, capital structure and costs of being a public registrant. These costs are not allocated to the operating segments when determining segment profit or loss.

Table of Contents

**Current Trends in Our Business**

*Macroeconomic impacts*

The recession caused significant decreases in both peak electricity demand and consumption that varied by region, although as always, summer and winter peak demand will also be greatly influenced by weather. This has had the effect of delaying projected increases in capacity requirements to varying degrees by region. Typically, electricity demand makes a strong recovery to pre-recession levels along with the economic recovery and the projected delays in capacity needs tend to revert to some extent as well, depending on the pace of the recovery. The reduced electricity peak demand and consumption during a recession tends to impact base load (plants that typically operate at all times) and peaking plants (those that only operate in periods of very high demand) more than mid-merit plants (those that operate for a portion of most days, but not at night or in other lower demand periods). During recessionary periods, base load plants may be called on for lower levels of off-peak generation and peaking plants may be called on less 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. One other recession related industry impact was an easing of commodity costs, whose previous escalation had greatly increased new plant construction costs. The economic recovery has moved prices higher again for copper, steel and other inputs, with labor costs a function of regional power plant and general construction activity levels, which in some locations includes increased renewable project construction.

*Increased renewable power projects*

The combination of federal stimulus and other tax provisions in the U.S. 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. One simple impact of this trend is the offsetting reduction in new fossil-fired generation, with the following exception, because significant renewable capacity is being built as intermittent resources (e.g., wind and solar) there will be an increased need by system operators to have more "firming resources." These are units that can be started quickly or idle at low levels in order to be available to compensate for sudden decreases in output from the solar or wind projects. These firming resources are generally natural gas-fired generators or, in more limited locations, pumped storage or reservoir-based hydro resources. The second significant impact of increased renewable projects is the increased need for new transmission lines to move power from renewable resources in typically more remote locations, to the more highly populated electricity load centers. This transmission requirement will require significant capital and tends to encounter a long and risky development, siting and regulatory process.

*Increased shale gas resources*

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

The lower power prices can have an adverse impact on development of new renewable projects whose owners are attempting to negotiate power purchase agreements at favorable levels to support the financing and construction of the projects. The expectation of reduced future volatility of gas prices due to increased supply has reinforced a growing expectation of the role of natural gas as a "bridging fuel,"

Table of Contents

helping from a carbon policy perspective to bridge the desired U.S. transition to both cleaner fuels and more commercially viable carbon removal and sequestration technologies.

*Credit markets*

Weak and volatile credit markets over the past three years reduced the number of lenders providing power project financing, as well as the size and length of loans, resulting in higher costs for such financing. This reduces the number of new power projects that could be feasibly financed and built. Credit market conditions for project-lending have generally improved, but are still weaker than pre-recession levels. However, base lending rates such as LIBOR have stayed quite low by historical standards, somewhat compensating for the increased interest rate spreads demanded by lenders. Corporate-level credit markets experienced similar adverse impacts, which impeded the ability of many development companies to obtain financing for new power projects.

**Factors That May Influence Our Results**

Our primary objective is to generate consistent levels of cash flow to support dividends to our shareholders, which we refer to as "Cash Available for Distribution." Because we believe that our shareholders are primarily focused on income and secondarily on capital appreciation, we provide supplementary cash flow-based non-GAAP information in Item 7 and discuss our results in terms of these non-GAAP measures, in addition to analysis of our results on a GAAP basis. See "Supplementary Non-GAAP Financial Information" below for additional details.

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

*Financial performance of our projects*

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

- While approximately 46% of our power generation revenue in 2011 was related to contractual capacity payments, commodity prices do influence our variable revenues and the cost of fuel. Our PPAs are generally structured to minimize our risk to fluctuations in commodity prices by passing the cost of fuel through to the utility and its customers, but some of our projects do have exposure to market power and fuel prices. For example, a portion of the natural gas required for projects in our Southeast segment is purchased at spot market prices but not effectively passed through in their PPAs. Our Orlando project should benefit from switching to market prices for natural gas when its fuel contract expires in 2013 since the contract prices are above current and projected spot prices. We have executed a hedging strategy to partially mitigate this risk. See "Item 7A. Quantitative and Qualitative Disclosures About Market Risk" for additional details about our hedging program at our Southeast segment projects. Our most significant exposure to market power prices exists at the Selkirk, Chambers and Morris projects. At Chambers, our utility customer has the right to sell a portion of the plant's output to the spot power market if it is economical to do so, and the Chambers project shares in the profits from those sales. With low demand for electricity the utility reduces its dispatch to minimum contracted levels during off-peak hours. At Selkirk, approximately 23% of the capacity of the

Table of Contents

facility is currently not contracted and is sold at market power prices or not sold at all if market prices do not support profitable operation of that portion of the facility. Additionally at Morris, approximately 56% of the facility's capacity is currently not contracted and is sold at market power prices or not sold at all if market prices do not support profitable operation of the facility. 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. In particular, the power agreements for our Kenilworth facility expires in 2012 and our Lake, Auburndale and Greeley projects expire in 2013. We expect these projects to continue operating under new PPAs and generating Cash Available for Distribution after their existing power contracts expire, but at significantly lower levels. The degree of the expected decline in Cash Available for Distribution is subject to market conditions when we execute new power agreements for these projects and is difficult to estimate at this time. These projects will be free of debt when their PPAs expire, which provides us with some flexibility to pursue the most economic type of contract without restrictions that might be imposed by project-level debt.

Some of our projects have non-recourse project-level debt that can restrict the ability of the project to make cash distributions. The project-level debt agreements typically contain cash flow coverage ratio tests that restrict the project's cash distributions if project cash flows do not exceed project-level debt service requirements by a specified amount. The Selkirk, Gregory and Delta-Person projects and Epsilon Power Partners, the holding company for our ownership in the Chambers project, are currently not meeting their cash flow coverage ratio tests and they are restricted from making cash distributions. We expect to resume receiving distributions from Selkirk in 2012, Gregory and Delta-Person in 2014 and Epsilon Power Partners in 2013. See the "Project-level debt" section of "Liquidity and Capital Resources Project-level debt" for additional details.

*Non-cash gains and losses on derivatives instruments*

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

*Interest expense and other costs associated with debt*

Interest expense relates to both non-recourse project-level debt and corporate-level debt. 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.

**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 generally accepted accounting principles 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 deferred tax assets, the valuation of shares associated with our Long-Term Incentive Plan and the fair value of derivatives.

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

*Impairment of long-lived assets and equity investments*

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

Investments in and the operating results of 50%-or-less owned entities not required to be consolidated are included in the consolidated financial statements on the basis of the equity method of accounting. We review our investments in unconsolidated entities for impairment whenever events or changes in business circumstances indicate that the carrying amount of the investments may not be fully recoverable. 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, failure of cash flow coverage ratio tests included in project-level, non-recourse debt 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.

*Goodwill*

At December 31, 2011, we reported goodwill of $343.6 million, consisting of $331.1 million resulting from the November 5, 2011 acquisition of the Partnership, $9.0 million associated with the Path 15 project in the Southwest segment and $3.5 million that is associated with the step-up acquisition of Rollcast in March 2010 in Un-allocated Corporate segment. See Note 3, *Acquisitions and divestments* to the Consolidated Financial Statements for further discussion.

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 identified by assessing whether the components of our operating segments constitute businesses for which discrete financial information is available and whether segment management regularly reviews the operating results of those components. If it is determined that the fair value of a reporting unit is below its carrying amount, where necessary, our goodwill will be impaired at that time.

We did not perform an annual impairment assessment for goodwill recorded resulting from the Partnership acquisition as no changes occurred that would impact the fair value attributed during the purchase price allocation performed at the acquisition date.

We performed our annual goodwill impairment assessment as of December 31, 2011, for Path 15 and Rollcast which are at the operating segment levels. We determined the fair value of these reporting units using an income approach. Significant inputs to the determination of fair value were as follows:

Path 15 We applied a discounted cash flow methodology to the project's long-term budget. This approach is consistent with that used to determine fair value in prior years. The cash flows in the budget are based on our estimated allowable future recoveries by the FERC for transmission revenue.

Rollcast We applied a discounted cash flow methodology to Rollcast's long-term budget. This approach is consistent with that used to determine fair value in prior years. The cash flows in the budget are based on our estimated future cash flows from projects currently in development and expected to be placed into service or sold.

If fair value of a reporting unit exceeds its carrying value, goodwill of the reporting unit is not considered impaired. Under the income approach described above, we estimated the fair value of Path 15 to exceed its carrying value by approximately 16% and the fair value of Rollcast to exceed its carrying value by approximately 414% at December 31, 2011.

Our estimate of fair value under the income approach described above is affected primarily by assumptions about the results of future rate cases and the ability of Rollcast to develop future biomass projects. Our estimates for Path 15 are based on prior rate case settlements. Estimating allowed recoveries from a regulatory agency contains significant uncertainty. If the results of future cases are not consistent with past results, our goodwill may become impaired, which would result in a non-cash charge, not to exceed $9.0 million. If Rollcast is unable to complete development of its budgeted projects our goodwill may become impaired, which would result in a non-cash charge, not to exceed $3.5 million.

*Fair value of derivatives*

We utilize derivative contracts to mitigate our exposure to fluctuations in fuel commodity prices and foreign currency and to balance our exposure to variable interest rates. We believe that these derivatives are generally effective in realizing these objectives.

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 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

Table of Contents

Canada and available tax planning strategies. The valuation allowance is comprised primarily of provisions against available Canadian and U.S. net operating loss carryforwards.

*Long-term incentive plan*

The officers and certain other employees of Atlantic Power are eligible to participate in the LTIP that was implemented in 2007. In the second quarter of 2010, the Board of Directors approved an amendment to the LTIP and the amended plan was approved by our shareholders on June 29, 2010. The amended LTIP became effective for grants beginning with the 2010 performance year. Under the amended LTIP, the notional units granted to plan participants will have the same characteristics as notional units under the old LTIP. However, the number of notional units that vest will be based, in part, on the total shareholder return of Atlantic Power compared to a group of peer companies in Canada. In addition, vesting of the notional units for officers of Atlantic Power will occur on a three-year cliff basis as opposed to ratable vesting over three years for officers' grants made prior to the amendments.

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

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 the awards granted prior to the 2010 amendment is determined by projecting the total number of notional units that will vest in future periods, including dividends accrued monthly as incremental notional units during the vesting period, and applying the current market price per share to the projected number of notional units that will vest. The fair value of awards granted for the 2010 performance period and after with market vesting conditions is based upon a Monte Carlo simulation model on their grant date. The aggregate number of shares which may be issued from treasury under the amended LTIP is limited to 1,350,000. Unvested notional units are recorded as either a liability or equity award based on management's intended method of redeeming the notional units when they vest.

**Recent Accounting Developments**

*Adopted*

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

In December 2010, the FASB issued changes to the testing of goodwill for impairment. These changes require an entity to perform all steps in the test for a reporting unit whose carrying value is

Table of Contents

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

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

*Issued*

In May 2011, the FASB issued changes to conform existing guidance regarding fair value measurement and disclosure between US GAAP and International Financial Reporting Standards. These changes both clarify the FASB's intent about the application of existing fair value measurement and disclosure requirements and amend certain principles or requirements for measuring fair value or for disclosing information about fair value measurements. The clarifying changes relate to the application of the highest and best use and valuation premise concepts, measuring the fair value of an instrument classified in a reporting entity's shareholders' equity, and disclosure of quantitative information about unobservable inputs used for Level 3 fair value measurements. The amendments relate to measuring the fair value of financial instruments that are managed within a portfolio; application of premiums and discounts in a fair value measurement; and additional disclosures concerning the valuation processes used and sensitivity of the fair value measurement to changes in unobservable inputs for those items categorized as Level 3, a reporting entity's use of a nonfinancial asset in a way that differs from the asset's highest and best use, and the categorization by level in the fair value hierarchy for items required to be measured at fair value for disclosure purposes only. These changes become effective on January 1, 2012. These changes will not have an impact on the consolidated financial statements.

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

Table of Contents

**Consolidated Results of Operations**

The following table and discussion is a summary of our consolidated results of operations for the years ended December 31, 2011, 2010 and 2009. The results of operations by segment are discussed in further detail following this consolidated overview discussion.

| | Year ended December 31, | | | | |
|---|---|---|---|---|---|
| | 2011 | 2010 | 2009 | $ change 2011 vs. 2010 | $ change 2010 vs. 2009 |
| | (in thousands of U.S. dollars) | | | | |
| Project revenue | | | | | |
| Northeast | $ 58,201 | $ 596 | $ | $ 57,605 | $ 596 |
| Southeast | 160,911 | 163,205 | 148,517 | (2,294) | 14,688 |
| Northwest | 8,982 | | | 8,982 | |
| Southwest | 55,501 | 30,318 | 31,000 | 25,183 | (682) |
| Unallocated Corporate and Other | 1,300 | 1,137 | | 163 | 1,137 |
| | 284,895 | 195,256 | 179,517 | 89,639 | 15,739 |
| Project expenses | | | | | |
| Northeast | 44,477 | 443 | | 44,034 | 443 |
| Southeast | 120,024 | 124,755 | 117,484 | (4,731) | 7,271 |
| Northwest | 9,414 | | | 9,414 | |
| Southwest | 36,598 | 10,570 | 11,565 | 26,028 | (995) |
| Unallocated Corporate and Other | 3,950 | 1,409 | | 2,541 | 1,409 |
| | 214,463 | 137,177 | 129,049 | 77,286 | 8,128 |
| Project other income (expense) | | | | | |
| Northeast | (2,785) | 6,841 | 2,596 | (9,626) | 4,245 |
| Southeast | (22,189) | (13,754) | 6,307 | (8,435) | (20,061) |
| Northwest | (430) | 326 | 458 | (756) | (132) |
| Southwest | (11,245) | (9,761) | (11,147) | (1,484) | 1,386 |
| Unallocated Corporate and Other | 196 | 148 | (267) | 48 | 415 |
| | (36,453) | (16,200) | (2,053) | (20,253) | (14,147) |
| Total project income | | | | | |
| Northeast | 10,939 | 6,994 | 2,596 | 3,945 | 4,398 |
| Southeast | 18,698 | 24,696 | 37,340 | (5,998) | (12,644) |
| Northwest | (862) | 326 | 458 | (1,188) | (132) |
| Southwest | 7,658 | 9,987 | 8,288 | (2,329) | 1,699 |
| Unallocated Corporate and Other | (2,454) | (124) | (267) | (2,330) | 143 |
| | 33,979 | 41,879 | 48,415 | (7,900) | (6,536) |
| Administrative and other expenses | | | | | |
| Administration | 38,108 | 16,149 | 26,028 | 21,959 | (9,879) |
| Interest, net | 25,998 | 11,701 | 55,698 | 14,297 | (43,997) |
| Foreign exchange loss (gain) | 13,838 | (1,014) | 20,506 | 14,852 | (21,520) |
| Other (income) expense, net | | (26) | 362 | 26 | (388) |
| Total administrative and other expenses | 77,944 | 26,810 | 102,594 | 51,134 | (75,784) |
| Income (loss) from operations before income taxes | (43,965) | 15,069 | (54,179) | (59,034) | 69,248 |
| Income tax expense (benefit) | (8,324) | 18,924 | (15,693) | (27,248) | 34,617 |
| Net (loss) income | (35,641) | (3,855) | (38,486) | (31,786) | 34,631 |
| Net loss attributable to noncontrolling interest | (480) | (103) | | (377) | (103) |
| Preferred share dividends of a subsidiary company | 3,247 | | | 3,247 | |
| | $ (38,408) | $ (3,752) | $ (38,486) | $ (34,656) | $ 34,734 |

Net (loss) income attributable to Atlantic Power Corporation

Table of Contents

***Consolidated Overview***

We have five reportable segments: Northeast, Southeast, Northwest, Southwest and Un-allocated Corporate. The consolidated results of operations are discussed below by reportable segment. The consolidated results of operation include the results of operation from the Partnership beginning on the acquisition date of November 5, 2011.

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

Significant non-cash items, which are subject to potentially significant fluctuations, include: (1) the change in fair value of certain derivative financial instruments that are required by GAAP to be revalued at each balance sheet date (see "Item 7A. Quantitative and Qualitative Disclosures About Market Risk" for additional information); (2) the non-cash impact of foreign exchange fluctuations from period to period on the U.S. dollar equivalent of our Canadian dollar-denominated obligations; and (3) the related deferred income tax expense (benefit) associated with these non-cash items.

Cash available for distribution was $82.2 million, $65.5 million and $66.3 million for the years ended December 31, 2011, 2010 and 2009, respectively. See "Cash Available for Distribution" for additional information.

Income (loss) from operations before income taxes for the years ended December 31, 2011, 2010 and 2009 was $(44.0) million, $15.1 million and $(54.2) million, respectively. See "Segment Analysis" below for additional information.

***Segment Analysis***

*Northeast*

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

| | Year ended December 31, | | | | |
|---|---|---|---|---|---|
| | 2011 | 2010 | 2009 | % change 2011 vs. 2010 | % change 2010 vs. 2009 |
| **Northeast** | | | | | |
| Project Income | $ 10,939 | $ 6,994 | $ 2,596 | 56% | 169% |

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

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

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

These increases were partially offset by:

- decreased project income of $6.3 million at Chambers primarily attributable to increased operations and maintenance costs incurred in connection with a forced outage during July 2011, lower dispatch compared to 2010 and $3.2 million non-cash adjustment to the project's asset retirement obligation;

Table of Contents

lower project income of $1.4 million at Onondaga Renewables which recorded a $1.5 million asset impairment; and

elimination of project income at Rumford which was sold in 2010 of $1.2 million.

*Year ended December 31, 2010 compared with Year ended December 31, 2009*

Project income for 2010 increased $4.4 million or 169% from 2009 primarily due to:

increased project income of $6.4 million at Chambers due to lower maintenance costs in 2010 compared to 2009, which included a planned steam turbine overhaul, higher dispatch during a warmer summer in 2010 compared to 2009 and a $1.2 million non-cash change in fair value of derivative instruments associated with its interest rate swaps; and

increased project income of $3.1 million at Rumford primarily due to a $1.5 million pre-tax gain on the sale of our equity investment in the project.

These increases were partially offset by:

decreased project income of $1.9 million at Topsham due to a $2.0 million pre-tax long-lived impairment charge; and

decreased project income of $3.2 million at Selkirk primarily attributable to a $2.1 million non-cash change in the fair value of a natural gas contract that is recorded at fair value and lower operations and maintenance expenses.

*Southeast*

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

| | 2011 | 2010 | 2009 | % change 2011 vs. 2010 | % change 2010 vs. 2009 |
|---|---|---|---|---|---|
| **Southeast** | | | | | |
| Project Income | $ 18,698 | $ 24,696 | $ 37,340 | -24% | -34% |

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

Project income for 2011 decreased $6.0 million or 24% from 2010 primarily due to:

decreased project income of $14.9 million at Piedmont due to non-cash change in the fair value of the interest rate swaps related to the project's non-recourse construction financing;

decreased project income of $3.5 million at Orlando primarily due to the non-cash change in fair value of derivative instruments associated with its natural gas swaps as well as higher operations and maintenance expenses resulting from a planned major gas turbine overhaul; and

lower project income of $2.4 million at Pasco due to higher operations and maintenance expenses attributable to the unplanned replacement of gas turbine components and unplanned repairs on the generator and boiler during 2011.

These decreases were partially offset by:

increased project income of $7.9 million at Lake primarily attributable to a decrease of $7.0 million related to the non-cash change in fair value of derivative instruments associated with its natural gas swaps as well as lower fuel expenses attributable to lower prices on natural gas swaps; and

Table of Contents

increased project income of $6.7 million at Auburndale primarily attributable to $2.4 million increased revenue from annual contractual escalation of capacity payments, the decrease of $2.1 million related to the non-cash change in fair value of derivative instruments associated with its natural gas swaps as well as higher dispatch in 2011.

*Year ended December 31, 2010 compared with Year ended December 31, 2009*

Project income for 2010 decreased $12.6 million or 34% from 2009 primarily due to:

decreased project income of $6.3 million at Auburndale due to increase in charge associated with non-cash change in fair value of derivative instruments associated with its natural gas swaps; and

decreased project income of $13.1 million due to the absence of Mid-Georgia during 2010. The Mid-Georgia project was sold in the fourth quarter of 2009.

These decreases were partially offset by:

increased project income of $3.4 million at Lake due to earnings favorable off-peak dispatch during the summer months as well as annual escalation of capacity payments; and

increased project income of $3.3 million at Piedmont due to non-cash change in the fair value of the interest rate swaps related to the project's non-recourse construction financing.

*Northwest*

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

| | Year ended December 31, | | | | |
|---|---|---|---|---|---|
| | 2011 | 2010 | 2009 | % change 2011 vs. 2010 | % change 2010 vs. 2009 |
| **Northwest** | | | | | |
| Project Income (loss) | $ (862) | $ 326 | $ 458 | -364% | -29% |

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

Project income for 2011 decreased $1.2 million or 364% from 2010 primarily due to a $1.6 million project loss at Idaho Wind which became operational in 2011. This was offset by $0.4 million of project income from the newly acquired Frederickson project.

*Year ended December 31, 2010 compared with Year ended December 31, 2009*

Project income in the Northwest segment for the year ended December 31, 2010 did not change significantly from 2009.

*Southwest*

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

| | 2011 | 2010 | 2009 | % change 2011 vs. 2010 | % change 2010 vs. 2009 |
|---|---|---|---|---|---|
| **Southwest** | | | | | |
| Project Income | $ 7,658 | $ 9,987 | $ 8,288 | -23% | 20% |

Table of Contents

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

Project income for 2011 decreased $2.3 million or 23% from 2010 primarily due to:

- decreased project income of $1.6 million at Gregory attributable to higher gas prices due to a favorable gas hedge that expired at the end of 2010;
- decreased project income of $0.7 million at Badger due to lower capacity payments under a new one-year interim power purchase agreement beginning in April 2011; and
- project loss of $1.6 million from the newly acquired Oxnard project.

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

*Year ended December 31, 2010 compared with Year ended December 31, 2009*

Project income for 2010 increased $1.7 million or 20% from 2009 primarily due to the absence of losses from the Stockton project. The Stockton project, which had $2.5 million in losses in 2009, was sold in the fourth quarter of 2009.

*Un-allocated Corporate*

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

| | Year ended December 31, | | | | |
|---|---|---|---|---|---|
| | 2011 | 2010 | 2009 | % change 2011 vs. 2010 | % change 2010 vs. 2009 |
| **Un-Allocated Corporate** | | | | | |
| Project loss | $ (2,454) | $ (124) | $ (267) | 1879% | -54% |
| Administration | 38,108 | 16,149 | 26,028 | 136% | -38% |
| Interest, net | 25,998 | 11,701 | 55,698 | 122% | -79% |
| Foreign exchange loss (gain) | 13,838 | (1,014) | 20,506 | -1465% | -105% |
| Other (income) expense, net | | (26) | 362 | -100% | -107% |
| Total administrative and other expenses | $ 77,944 | $ 26,810 | $ 102,594 | 191% | -74% |
| Income tax expense (benefit) | $ (8,324) | $ 18,924 | $ (15,693) | -144% | -221% |

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

Total administrative and other expenses for 2011 increased $51.1 million or 191% from 2010 primarily due to:

- increased administration expense of $21.7 million primarily due to costs incurred related to the acquisition of the Partnership;
- increased interest expenses of $14.3 million primarily due to issuance of the Senior Notes in the fourth quarter of 2011 as well as debt assumed in our acquisition of the Partnership; and
- increased foreign exchange loss of $14.9 million primarily due to a $17.8 million increase in unrealized losses on foreign exchange forward contracts and an $11.8 million increase in realized losses on foreign exchange contract settlements, offset by a $14.7 million unrealized gain in the revaluation of instruments denominated in Canadian dollars. The U.S. dollar to

Canadian dollar exchange rate increased by 2.3% in 2011 compared to a decrease of 5.7% in 2010.

Table of Contents

Income tax benefit for 2011 was $8.3 million. The difference between the actual tax benefit of $8.3 million and the expected income tax benefit, based on the Canadian enacted statutory rate of 26.5%, of $11.7 million for the year ended December 31, 2011 is primarily due to a $9.4 million increase in the valuation allowance offset by a benefit of $5.6 million related to different tax rates for operating projects in the United States. The income tax expense for 2010 was $18.9 million. The difference between the actual tax expense of $18.9 million and the expected income tax expense, based on the Canadian enacted statutory rate of 28.5%, of $4.3 million for the year ended December 31, 2010 is primarily due to a $12.3 million increase in the valuation allowance and a $1.5 million additional tax expense related to different tax rates for operating projects in the United States.

*Year ended December 31, 2010 compared with Year ended December 31, 2009*

Total administrative and other expenses for 2010 decreased $75.8 million or 74% from 2009 primarily due to:

- decreased management fees of $14.1 million due to a non-cash charge associated with the termination of the management agreements at the end of 2009. Effective December 31, 2009, Atlantic Power Management, LLC no longer provides management and administrative services for our company; and

- decreased interest expenses of $44.0 million due to extinguishment of the subordinated notes that were outstanding and converted to common stock at the end of 2009. In November 2009, we completed our common share conversion, which resulted in the extinguishment of Cdn$347.8 million ($327.7 million) principal value of 11% subordinated notes due 2016 that previously formed a part of each IPS.

- These decreases were partially offset by increased foreign exchanges loss (gain) of $21.5 million due to a decrease in the exchange rate from U.S. dollar to Canadian dollar. The exchange rate decreased by 5.7% in 2010 compared to a decrease of 15.9% in 2009.

Income tax expense for 2010 was $18.9 million. The difference between the actual tax expense of $18.9 million and the expected income tax expense, based on the Canadian enacted statutory rate of 28.5%, of $4.3 million for the year ended December 31, 2010 is primarily due to a $12.3 million increase in the valuation allowance and a $1.5 million additional tax expense related to different tax rates for operating projects in the United States. The income tax benefit for 2009 was $15.7 million. The difference between the actual tax benefit of $15.7 million and the expected income tax benefit, based on the Canadian enacted statutory rate of 30.0%, of $16.2 million for the year ended December 31, 2009 is primarily due to a $22.0 million increase in the valuation allowance offset by recording a $13.2 million deferred tax benefit related to the expected benefit of utilizing a portion of our Canadian net operating losses in 2010 and a $5.4 million additional tax benefit related to different tax rates for operating projects in the United States.

***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.

Table of Contents

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

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

| | Year ended December 31, | | | $ change | |
|---|---|---|---|---|---|
| | **2011** | **2010** | **2009** | **2011 vs 2010** | **2010 vs 2009** |
| **Project Adjusted EBITDA by segment** | | | | | |
| Northeast | $ 59,299 | $ 36,030 | $ 32,435 | $ 23,269 | $ 3,595 |
| Southeast | 79,445 | 78,245 | 75,265 | 1,200 | 2,980 |
| Northwest | 11,363 | 736 | 822 | 10,627 | (86) |
| Southwest | 37,717 | 37,867 | 35,891 | (150) | 1,976 |
| Un-allocated corporate | (2,546) | (294) | (234) | (2,252) | (60) |
| **Total** | 185,278 | 152,584 | 144,179 | 32,694 | 8,405 |
| **Reconciliation to project income** | | | | | |
| Depreciation and amortization | 95,564 | 65,791 | 67,643 | 29,773 | (1,852) |
| Interest expense, net | 27,990 | 23,628 | 31,511 | 4,362 | (7,883) |
| Change in the fair value of derivative instruments | 25,334 | 17,643 | 5,047 | 7,691 | 12,596 |
| Other (income) expense | 2,411 | 3,643 | (8,437) | (1,232) | 12,080 |
| **Project income** | $ 33,979 | $ 41,879 | $ 48,415 | $ (7,900) | $ (6,536) |

*Northeast*

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

| | **2011** | **2010** | **2009** | **% change 2011 vs. 2010** | **% change 2010 vs. 2009** |
|---|---|---|---|---|---|
| **Northeast** | | | | | |
| Project Adjusted EBITDA | $ 59,299 | $ 36,030 | $ 32,435 | 65% | 11% |

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

Project adjusted EBITDA for 2011 increased $23.3 million or 65% from 2010 primarily due to:

increased EBITDA of $8.7 million at Cadillac which was acquired in December 2010;

Table of Contents

increased EBITDA of $1.6 million at Selkirk attributable to higher energy and capacity revenues resulting from the recognition of previously deferred revenue;

EBITDA of $8.2 million at the newly acquired Curtis Palmer project;

EBITDA of $2.8 million at the newly acquired Tunis project; and

EBITDA of $1.9 million at the newly acquired North Bay project.

These increases were partially offset by:

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

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

*Year ended December 31, 2010 compared with Year ended December 31, 2009*

Project adjusted EBITDA for 2010 increased $3.6 million or 11% from 2009 primarily due to increased EBITDA of $5.7 million at Chambers due to lower operations and maintenance costs in 2010 as compared to 2009, which had a planned steam turbine generator overhaul outage, as well as higher generation due to better market prices on the ACE PPA; offset by

decreased EBITDA of $2.6 million due to the absence of Rumford EBITDA as the project was sold in the fourth quarter of 2010 and generated no EBITDA during 2010.

*Southeast*

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

| | 2011 | 2010 | 2009 | % change 2011 vs. 2010 | % change 2010 vs. 2009 |
|---|---|---|---|---|---|
| **Southeast** | | | | | |
| Project Adjusted EBITDA | $ 79,445 | $ 78,245 | $ 75,265 | 2% | 4% |

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

Project adjusted EBITDA for 2011 increased $1.2 million or 2% from 2010 primarily due to increased EBITDA of $4.0 million at Auburndale due to higher dispatch and increased capacity payments under contractual escalation of the PPA.

This increase was partially offset by:

decreased EBITDA of $2.4 million at Pasco due to higher operations and maintenance expenses attributable to the unplanned replacement of gas turbine components and unplanned repairs on the generator and boiler during 2011; and

decreased EBITDA of $1.2 million at Orlando due to higher operations and maintenance expenses resulting from a planned major gas turbine overhaul.

64

Table of Contents

*Year ended December 31, 2010 compared with Year ended December 31, 2009*

Project adjusted EBITDA for 2010 increased $3.0 million or 4% from 2009 primarily due to:

- increased EBITDA of $6.1 million at Lake due to earnings from favorable off-peak dispatch during the summer months of 2010 and increased contractual capacity payments under the project's PPA; and

- increased EBITDA of $1.4 million at Pasco primarily attributable to a maintenance outage during the year ended December 31, 2009.

These increases were partially offset by:

- decreased EBITDA of $1.0 million at Auburndale due to higher maintenance costs in 2010 and a longer scheduled down-time during a planned outage; and

- decreased EBITDA of $2.5 million at Mid-Georgia. Mid-Georgia was sold in the fourth quarter of 2009.

*Northwest*

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

| | 2011 | 2010 | 2009 | 2011 vs. 2010 | 2010 vs. 2009 |
|---|---|---|---|---|---|
| **Northwest** | | | | | |
| Project Adjusted EBITDA | $ 11,363 | $ 736 | $ 822 | 1444% | -10% |

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

Project adjusted EBITDA for 2011 increased $10.6 million or greater than 100% from 2010 primarily due to:

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

- EBITDA of $2.7 million from newly acquired Williams Lake project; and

- EBITDA of $2.1 million from the newly acquired Frederickson project.

*Year ended December 31, 2010 compared with Year ended December 31, 2009*

Project adjusted EBITDA in the Northwest segment for the year ended December 31, 2010 did not change significantly from 2009.

*Southwest*

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

| | Year ended December 31, | | | | |
|---|---|---|---|---|---|
| | 2011 | 2010 | 2009 | % change 2011 vs. 2010 | % change 2010 vs. 2009 |
| **Southwest** | | | | | |
| Project Adjusted EBITDA | $ 37,717 | $ 37,867 | $ 35,891 | 0% | 6% |

Table of Contents

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

Project adjusted EBITDA for 2011 decreased less than 1% from 2010 primarily due to:

- decreased EBITDA of $2.4 million at Badger Creek due to lower capacity payments under the new one year interim power purchase agreement beginning in April 2011; and

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

These decreases were partially offset by:

- EBITDA of $3.6 million from the newly acquired Manchief project.

*Year ended December 31, 2010 compared with Year ended December 31, 2009*

Project adjusted EBITDA for 2010 increased $2.0 million or 6% from 2009 primarily due to:

- increased EBITDA of $1.0 million at Stockton. In 2009, Stockton had an EBITDA loss of $1.0 million and was sold in the fourth quarter of 2009; and

- increased EBITDA of $1.0 million at Path 15 due to lower operations and maintenance expenses.

***Generation and Availability***

| | Year ended December 31, | | | | |
|---|---|---|---|---|---|
| | 2011 | 2010 | 2009 | % change 2011 vs. 2010 | % change 2010 vs. 2009 |
| **Aggregate power generation (Net MWh)** | | | | | |
| Northeast | 1,207,961 | 784,683 | 786,039 | 53.9% | -0.2% |
| Southeast | 1,770,800 | 1,935,649 | 1,848,751 | -8.5% | 4.7% |
| Northwest | 338,678 | 21,418 | 18,087 | 1481.3% | 18.4% |
| Southwest | 877,338 | 643,811 | 819,354 | 36.3% | -21.4% |
| Total | 4,194,777 | 3,385,562 | 3,472,231 | 23.9% | -2.5% |
| **Weighted average availability** | | | | | |
| Northeast | 93.0% | 92.6% | 87.9% | 0.4% | 5.3% |
| Southeast | 98.3% | 95.7% | 98.4% | 2.7% | -2.7% |
| Northwest | 99.7% | 98.8% | 99.8% | 0.9% | -1.0% |
| Southwest | 96.5% | 96.9% | 92.8% | -0.4% | 4.4% |
| Total | 96.5% | 95.3% | 95.1% | 1.3% | 0.2% |

Table of Contents

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

Aggregate power generation for 2011 increased 23.9% from 2010 primarily due to:

- increased generation in the Northeast segment primarily due to 314,211 MWh from newly acquired Partnership projects;

- increased generation in the Northwest segment primarily due to 198,821 MWh from newly acquired Partnership projects as well as generation from Idaho Wind which became operational in the first quarter of 2011; and

- increased generation in the Southwest segment primarily due to 340,498 MWh from newly acquired Partnership projects.

These increases were partially offset by:

- decreased generation in the Southeast segment attributable to the Lake project that dispatched during off-peak hours due to favorable market conditions in 2010 and not in 2011 as well as scheduled major maintenance at the Orlando project during 2011.

*Year ended December 31, 2010 compared with Year ended December 31, 2009*

Aggregate power generation for 2010 decreased 2.5% from 2009 primarily due to:

- decreased generation in the Southwest segment from the absence of the Stockton project which was sold in 2009.

This decrease was partially offset by:

- increased generation in the Southeast segment due primarily to increased generation at Lake associated with dispatch during off-peak hours due to favorable market conditions.

**Consolidated Cash Flows**

At December 31, 2011, cash and cash equivalents increased $15.2 million from December 31, 2010 to $60.7 million. The increase in cash and cash equivalents was due to $55.9 million provided by operating activities and $641.2 million of cash provided by financing activities offset by $682.0 million of cash used for investing activities.

At December 31, 2010, cash and cash equivalents decreased $4.4 million from December 31, 2009 to $45.5 million. The decrease in cash and cash equivalents was due to $147.0 million used in investing activities offset by $87.0 million provided by operating activities and $55.7 million of cash provided by financing activities.

| | | | | $ Change | |
|---|---|---|---|---|---|
| | **2011** | **2010** | **2009** | **2011 vs. 2010** | **2010 vs. 2009** |
| Net cash provided by operating activities | $ 55,935 | $ 86,953 | $ 50,449 | $ (31,018) | $ 36,504 |
| Net cash (used in) provided by investing activities | (682,008) | (146,997) | 24,958 | (535,011) | (171,955) |
| Net cash (used in) provided by financing activities | 641,227 | 55,691 | (62,884) | 585,536 | 118,575 |

***Operating Activities***

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

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

Cash flow from operating activities increased by $36.5 million for the year ended December 31, 2010 over the comparable period in 2009. The change from the prior year is primarily attributable to a significant decrease in cash interest expense as a result of our common share conversion in November 2009, which eliminated Cdn$347.8 million ($327.7 million) of outstanding subordinated notes, as well as higher net cash tax refunds of $8.0 million. The positive change in operating cash flow attributable to the reduced interest expense was partially offset by a $5.8 million decrease in distributions from our Orlando project and no distributions in 2010 from our Selkirk project, both of which are equity method investments. The decrease in distributions from Orlando was the result of a one-time receipt of insurance proceeds in 2009 related to an unplanned outage that occurred in 2008.

***Investing Activities***

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

Cash flows used in investing activities for the year ended December 31, 2011 were $682.0 million compared to cash flows used in investing activities of $147.0 million for the year ended December 31, 2010. The change is due to the $579.1 million cash paid for the Partnership acquisition net of cash acquired. We also invested $118.1 million in 2011 for the construction-in-progress for our Piedmont biomass project.

Cash flows used in investing activities for the year ended December 31, 2010 were $147.0 million compared to cash flows provided by investing activities of $25.0 million for the year ended December 31, 2009. We acquired a 27.6% equity interest in Idaho Wind for $38.9 million and approximately $3.1 million in transaction costs. In addition, we loaned $22.8 million to Idaho Wind to temporarily fund a portion of construction costs at the project. We acquired 100% interest of Cadillac Renewable Energy for $36.6 million and assumed $43.1 million in non-recourse project-level debt. We invested $47.7 million for the construction-in-progress for our Piedmont biomass project.

***Financing Activities***

Cash provided by financing activities for the year ended December 31, 2011 resulted in a net inflow of $641.2 million compared to a net inflow of $55.7 million for the same period in 2010. The change from the prior year is primarily attributable to $438.0 million in net proceeds from our issuance of Senior Notes in November 2011 and $155.4 million in net proceeds from our equity offering in October 2011 to fund a portion of the cash portion of the Partnership acquisition. In 2011, we also received proceeds of $100.8 million of project-level debt related to our Piedmont biomass construction

Table of Contents

project and borrowed $58.0 million from our credit facility. This was offset by a $20.0 million increase in dividends paid.

Cash provided by financing activities for the year ended December 31, 2010 resulted in a net inflow of $55.7 million compared to a net outflow of $62.9 million for the same period in 2009. The change from the prior year is primarily attributable to $72.8 million in net proceeds from our equity offering and $74.6 million in net proceeds from the issuance of convertible debentures, offset by a $40.0 million increase in dividends paid and a $6.1 million increase in project-level debt payments. We completed our common share conversion in November 2009. As a result, Cdn$347.8 million ($327.7 million) of subordinated notes were extinguished and our entire monthly distribution to shareholders is now paid in the form of a dividend as opposed to the monthly distribution being split between a subordinated notes interest payment and a common share dividend during the year ended December 31, 2009.

**Cash Available for Distribution**

Prior to our conversion to a common share structure, holders of our IPSs received monthly cash distributions in the form of interest payments on subordinated notes and dividends on common shares. Subsequent to the conversion, holders of common shares received the same monthly cash distributions of Cdn$1.094 per year in the form of a dividend on the new common shares. The dividend was increased to Cdn$1.15 in November 2011. The payout ratio was 105%, 100% and 88% for the years ended December 31, 2011, 2010 and 2009, respectively.

The payout ratio of 105% for the year ended December 31, 2011 is close to the range we had expected prior to the acquisition of the Partnership and includes approximately two months of combined results. The increase in the payout ratios from 2009 through 2011 was anticipated. We expect a material decline in the 2012 payout ratio due to a number of factors including:

- a full year's impact of the Partnership acquisition;
- increases in cash flow from our legacy portfolio of projects such as Selkirk whose project level debt will be repaid by mid-year 2012 and Chambers where we expect a resolution of the dispute with the host over electrical pricing;
- a one-time realized gain from the termination of foreign currency forwards based on combined entities' aggregate position; and
- the lower final termination payment from our prior management agreement with an Arclight affiliate.

Table of Contents

The table below presents our calculation of cash available for distribution for the years ended December 31, 2011, 2010 and 2009:

| (unaudited) (in thousands of U.S. dollars, except as otherwise stated) | Year ended December 31, 2011 | 2010 | 2009 |
|---|---|---|---|
| Cash flows from operating activities | $ 55,935 | $ 86,953 | $ 50,449 |
| Project-level debt repayments | (21,589) | (18,882) | (12,744) |
| Interest on IPS portion of subordinated notes[1] | | | 30,639 |
| Purchases of property, plant and equipment[2] | (2,035) | (2,549) | (2,016) |
| Transaction costs[3] | 33,402 | | |
| Realized foreign currency losses on hedges associated with the Partnership transaction | 16,492 | | |
| Cash Available for Distribution[5] | 82,205 | 65,522 | 66,328 |
| Interest on subordinated notes | | | 30,639 |
| Dividends on common shares | 86,357 | 65,648 | 27,988 |
| Total dividends declared to shareholders | $ 86,357 | $ 65,648 | $ 58,627 |
| Payout ratio | 105% | 100% | 88% |
| *Expressed in Cdn$* | | | |
| Cash Available for Distribution | 81,363 | 67,540 | 75,673 |
| Total dividends declared to shareholders | 85,437 | 67,914 | 66,325 |

(1) Prior to the common share conversion in November 2009, a portion of our monthly distribution to IPS holders was paid in the form of interest on the subordinated notes comprising a part of the IPSs. Subsequent to the conversion, the entire monthly cash distribution is paid in the form of a dividend on our common shares.

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

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

(4) 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.

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

**Liquidity and Capital Resources**

***Overview***

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

Table of Contents

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.

With the exception of our equity contribution of an additional $147 million towards the construction of the Canadian Hills project and our commitment to the final construction of Piedmont Green Power, we do not expect any material unusual requirements for cash outflows for 2012 for capital expenditures or other required investments. In addition, there are no debt instruments with significant maturities or refinancing requirements in 2012.

***Senior Credit Facility***

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

The credit facility contains representations, warranties, terms and conditions customary for credit facilities of this type. We must meet certain financial covenants under the terms of the credit facility, which are generally based on ratios of debt to EBITDA and EBITDA to interest. The credit facility is secured by pledges of certain assets and interests in certain subsidiaries. We expect to remain in compliance with the covenants of the credit facility for at least the next 12 months.

As of February 24, 2012, $72.8 million has been drawn under the credit facility and the applicable margin was 2.75%. As of February 24, 2012, $106.7 million was issued in letters of credit, but not drawn, to support contractual credit requirements at several of our projects, which includes the newly acquired projects from the Partnership acquisition.

***Notes of Atlantic Power Corporation***

On November 4, 2011, we completed a private placement of US$460.0 million aggregate principal amount of 9.0% senior notes due 2018 (the "Atlantic Notes" or "Senior Notes") to qualified institutional buyers in reliance on Rule 144A under the Securities Act of 1933, as amended (the "Securities Act"'), and to non-U.S. persons outside of the United States in compliance with Regulation S under the Securities Act. The Senior Notes were issued at an issue price of 97.471% of the face amount of the Senior Notes for aggregate gross proceeds to us of $448.0 million. The Atlantic Notes are senior unsecured obligations, guaranteed by certain of our subsidiaries.

***Notes of the Partnership***

The Partnership, a wholly-owned subsidiary acquired on November 5, 2011, has outstanding Cdn$210.0 million ($206.5 million at December 31, 2011) 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.

Table of Contents

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

Atlantic Power (US) GP, an indirect, wholly-owned subsidiary acquired in connection with the acquisition of the Partnership, has outstanding $150.0 million aggregate principal amount of 5.87% senior guaranteed notes, Series A, due August 2017 (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 2019 (the "Series B Notes"). Interest on the Series B Notes is payable semi-annually at 5.97%. Pursuant to the terms of the Series A Notes and the Series B Notes, we must meet certain financial and other covenants, including a financial covenant generally based on the ratio of debt to capitalization of the Partnership and Atlantic Power (US) GP. The Series A Notes and the Series B Notes are guaranteed by the Partnership and by Curtis Palmer LLC.

***Notes of Curtis Palmer LLC***

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

***Convertible Debentures***

In October 2006, we issued, in a public offering, Cdn$60 million aggregate principal amount of 6.25% convertible secured debentures, which we refer to as the 2006 Debentures, for gross proceeds of $52.8 million. The 2006 Debentures pay interest semi-annually on April 30 and October 31 of each year. The Debentures initially had a maturity date of October 31, 2011 and are convertible into approximately 80.6452 common shares per Cdn$1,000 principal amount of 2006 Debentures, at any time, at the option of the holder, representing a conversion price of Cdn$12.40 per common share. The 2006 Debentures are secured by a subordinated pledge of our interest in certain subsidiaries and contain certain restrictive covenants. In connection with our conversion to a common share structure on November 27, 2009, the holders of the 2006 Debentures approved an amendment to increase the annual interest rate from 6.25% to 6.50% and separately, an extension of the maturity date from October 2011 to October 2014. During fiscal year 2010 and fiscal year 2011 through February 24, 2012, Cdn$4.2 million and Cdn$10.9 million of the 2006 Debentures, respectively, were converted to 0.3 million and 0.8 million common shares, respectively. As of February 24, 2012 the 2006 Debentures balance is Cdn$44.9 million ($44.7 million).

In December 2009, we issued, in a public offering, Cdn$86.25 million aggregate principal amount of 6.25% convertible unsecured subordinated debentures, which we refer to as the 2009 Debentures, for gross proceeds of $82.1 million. The 2009 Debentures pay interest semi-annually on March 15 and September 15 of each year beginning September 15, 2010. The 2009 Debentures mature on March 15, 2017 and are convertible into approximately 76.9231 common shares per Cdn$1,000 principal amount of 2009 Debentures, at any time, at the option of the holder, representing a conversion price of Cdn$13.00 per common share. During fiscal year 2010 and fiscal year 2011 through February 24, 2012, Cdn$3.1 million and Cdn$15.7 million of the 2009 Debentures, respectively, were converted to 0.2 million and 1.2 million common shares, respectively. As of February 24, 2012 the 2009 Debentures balance is Cdn$67.4 million ($67.2 million).

In October 2010, we issued, in a public offering, Cdn$80.5 million aggregate principal amount of 5.60% convertible unsecured subordinated debentures, which we refer to as the 2010 Debentures, for gross proceeds of $78.9 million. The 2010 Debentures pay interest semi-annually on June 30 and December 30 of each year beginning June 30, 2011. The 2010 Debentures mature on June 30, 2017,

Table of Contents

unless earlier redeemed. The debentures are convertible into our common shares at an initial conversion rate of 55.2486 common shares per Cdn$1,000 principal amount of debentures, representing an initial conversion price of approximately Cdn$18.10 per common share. As of February 24, 2012 the 2010 debentures balance is Cdn$80.5 million ($80.3 million).

***Preferred shares issued by a subsidiary company***

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

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

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.

***Project-Level Debt***

The following table summarizes the maturities of project-level debt. The amounts represent our share of the non-recourse project-level debt balances at December 31, 2011 and exclude any purchase accounting adjustments recorded to adjust the debt to its fair value at the time the project was acquired. Certain of the projects have more than one tranche of debt outstanding with different maturities, different interest rates and/or debt containing variable interest rates. Project-level debt agreements contain covenants that restrict the amount of cash distributed by the project if certain debt service coverage ratios are not attained. As of December 31, 2011, the covenants at the Selkirk, Gregory, Delta-Person and at Epsilon Power Partners are temporarily preventing those projects from making cash distributions to us. We expect to resume receiving distributions from Selkirk in 2012, Gregory and Delta-Person in 2014 and Epsilon Power Partners in 2013. All project-level debt is non-recourse to us and substantially the entire principal is amortized over the life of the projects' PPAs. The non-recourse holding company debt relating to our investment in Chambers is held at Epsilon Power Partners, our wholly-owned subsidiary. For the year ended December 31, 2011, we have contributed approximately $0.48 million to Epsilon Power Partners for debt service payments on the

Table of Contents

holding company debt but do not anticipate any additional required contributions to Epsilon. In February 2012 Chambers failed one of its debt covenants and subsequently received a waiver from the creditors on February 24, 2012.

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

| | Range of Interest Rates | Total Remaining Principal Repayments | 2012 | 2013 | 2014 | 2015 | 2016 | Thereafter |
|---|---|---|---|---|---|---|---|---|
| **Consolidated Projects:** | | | | | | | | |
| Epsilon Power Partners | 7.40% | $ 34,982 | $ 1,500 | $ 3,000 | $ 5,000 | $ 5,750 | $ 6,000 | $ 13,732 |
| Piedmont[1] | 3.8% 5.2% | 100,796 | | 55,357 | 4,789 | 4,772 | 3,690 | 32,188 |
| Path 15 | 7.9% 9.0% | 145,880 | 8,667 | 9,402 | 8,065 | 8,749 | 9,487 | 101,510 |
| Auburndale | 5.10% | 11,900 | 7,000 | 4,900 | | | | |
| Cadillac | 6.02% 8.00% | 40,231 | 3,791 | 2,400 | 2,000 | 2,500 | 2,500 | 27,040 |
| Curtis Palmer[2] | 5.9% | 190,000 | | | 190,000 | | | |
| Total Consolidated Projects | | 523,789 | 20,958 | 75,059 | 209,854 | 21,771 | 21,677 | 174,470 |
| **Equity Method Projects:** | | | | | | | | |
| Chambers | 1.70% 5.50% | 64,103 | 12,176 | 10,783 | 5,780 | 5,213 | 5,447 | 24,704 |
| Delta-Person | 2.00% | 9,392 | 1,212 | 1,300 | 1,394 | 1,495 | 1,604 | 2,387 |
| Selkirk | 9.00% | 5,845 | 5,845 | | | | | |
| Gregory | 2.10% 7.50% | 12,571 | 1,801 | 2,007 | 2,170 | 2,268 | 2,448 | 1,877 |
| Rockland | 1.10% 6.30% | 39,288 | 13,617 | 368 | 445 | 529 | 583 | 23,746 |
| Idaho Wind | 2.80% 6.60% | 50,894 | 2,058 | 2,198 | 2,364 | 2,554 | 2,511 | 39,209 |
| Total Equity Method Projects | | 182,093 | 36,709 | 16,656 | 12,153 | 12,059 | 12,593 | 91,923 |
| Total Project-Level Debt | | $ 705,882 | $ 57,667 | $ 91,715 | $ 222,007 | $ 33,830 | $ 34,270 | $ 266,393 |

(1) As of December 31, 2011 the inception to date balance of $100.8 million on the Piedmont construction debt is funded by the related bridge loan of $51.0 million and $49.8 million funded by the construction loan that will convert to a term loan. The terms of the Piedmont project-level debt financing include a $51.0 million bridge loan for approximately 95.0% of the stimulus grant expected to be received from the U.S. Treasury 60 days after the start of commercial operations, and an $82.0 million construction term loan. The $51.0 million bridge loan will be repaid in early 2013 and repayment of the expected $82.0 million term loan will commence in 2013.

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

***Restricted Cash***

The projects with project-level debt generally have reserve requirements to support payments for major maintenance costs and project-level debt service. For projects that are consolidated, our share of these amounts is reflected as restricted cash on the consolidated balance sheet. At December 31, 2011, restricted cash at the consolidated projects totaled $21.4 million.

**Capital Expenditures**

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

Table of Contents

In 2012, several of our projects will conduct scheduled outages to complete major maintenance work. The level of maintenance and capital expenditures for our legacy portfolio of projects will be consistent with prior years. However, overall maintenance and capital expenditures will be higher than in 2011 due to our acquisition of the Partnership project portfolio. During the fourth quarter of 2011 the level of maintenance was substantial and capital expenditures were minimal which is customary. A planned outage occurred at Nipigon and unplanned outages occurred at North Island and Oxnard in the fourth quarter. In July, Chambers was offline due to a forced outage associated with a leak in its steam turbine. The project completed repairs in July and despite the outage, by maintaining a high availability factor earned its full capacity payment. Cadillac conducted its scheduled fall outage in September that consisted of equipment inspections and minor boiler repairs. The maintenance outage was completed on time and slightly under budget. Cadillac's outage of six days will not impact its availability requirement under the project's PPA. North Island underwent an outage to refurbish part of its gas turbine and Oxnard's outage was related to a lubrication system repair. Nipigon's gas turbine was removed for maintenance. At each of North Island, Oxnard and Nipigon, the facility's gas turbine was removed and replaced with a lease engine, pursuant to a lease agreement with GE, in order to minimize the plant's downtime. As a result, availability targets under each plant's PPA were met.

In 2011, we incurred approximately $113.5 million in capital expenditures for the construction of our Piedmont biomass project. In 2012, we expect to incur approximately $35.2 million in capital expenditures related to the Piedmont project, with total project costs through expected completion in late 2012 of approximately $207.0 million. The project is funded with an $82.0 million construction loan which will convert to a term loan upon commercial operation, a $51.0 million bridge loan and approximately $75.0 million of equity contributed by Atlantic Power. The bridge loan will be repaid from the proceeds of a federal stimulus grant which is expected to be received two months after achieving commercial operation.

**Contractual Obligations and Commercial Commitments**

The following table summarizes our contractual obligations as of December 31, 2011 (in thousands of U.S. dollars):

| | 2011 | | | | |
|---|---|---|---|---|---|
| | **Less than 1 year** | **1 3 Years** | **3 5 Years** | **Thereafter** | **Total** |
| Long-term debt including estimated interest(1) | $ 192,911 | $ 655,128 | $ 1,085,009 | $ 652,485 | $ 2,585,533 |
| Operating leases | 1,149 | 1,965 | 1,037 | 907 | 5,058 |
| Operations and maintenance commitments | 5,592 | 3,790 | 772 | 2,541 | 12,695 |
| Fuel purchase and transportation obligations | 67,712 | 189,966 | 80,961 | 51,777 | 390,416 |
| Construction obligations | 22,618 | | | | 22,618 |
| Interconnection obligations | 3,510 | 8,455 | 7,831 | 14,413 | 34,209 |
| Other liabilities | 3,118 | 3,118 | 2,700 | 898 | 9,834 |
| Total contractual obligations | $ 296,610 | $ 862,422 | $ 1,178,310 | $ 723,021 | $ 3,060,363 |

(1) Debt represents our consolidated share of project long-term debt and corporate-level debt. The amount presented excludes the net unamortized purchase price adjustment of $10.6 million related to the fair value of debt assumed in the Path 15 acquisition. 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, 2011 was 3.80% to 9.00%.

(2) The natural gas transportation contracts are based on estimates subject to changes in regulated rates for transportation and have expiry terms ranging from 2012 to 2017

Table of Contents

**Off-Balance Sheet Arrangements**

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

## 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 commodity prices, currency exchange rates or interest rates. Our views on market risk are not necessarily indicative of actual results that may occur and do not represent the maximum possible gains and losses that may occur, since actual gains and losses will differ from those estimated based on actual fluctuations in fuel commodity prices, currency exchange rates or interest rates and the timing of transactions.

**Fuel Commodity Market Risk**

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

The Tunis project is exposed to changes in natural gas prices under a combination of spot purchases and short-term contracts expiring in 2014. In 2012, projected cash distributions at Tunis would change by approximately $2.8 million per $1.00/Mmbtu change in the price of natural gas based on the current level natural gas volumes used by the project.

The operating margin at our 50% owned Orlando project is exposed to changes in natural gas prices following the expiration of its fuel contract at the end of 2013. In the third quarter of 2010, we entered into natural gas swaps in order to effectively fix the price of 1.2 million Mmbtu of future natural gas purchases representing approximately 25% of our share of the expected natural gas purchases at the project during 2014 and 2015. In the third quarter of 2011, we entered into additional natural gas swaps for 2014 and 2015 increasing the total to 2.0 million Mmbtu or approximately 40% of our share of expected natural gas purchases for that period. We also entered into natural gas swaps to effectively fix the price of 1.3 million Mmbtu of future natural gas purchases representing approximately 25% of our share of the expected natural gas purchases at the project during 2016 and 2017.

We expect cash distributions from Orlando to increase significantly following the expiration of the project's gas contract at the end of 2013 because both projected natural gas prices at that time and the prices in the natural gas swaps we have executed are lower than the price of natural gas being purchased under the project's gas contract.

The Lake project's operating margin is exposed to changes in the market price of natural gas from the expiration of its natural gas supply contract on June 30, 2009 through to the expiration of its PPA on July 31, 2013 not passed through in their PPAs. The Auburndale project purchases natural gas under a fuel supply agreement which provides approximately 80% of the project's fuel requirements at fixed prices through June 30, 2012. The remaining 20% is purchased at market prices and therefore the project is exposed to changes in natural gas prices for that portion of its gas requirements through the

Table of Contents

termination of the fuel supply agreement and 100% of its natural gas requirements from the expiration of the fuel contract in mid-2012 until the termination of its PPA at the end of 2013.

In 2012, projected cash distributions at Auburndale would change by approximately $0.4 million per $1.00/Mmbtu change in the price of natural gas based on the current level of un-hedged natural gas volumes at the project. In 2012, projected cash distributions at Lake would change by approximately $0.8 million per $1.00/Mmbtu change in the price of natural gas based on the current level of un-hedged natural gas volumes at the project.

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

The following table summarizes the hedge position related to natural gas needed to meet PPA requirements at Lake and Auburndale as of December 31, 2011 and February 24, 2012:

| | 2012 | 2013 |
|---|---|---|
| Portion of gas volumes currently hedged: | | |
| Lake: | | |
| Contracted | | |
| Financially hedged | 90% | 83% |
| Total | 90% | 83% |
| Auburndale: | | |
| Contracted | 40% | |
| Financially hedged | 32% | 79% |
| Total | 72% | 79% |
| Average price of financially hedged volumes (per Mmbtu) | | |
| Lake | $ 6.90 | $ 6.63 |
| Auburndale | $ 6.51 | $ 6.92 |

**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 but we pay dividends to shareholders and interest on corporate-level long-term debt and on convertible debentures predominantly in Canadian dollars. We have a hedging strategy for the purpose of mitigating the currency risk impact on the long-term sustainability of dividends to shareholders. We have executed this strategy utilizing cash flows from our projects that generate Canadian dollars and by entering into forward contracts to purchase Canadian dollars at a fixed rate to hedge approximately 99% of our expected dividend, long-term debt and convertible debenture interest payments through 2015. Changes in the fair value of the forward contracts partially offset foreign exchange gain or losses on the U.S. dollar equivalent of our Canadian dollar obligations. At December 31, 2011, the forward contracts consist of (1) monthly purchases through the end of 2013 of Cdn$6.0 million at an exchange rate of Cdn$1.134 per U.S. dollar and (2) contracts assumed in our acquisition of the Partnership with various expiration dates through December 2015 to purchase a total of Cdn$215.5 million at an average exchange rate of Cdn$1.134 per U.S. dollar. It is our intention to periodically consider extending or terminating the length of these forward contracts.

Table of Contents

On January 4, 2012, we terminated various foreign currency forward contracts with expiration dates through December 2013 assumed in our acquisition of the Partnership resulting in a realized gain of $9.6 million.

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

The following table contains the components of recorded foreign exchange (gain) loss for the years ended December 31, 2011, 2010 and 2009:

| | Year ended December 31, | | |
|---|---|---|---|
| | **2011** | **2010** | **2009** |
| Unrealized foreign exchange (gain) loss: | | | |
| Convertible debentures | $ (5,574) | $ 9,153 | $ 55,508 |
| Forward contracts and other | 14,211 | (3,542) | (31,138) |
| | 8,637 | 5,611 | 24,370 |
| Realized foreign exchange loss (gains) on forward contract settlements | 5,201 | (6,625) | (3,864) |
| | $ 13,838 | $ (1,014) | $ 20,506 |

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

| | |
|---|---|
| Canadian dollar denominated debt, at carrying value | (39,606) |
| Foreign currency forward contracts | 34,867 |

**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 88% of our debt, including our share of the project-level debt associated with equity investments in affiliates, either bears interest at fixed rates or is financially hedged through the use of interest rate swaps.

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

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

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

Table of Contents

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

After considering the impact of interest rate swaps, a hypothetical change in the average interest rate of 100 basis points would change annual interest costs, including interest at equity investments, by approximately $2.1 million.

## 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 Interim 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 Securities Exchange Act of 1934, 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 Annual Report on Internal Control over Financial Reporting

Management's Report on Internal Control over Financial Reporting is included in Part II, Item 15 of this annual report on Form 10-K beginning on page F-2.

(c) Attestation Report of the Registered Public Accounting Firm

The effectiveness of our internal control over financial reporting as of December 31, 2011 has been audited by KPMG LLP, an independent registered public accounting firm, as stated in their report, which is included in Part II, Item 15 of this annual report Form 10-K on page 80.

(d) Changes in Internal Control over Financial Reporting

There have been no changes in integral controls over financial reporting during the fourth quarter of 2011, that have materially affected, or are reasonably likely to materially affect, the Company's internal control over financial reporting. The Company acquired Capital Power Income L.P. on November 5, 2011 and management excluded from its assessment of the effectiveness of the Company's internal control over financial reporting as of December 31, 2011.

## ITEM 9B. OTHER INFORMATION

None.

Table of Contents

## 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.

### 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.

## 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. Individual financial statements of Chambers Cogeneration Limited Partnership were included in Atlantic Power's Annual Report on Form 10-K for the year-ended December 31, 2010 pursuant to the requirements of Rule 3-09 of Regulation S-X. In 2011, Chambers Cogeneration Limited Partnership recorded material adjustments to the previously filed financial statements to correct errors made related to the recognition of depreciation expense and asset retirement obligation accretion expense. The adjustments made to the Chambers Cogeneration Limited Partnership financial statements did not have a material effect on the financial statements of Atlantic Power. As Chambers Cogeneration Limited Partnership is not an accelerated filer, to the extent Chambers Cogeneration Limited Partnership is determined to have been a significant subsidiary of Atlantic Power during any of 2009, 2010 or 2011, the separate financial statements required by Rule 3-09 of Regulation S-X will b filed on Form 10-K/A as promptly as possible.

Table of Contents

(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) |
| 4.6 | 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) |
| 4.7 | First Supplemental Indenture, dated as of November 5, 2011 (incorporated by reference to our Current Report on Form 8-K filed on November 7, 2011) |
| 4.8 | Second Supplemental Indenture, dated as of November 5, 2011 (incorporated by reference to our Current Report on Form 8-K filed on November 7, 2011) |
| 4.9 | 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) |
| 10.1* | Amended and Restated Senior Secured Credit Agreement dated November 4, 2011 among Atlantic Power Corporation and Bank of Montreal, Union Bank, Toronto Dominion and Morgan Stanley. |

Table of Contents

| Exhibit No. | Description |
|---|---|
| 10.2 | Employment Agreement, dated as of December 31, 2009 between Atlantic Power Corporation and Barry Welch (incorporated by reference to our registration statement on Form 10-12B filed on April 13, 2010) |
| 10.3 | Employment Agreement, dated as of December 31, 2009 between Atlantic Power Corporation and Paul Rapisarda (incorporated by reference to our registration statement on Form 10-12B filed on April 13, 2010) |
| 10.4 | 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) |
| 10.5 | Third Amended and Restated Long-Term Incentive Plan (incorporated by reference to our registration statement on Form 10-12B filed on July 9, 2010) |
| 10.6* | Fourth Amended and Restated Long-Term Incentive Plan |
| 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 (incorporated by reference to our registration statement on Form 10-12B filed on April 13, 2010) |
| 31.1* | Certification of Chief Executive Officer pursuant to Rule 13a-14(a)/15d-14(a) under the Securities Exchange Act of 1934 |
| 31.2* | Certification of Chief Financial Officer pursuant to Rule 13a-14(a)/15d-14(a) under the Securities Exchange Act of 1934 |
| 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, 2011 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. |

* Filed herewith.

** Furnished herewith.

(b) Exhibits:

See Item 15(a)(3) above.

(c) Financial Statement Schedules:

See Item 15(a)(2) above.

Table of Contents

## 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, 2012

Atlantic Power Corporation

By: /s/ LISA J. DONAHUE

Name: Lisa J. Donahue
Title: *Interim Chief Financial 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, 2012 |
| /s/ LISA J. DONAHUE<br>Lisa J. Donahue | Interim Chief Financial Officer (principal financial and accounting officer) | February 27, 2012 |
| /s/ IRVING R. GERSTEIN<br>Irving R. Gerstein | Chairman of the Board | February 27, 2012 |
| /s/ KENNETH M. HARTWICK<br>Kenneth M. Hartwick | Director | February 27, 2012 |
| /s/ R. FOSTER DUNCAN<br>R. Foster Duncan | Director | February 27, 2012 |
| /s/ JOHN A. MCNEIL<br>John A. McNeil | Director | February 27, 2012 |
| /s/ HOLLI LADHANI<br>Holli Ladhani | Director | February 27, 2012 |

Table of Contents

**Atlantic Power Corporation**
**Index to Consolidated Financial Statements**

Table of Contents

## Managements' Reports to Shareholders of Atlantic Power Corporation

### Management's Report on Financial Statements and Practices

The accompanying Consolidated Financial Statements of Atlantic Power Corporation (the "Company") 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 the 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.

### Management's Report on Internal Control over Financial Reporting

Management is responsible for establishing and maintaining adequate internal control over financial reporting for the Company. In order to evaluate the effectiveness of internal control over financial reporting, as required by Section 404 of the Sarbanes-Oxley Act, management has conducted an assessment, including testing, using the criteria in *Internal Control Integrated Framework*, issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO). The Company's system of internal control over financial reporting is 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. The Company's internal control over financial reporting includes those policies and procedures that (i) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of the assets of the Company; (ii) 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 (iii) 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.

Based on the assessment, management has concluded that the Company maintained effective internal control over financial reporting as of December 31, 2011, based on criteria in *Internal Control Integrated Framework* issued by the COSO.

The Company acquired Capital Power Income L.P. during 2011, and management excluded from its assessment of the effectiveness of the Company's internal control over financial reporting as of December 31, 2011, Capital Power Income L.P.'s internal control over financial reporting associated with total assets of $2.2 billion and total revenues of $74 million included in the consolidated financial statements of Atlantic Power Corporation and subsidiaries as of and for the year ended December 31, 2011.

The effectiveness of the Company's internal control over financial reporting as of December 31, 2011 has been audited by KPMG LLP, an independent registered public accounting firm, as stated in their report, which is included herein.

/s/ BARRY E. WELCH

Barry E. Welch
*Chief Executive Officer*

/s/ LISA J. DONAHUE

Lisa J. Donahue
*Interim Chief Financial Officer*

Table of Contents

**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, 2011, 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 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, 2011, based on criteria established in *Internal Control  Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission.

Atlantic Power Corporation acquired Capital Power Income L.P. during 2011, and management excluded from its assessment of the effectiveness of Atlantic Power Corporation's internal control over financial reporting as of December 31, 2011, Capital Power Income L.P.'s internal control over financial reporting associated with total assets of $2.2 billion and total revenues of $74 million included in the consolidated financial statements of Atlantic Power Corporation and subsidiaries as of and for the year ended December 31, 2011. Our audit of internal control over financial reporting of Atlantic Power Corporation also excluded an evaluation of the internal control over financial reporting of Capital Power Income L.P.

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, 2011 and 2010, and the related consolidated statements of operations, shareholders' equity and cash flows for each of the years in the two-year period ended December 31, 2011, and our report dated February 29, 2012 expressed an unqualified opinion on those consolidated financial statements.

/s/ KPMG LLP

New York, New York
February 29, 2012

Table of Contents

**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, 2011 and 2010, and the related consolidated statements of operations, shareholders' equity and cash flows for each of the years in the two-year period ended December 31, 2011. 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, 2011 and 2010, and the results of their operations and their cash flows for each of the years in the two-year period ended December 31, 2011, 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, 2011, 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 29, 2012 expressed an unqualified opinion on the effectiveness of the Company's internal control over financial reporting.

/s/ KPMG LLP

New York, New York
February 29, 2012

Table of Contents

**Report of Independent Registered Public Accounting Firm**

The Board of Directors
Atlantic Power Corporation

We have audited the accompanying consolidated balance sheet of Atlantic Power Corporation as of December 31, 2009 and the related consolidated statements of operations, shareholders' equity and cash flows for the year then ended. In connection with our audits of the consolidated financial statements, we also have audited financial statement "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 statements presentation. We believe that our audits provide a reasonable basis for our opinion.

As discussed in Note 2 to the consolidated financial statements on January 1, 2009, Atlantic Power Corporation adopted FASB's ASC 805 Business Combinations. In our opinion the consolidated financial statements referred to above present fairly, in all material respects, the financial position of Atlantic Power Corporation as of December 31, 2009 and the results of its operations and its cash flows the year then ended., 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, present fairly, in all material respects, the information set forth therein.

/s/ KPMG LLP

Chartered Accountants, Licensed Public Accountants

Toronto, Canada

April 12, 2010, except as to notes 4, 8 and 17, which are as of May 26, 2010, Notes 2(a) and 16 which are as of June 16, 2010 and as to Note 19 which is as of February 27, 2012.

Table of Contents

**ATLANTIC POWER CORPORATION**

**CONSOLIDATED BALANCE SHEETS**

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

| | December 31, 2011 | December 31, 2010 |
|---|---|---|
| **Assets** | | |
| Current assets: | | |
| Cash and cash equivalents | $ 60,651 | $ 45,497 |
| Restricted cash | 21,412 | 15,744 |
| Accounts receivable | 79,008 | 19,362 |
| Note receivable related party (Note 20) | | 22,781 |
| Current portion of derivative instruments asset (Notes 11 and 12) | 10,411 | 8,865 |
| Inventory (Note 5) | 18,628 | 5,498 |
| Prepayments and other | 7,615 | 2,982 |
| Refundable income taxes (Note 13) | 3,042 | 1,593 |
| Total current assets | 200,767 | 122,322 |
| Property, plant, and equipment, net (Note 6) | 1,388,254 | 271,830 |
| Transmission system rights (Note 7) | 180,282 | 188,134 |
| Equity investments in unconsolidated affiliates (Note 4) | 474,351 | 294,805 |
| Other intangible assets, net (Note 7) | 584,274 | 88,462 |
| Goodwill (Note 7) | 343,586 | 12,453 |
| Derivative instruments asset (Notes 11 and 12) | 22,003 | 17,884 |
| Other assets | 54,910 | 17,122 |
| Total assets | $ 3,248,427 | $ 1,013,012 |
| **Liabilities** | | |
| Current Liabilities: | | |
| Accounts payable | $ 18,122 | $ 8,608 |
| Accrued interest | 19,916 | 3,975 |
| Other accrued liabilities | 43,968 | 11,025 |
| Revolving credit facility (Note 9) | 58,000 | |
| Current portion of long-term debt (Note 9) | 20,958 | 21,587 |
| Current portion of derivative instruments liability (Notes 11 and 12) | 20,592 | 10,009 |
| Dividends payable | 10,733 | 6,154 |
| Other current liabilities | 165 | 5 |
| Total current liabilities | 192,454 | 61,363 |
| Long-term debt (Note 9) | 1,404,900 | 244,299 |
| Convertible debentures (Note 10) | 189,563 | 220,616 |
| Derivative instruments liability (Notes 11 and 12) | 33,170 | 21,543 |
| Deferred income taxes (Note 13) | 182,925 | 29,439 |
| Power purchase and fuel supply agreement liabilities, net (Note 7) | 71,775 | |
| Other non-current liabilities (Note 8) | 57,859 | 2,376 |
| Commitments and contingencies (Note 21) | | |
| Total liabilities | 2,132,646 | 579,636 |
| **Equity** | | |
| Common shares, no par value, unlimited authorized shares; 113,526,182 and 67,118,154 issued and outstanding at December 31, 2011 and 2010, respectively | 1,217,265 | 626,108 |
| Preferred shares issued by a subsidiary company (Note 17) | 221,304 | |
| Accumulated other comprehensive income (loss) | (5,193) | 255 |
| Retained deficit | (320,622) | (196,494) |

| | | |
|---|---|---|
| Total Atlantic Power Corporation shareholders' equity | 1,112,754 | 429,869 |
| Noncontrolling interest | 3,027 | 3,507 |
| Total equity | 1,115,781 | 433,376 |
| Total liabilities and equity | $ 3,248,427 | $ 1,013,012 |

See accompanying notes to consolidated financial statements.

Table of Contents

**ATLANTIC POWER CORPORATION**

**CONSOLIDATED STATEMENTS OF OPERATIONS**

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

| | Years ended December 31, | | |
|---|---|---|---|
| | **2011** | **2010** | **2009** |
| Project revenue: | | | |
| Energy sales | $ 106,062 | $ 69,116 | $ 58,953 |
| Energy capacity revenue | 131,362 | 93,567 | 88,449 |
| Transmission services | 30,087 | 31,000 | 31,000 |
| Other | 17,384 | 1,573 | 1,115 |
| | 284,895 | 195,256 | 179,517 |
| Project expenses: | | | |
| Fuel | 93,993 | 65,553 | 59,522 |
| Operations and maintenance | 56,832 | 31,237 | 28,153 |
| Depreciation and amortization | 63,638 | 40,387 | 41,374 |
| | 214,463 | 137,177 | 129,049 |
| Project other income (expense): | | | |
| Change in fair value of derivative instruments (Notes 11 and 12) | (22,776) | (14,047) | (6,813) |
| Equity in earnings of unconsolidated affiliates (Note 4) | 6,356 | 13,777 | 8,514 |
| Gain on sales of equity investments, net (Note 4) | | 1,511 | 13,780 |
| Interest expense | (20,053) | (17,660) | (18,800) |
| Other income, net | 20 | 219 | 1,266 |
| | (36,453) | (16,200) | (2,053) |
| Project income | 33,979 | 41,879 | 48,415 |
| Administrative and other expenses (income): | | | |
| Administration | 38,108 | 16,149 | 26,028 |
| Interest, net | 25,998 | 11,701 | 55,698 |
| Foreign exchange loss (gain) (Note 12) | 13,838 | (1,014) | 20,506 |
| Other (income) expense, net | | (26) | 362 |
| | 77,944 | 26,810 | 102,594 |
| Income (loss) from operations before income taxes | (43,965) | 15,069 | (54,179) |
| Income tax expense (benefit) (Note 13) | (8,324) | 18,924 | (15,693) |
| Net loss | (35,641) | (3,855) | (38,486) |
| Net loss attributable to noncontrolling interest | (480) | (103) | |
| Net income attributable to Preferred share dividends of a subsidiary company | 3,247 | | |
| Net loss attributable to Atlantic Power Corporation | $ (38,408) | $ (3,752) | $ (38,486) |
| Net loss per share attributable to Atlantic Power Corporation shareholders: (Note 18) | | | |
| Basic | $ (0.50) | $ (0.06) | $ (0.63) |
| Diluted | $ (0.50) | $ (0.06) | $ (0.63) |
| Weighted average number of common shares outstanding: (Note 18) | | | |
| Basic | 77,466 | 61,706 | 60,632 |
| Diluted | 77,466 | 61,706 | 60,632 |

See accompanying notes to consolidated financial statements.

Table of Contents

**ATLANTIC POWER CORPORATION**

**CONSOLIDATED STATEMENTS OF SHAREHOLDERS' EQUITY**

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

| | Common Shares (Shares) | Common Shares (Amount) | Retained Deficit | Accumulated Other Comprehensive Income | Noncontrolling Interest | Preferred Shares | Total Shareholders' Equity |
|---|---|---|---|---|---|---|---|
| December 31, 2008 | 60,941 | $ 215,163 | $ (60,401) | $ (3,136) | $ | $ | $ 151,626 |
| Subordinated notes conversion | (114) | 327,691 | | | | | 327,691 |
| Common shares issued for LTIP | 59 | 151 | | | | | 151 |
| Common stock repurchases | (482) | (1,088) | | | | | (1,088) |
| Dividends declared | | | (28,054) | | | | (28,054) |
| Comprehensive Income: | | | | | | | |
| Net loss | | | (38,486) | | | | (38,486) |
| Unrealized loss on hedging activities, net of tax of ($1,518) | | | | 2,277 | | | 2,277 |
| Net comprehensive loss | | | | | | | (36,209) |
| December 31, 2009 | 60,404 | 541,917 | (126,941) | (859) | | | 414,117 |
| Convertible debenture conversion | 579 | 7,147 | | | | | 7,147 |
| Common shares issuance, net of costs | 6,029 | 75,267 | | | | | 75,267 |
| Common shares issued for LTIP | 106 | 1,325 | | | | | 1,325 |
| LTIP amendment | | 2,952 | | | | | 2,952 |
| Piedmont equity costs | | (2,500) | | | | | (2,500) |
| Noncontrolling interest | | | | | 3,507 | | 3,507 |
| Dividends declared | | | (65,801) | | | | (65,801) |
| Comprehensive Income: | | | | | | | |
| Net loss | | | (3,752) | | | | (3,752) |
| Unrealized loss on hedging activities, net of tax of ($1,518) | | | | 1,114 | | | 1,114 |
| Net comprehensive loss | | | | | | | (2,638) |
| December 31, 2010 | 67,118 | 626,108 | (196,494) | 255 | 3,507 | | 433,376 |
| Convertible debenture conversion | 2,090 | 26,357 | | | | | 26,357 |
| Common shares issuance, net of costs | 12,650 | 155,424 | | | | | 155,424 |
| Common shares issued for LTIP | 168 | 1,951 | | | | | 1,951 |
| Shares issued in connection with Partnership acquisition | 31,500 | 407,425 | | | | | 407,425 |
| Preferred shares of a subsidiary company assumed in connection with Partnership acquisition | | | | | | 221,304 | 221,304 |
| Noncontrolling interest | | | | | (480) | | (480) |
| Dividends declared on common shares | | | (85,720) | | | | (85,720) |
| Dividends declared on preferred shares of a subsidiary company | | | | | | (3,247) | (3,247) |
| Comprehensive Income: | | | | | | | |
| Net (loss) income | | | (38,408) | | | 3,247 | (35,161) |
| Unrealized loss on hedging activities, net of tax of $251 | | | | (1,638) | | | (1,638) |
| Foreign currency translation adjustments | | | | (3,321) | | | (3,321) |
| Defined benefit plan, net of $264 tax | | | | (489) | | | (489) |
| Net comprehensive loss | | | | | | | (40,609) |

| | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|
| December 31, 2011 | 113,526 | $ | 1,217,265 | $ | (320,622) | $ | (5,193) | $ | 3,027 | $ | 221,304 | $ | 1,115,781 |

See accompanying notes to consolidated financial statements.

Table of Contents

**ATLANTIC POWER CORPORATION**

**CONSOLIDATED STATEMENTS OF CASH FLOWS**

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

| | Years ended December 31, | | |
|---|---|---|---|
| | 2011 | 2010 | 2009 |
| Cash flows from operating activities: | | | |
| Net loss | $ (35,641) | $ (3,855) | $ (38,486) |
| Adjustments to reconcile to net cash provided by operating activities: | | | |
| Depreciation and amortization | 63,638 | 40,387 | 41,374 |
| Common share conversions recorded in interest expense | | | 4,508 |
| Subordinated note redemption premium recorded in interest expense | | | 1,935 |
| Long-term incentive plan expense | 3,167 | 4,497 | |
| Gain on sale of assets | | (1,511) | (12,847) |
| Earnings from unconsolidated affiliates | (7,878) | (16,913) | (14,213) |
| Impairment of equity investments | 1,522 | 3,136 | 5,500 |
| Distributions from unconsolidated affiliates | 21,889 | 16,843 | 27,884 |
| Unrealized foreign exchange loss | 8,636 | 5,611 | 24,370 |
| Change in fair value of derivative instruments | 22,776 | 14,047 | 6,813 |
| Change in deferred income taxes | (9,908) | 17,964 | (6,436) |
| Other | | (210) | 106 |
| Change in other operating balances | | | |
| Accounts receivable | (15,563) | 1,729 | 10,520 |
| Prepayments, refundable income taxes and other assets | 1,653 | 9,311 | (3,454) |
| Accounts payable and accrued liabilities | 4,931 | (6,551) | 2,959 |
| Other liabilities | (3,287) | 2,468 | (84) |
| Net cash provided by operating activities | 55,935 | 86,953 | 50,449 |
| Cash flows (used in) provided by investing activities: | | | |
| Acquisitions and investments, net of cash acquired | (591,583) | (78,180) | (3,068) |
| Proceeds from (loan to) Idaho Wind | 22,781 | (22,781) | |
| Change in restricted cash | (5,668) | 945 | 575 |
| Biomass development costs | (931) | (2,286) | |
| Proceeds from sale of assets | 8,500 | 2,000 | 29,467 |
| Purchase of property, plant and equipment | (115,107) | (46,695) | (2,016) |
| Net cash (used in) provided by investing activities | (682,008) | (146,997) | 24,958 |
| Cash flows (used in) provided by financing activities: | | | |
| Proceeds from issuance of long term debt | 460,000 | | |
| Proceeds from issuance of equity, net of offering costs | 155,424 | 72,767 | |
| Proceeds from issuance of convertible debenture, net of offering costs | | 74,575 | |
| Deferred financing costs | (26,373) | (7,941) | |
| Repayment of project-level debt | (21,589) | (18,882) | (12,744) |
| Proceeds from revolving credit facility borrowings | 58,000 | 20,000 | |
| Repayments of revolving credit facility borrowings | | (20,000) | (55,000) |
| Dividends paid | (85,029) | (65,028) | (24,955) |
| Equity contribution from noncontrolling interest | | 200 | |
| Proceeds from issuance of project level debt | 100,794 | | 78,330 |
| Redemption of IPSs under normal course issuer bid | | | (3,369) |
| Redemption of subordinated notes | | | (40,638) |
| Costs associated with common share conversion | | | (4,508) |
| Net cash provided by (used in) financing activities | 641,227 | 55,691 | (62,884) |
| Net (decrease) increase in cash and cash equivalents | 15,154 | (4,353) | 12,523 |
| Cash and cash equivalents at beginning of year | 45,497 | 49,850 | 37,327 |
| Cash and cash equivalents at end of year | $ 60,651 | $ 45,497 | $ 49,850 |

| | | | | | | |
|---|---|---|---|---|---|---|
| Supplemental cash flow information | | | | | | |
| Interest paid | $ | 40,238 | $ | 26,687 | $ | 69,186 |
| Income taxes paid (refunded), net | $ | 1,109 | $ | (8,000) | $ | (216) |
| Accruals for capital expenditures | $ | 4,095 | $ | | $ | |

See accompanying notes to consolidated financial statements.

**ATLANTIC POWER CORPORATION**

**NOTES TO CONSOLIDATED FINANCIAL STATEMENTS**

**1. Nature of business**

***General***

Atlantic Power Corporation ("Atlantic Power") is a power generation and infrastructure company with a portfolio of assets in the United States and Canada. Our power generation projects sell electricity to utilities and other large commercial customers under long-term power purchase agreements, which seek to minimize exposure to changes in commodity prices. The net generating capacity of our projects is approximately 2,140 MW, consisting of interests in 31 operational power generation projects across 11 states in the United States and two provinces in Canada, one 53 MW biomass project under construction in Georgia, and an 84 mile, 500-kilovolt electric transmission line located in California. Atlantic Power also owns a majority interest in Rollcast Energy, a biomass power plant developer with several projects under development

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 TSX 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 200 Clarendon Street, Floor 25, Boston, Massachusetts, 02116 USA. Our telephone number in Boston is (617) 977-2400 and the address of our website is www.atlanticpower.com. We make available, free of charge, on our website our Annual Report on Form 10-K, Quarterly Reports on Form 10-Q, Current Reports on Form 8-K, and amendments to those reports filed or furnished pursuant to Section 13(a) or 15(d) of the 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.

**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 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 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)**

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

(c) Restricted cash:

Restricted cash represents cash and cash equivalents that are maintained by the Projects to support payments for major maintenance costs and meet project level 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 five to 28 years. The net carrying amount of deferred financing costs recorded in other assets on the consolidated balance sheets was $40.7 million and $16.7 million at December 31, 2011 and 2010, respectively. Amortization expense for the years ended December 31, 2011, 2010 and 2009 was $1.3 million, $1.2 million, and $14.6 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. As major maintenance occurs and parts are replaced on the plant's combustion and steam turbines, maintenance costs are either expensed or transferred to property, plant and equipment if the maintenance extends the useful lives of the major parts. These costs are depreciated over the parts' estimated useful lives, which is generally three to six years, depending on the nature of maintenance activity performed.

(g) Transmission system rights:

Transmission system rights are an intangible asset that represents the long-term right to approximately 72% of the capacity of the Path 15 transmission line in California. Transmission system rights are amortized on a straight-line basis over 30 years, the regulatory life of Path 15.

(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.

Table of Contents

**ATLANTIC POWER CORPORATION**

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

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

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

Long-lived assets, such as property, plant and equipment, transmission system rights and other intangible assets and liabilities subject to depreciation and amortization, are reviewed for impairment whenever events or changes in circumstances indicate that the carrying amount of an asset may not be recoverable. 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 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. 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, failure of cash flow coverage ratio tests included in project-level non-recourse debt 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.

(j) Distributions from equity method investments: