

ATLANTIC POWER CORP
Form S-1/A
September 17, 2010

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As filed with the Securities and Exchange Commission on September 17, 2010

Registration No. 333-168855

**UNITED STATES
SECURITIES AND EXCHANGE COMMISSION**
WASHINGTON, D.C. 20549

**AMENDMENT NO. 2
TO
FORM S-1**
REGISTRATION STATEMENT UNDER THE SECURITIES ACT OF 1933

ATLANTIC POWER CORPORATION

(Exact Name of Registrant as Specified in Its Charter)

British Columbia, Canada
(State or Other Jurisdiction of
Incorporation or Organization)

4900
(Primary Standard Industrial
Classification Code Number)
200 Clarendon St., Floor 25
Boston, Massachusetts 02116
(617) 977-2400

55-0886410
(I.R.S. Employer
Identification Number)

(Address, Including Zip Code, and Telephone Number, Including
Area Code, of Registrant's Principal Executive Offices)

Barry E. Welch
President and Chief Executive Officer
Atlantic Power Corporation
200 Clarendon St., Floor 25
Boston, Massachusetts 02116
(617) 977-2400

(Name, Address, Including Zip Code, and Telephone Number, Including Area Code, of Agent For Service)

Copies to:

Laura Hodges Taylor, Esq.
Yoel Kranz, Esq.
Goodwin Procter LLP
Exchange Place
Boston, Massachusetts 02109
(617) 570-1000

Christopher J. Cummings, Esq.
Shearman & Sterling LLP
Commerce Court West, Suite 4405
Toronto, Ontario
Canada M5L 1E8
(416) 360-8484

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Approximate date of commencement of proposed sale to the public: As soon as practicable after this Registration Statement becomes effective.

If any of the securities being registered on this Form are to be offered on a delayed or continuous basis pursuant to Rule 415 under the Securities Act of 1933, check the following box:

If this Form is filed to register additional securities for an offering pursuant to Rule 462(b) under the Securities Act, check the following box and list the Securities Act registration statement number of the earlier effective registration statement for the same offering.

If this Form is a post-effective amendment filed pursuant to Rule 462(c) under the Securities Act, check the following box and list the Securities Act registration statement number of the earlier effective registration statement for the same offering.

If this Form is a post-effective amendment filed pursuant to Rule 462(d) under the Securities Act, check the following box and list the Securities Act registration statement number of the earlier effective registration statement for the same offering.

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 definition of "larger accelerated filer," "accelerated filer" and "smaller reporting company" in Rule 12b-2 of the Exchange Act. (Check one):

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

The registrant hereby amends this registration statement on such date or dates as may be necessary to delay its effective date until the registrant shall file a further amendment which specifically states that this registration statement shall thereafter become effective in accordance with Section 8(a) of the Securities Act of 1933, as amended, or until this registration statement shall become effective on such date as the Securities and Exchange Commission, acting pursuant to said Section 8(a), may determine.

EXPLANATORY NOTES

This Registration Statement contains both a United States prospectus (the "U.S. Prospectus") and a prospectus to be used in connection with offering the securities registered hereby in Canada (the "Canadian Prospectus"). The U.S. Prospectus and the Canadian Prospectus are identical in all material respects, except for the front cover page and certain other pages, and except that the Canadian Prospectus includes a "Certificate of the Company" and a "Certificate of the Underwriter." The complete U.S. Prospectus is included herein and is followed by those pages to be used solely in the Canadian Prospectus. Each of the alternate pages for the Canadian Prospectus included herein is labeled "Alternate Page for Canadian Prospectus."

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The information in this prospectus is not complete and may be changed. We may not sell these securities until the registration statement filed with the Securities and Exchange Commission is effective. This preliminary prospectus is not an offer to sell these securities and we are not soliciting offers to buy these securities in any jurisdiction where the offer or sale is not permitted.

PRELIMINARY PROSPECTUS Subject to Completion September 17, 2010

4,500,000 Shares

Common Shares

We are offering 4,500,000 common shares, no par value per share.

Our common shares are listed on the New York Stock Exchange under the symbol "AT" and on the Toronto Stock Exchange under the symbol "ATP." On September 14, 2010, the last reported sale price of our common shares on the New York Stock Exchange and the Toronto Stock Exchange was \$13.27 and Cdn\$13.64, respectively, per share.

Investing in our common shares involves a high degree of risk. Before buying any shares you should carefully read the discussion of material risks of investing in our common shares under the heading "Risk factors" beginning on page 10 of this prospectus.

Neither the Securities and Exchange Commission nor any state securities commission has approved or disapproved of these securities or determined if this prospectus is truthful or complete. Any representation to the contrary is a criminal offense.

	Per Share	Total
Public offering price	\$	\$
Underwriting discounts and commissions	\$	\$
Proceeds, before expenses, to us	\$	\$

The underwriters may also purchase up to an additional 675,000 common shares from us at the public offering price, less the underwriting discounts and commissions payable by us to cover over-allotments, if any, within 30 days from the date of this prospectus.

The underwriters are offering the common shares as set forth under "Underwriting." Delivery of the common shares will be made on or about _____, 2010.

UBS Investment Bank

The date of this prospectus is

, 2010

BMO Capital Markets

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You should rely only on information contained in this document or to which we have referred you. We have not, and our underwriters have not, authorized anyone to provide any information or to make any representations other than those contained in this prospectus or in any free writing prospectuses we have prepared. If anyone provides you with different or inconsistent information, you should not rely on it. We take no responsibility for, and can provide no assurance as to the reliability of, any other information that others may give you. We are not, and the underwriters are not, making an offer to sell the securities in any jurisdiction where the offer or sale is not permitted. This document may only be used where it is legal to sell these securities.

As used in this prospectus, 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. This prospectus includes our trademarks and other trade names identified herein. All other trademarks and trade names appearing in this prospectus are the property of their respective holders.

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Prospectus summary

The following summary may not contain all the information that may be important to you or that you should consider before deciding to purchase any common shares and is qualified in its entirety by the more detailed information appearing elsewhere in this prospectus. You should read the entire prospectus, especially the risks set forth under the heading "Risk factors" in this prospectus, as well as the financial and other information included herein, before making an investment decision.

ATLANTIC POWER CORPORATION

Atlantic Power Corporation is an independent power producer, with power projects located in major markets in the United States. Our current portfolio consists of interests in 12 operational power generation projects across eight states, one wind project under construction, a 500 kilovolt 84-mile electric transmission line located in California, and six development projects in five states. Our power generation projects have an aggregate gross electric generation capacity of approximately 1,823 megawatts (or "MW") in which our ownership interest is approximately 808 MW.

The following map shows the location of our projects, including joint venture interests, across the United States:

We sell the capacity and power from our power generation projects under power purchase agreements (or "PPAs") with a variety of utilities and other parties. Under the PPAs, which have expiration dates ranging from 2010 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 and/or other forms of thermal energy from a number of our projects under energy sales agreements to industrial purchasers ("steam sales agreements"). 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 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 most of the PPAs and steam sales agreements provide for the pass-through or indexing of fuel costs to our customers.

We partner with recognized leaders in the independent power business to operate and maintain our projects, including Caithness Energy, LLC ("Caithness"), Power Plant Management Services 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.

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Atlantic Power Corporation is organized under the laws of the Province of British Columbia. Our registered office is located at 355 Burrard Street, Suite 1900, Vancouver, British Columbia, Canada V6C 2G8 and our headquarters are located at 200 Clarendon Street, Floor 25, Boston, Massachusetts, USA 02116. Our telephone number is (617) 977-2400. Our website address is www.atlanticpower.com. Information contained on, or otherwise accessible through, our website is not incorporated into, and does not constitute a part of, this prospectus or any other report or documents we file with or furnish to the SEC.

We completed our initial public offering on the Toronto Stock Exchange, or the TSX, in November 2004. At the time of the initial public offering, our publicly-traded security was an "income participating security," or "IPS," each of which was comprised of one common share and Cdn\$5.767 principal value of 11% subordinated notes due 2016. On November 27, 2009, our shareholders approved a conversion from the IPS structure to a traditional common share structure. Each IPS has been 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 shares trade on the TSX under the symbol "ATP" and began trading on the New York Stock Exchange, or the NYSE, under the symbol "AT" on July 23, 2010.

OUR COMPETITIVE STRENGTHS

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

- > ***Diversified projects.*** Our power generation projects are diversified by geographic location, electricity and steam customers, and project operators. These projects are generally located in deregulated and more liquid electricity markets or regions of relatively high electricity demand growth.
- > ***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 include Progress Energy Florida, Inc., Tampa Electric Company and Atlantic City Electric.
- > ***Leading third-party managers.*** Our power generation projects rely on a number of different operators for their operation, which are generally recognized leaders in the independent power business. Affiliates of Caithness, Power Plant Management Services and Babcock and Wilcox Power Generation Group, Inc. are our primary project operators.
- > ***Stability of project cash flow.*** Each of our power generation projects currently in operation has been in operation for over ten years. Cash flows from each project are generally supported by energy sales contracts with investment-grade utilities and other sophisticated counterparties.

OUR OBJECTIVES AND BUSINESS STRATEGIES

Our objectives include maintaining the stability and sustainability of dividends to shareholders and to maximize the value of our company. In order to achieve these objectives, we intend to focus on enhancing the operating and financial performance of the projects and on pursuing additional acquisitions primarily in the electric power industry in the U.S. and Canada.

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Organic growth

We intend to enhance the operation and financial performance of our projects through:

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

Successfully extending PPAs and fuel agreements may facilitate refinancings that provide capital to fund growth opportunities.

Extending PPAs following their expiration

PPAs in our portfolio have expiration dates ranging from 2010 to 2037. In each case, we plan for expirations by evaluating various options in the market for maximizing project cash flows. New arrangements may involve responses to utility solicitations for capacity and energy, direct negotiations with the original purchasing utility for PPA extensions, 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 pricing 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 be required in the United States and Canada over the next several years as a result of growth in electricity demand, transmission constraints and the retirement of older generation projects due to obsolescence or environmental concerns. There is also a very active secondary market for existing projects. We intend to expand our operations by making accretive acquisitions with a focus on power generation, transmission, distribution 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 additional investments in development stage projects or companies where the prospects for creating long-term predictable cash flows are attractive. Since the time of our initial public offering on the TSX in 2004, we have twice acquired the interest of another partner in one of our existing projects and will continue to look for such opportunities.

Our senior management has significant experience in the independent power industry and we believe the experience, reputation and industry relationships of our management team will provide us with enhanced access to future acquisition opportunities.

RECENT DEVELOPMENTS

On July 2, 2010, we acquired a 27.6% equity interest in Idaho Wind Partners 1, LLC ("Idaho Wind") for approximately \$40 million. Idaho Wind recently commenced construction of a 183 MW wind power project located near Twin Falls, Idaho, which is currently scheduled to be completed in late 2010 or early 2011. Idaho Wind has 20-year fixed-price PPAs with Idaho Power Company. Our investment in Idaho Wind was funded with cash on hand and a \$20 million borrowing under our senior credit facility. Upon completion of construction, we expect Idaho Wind to provide after-tax cash flows to us of \$4.5 million to \$5.5 million for each full year of operations. Our investment in Idaho Wind will be accounted for under the equity method of accounting.

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In April 2010, our majority-owned subsidiary, Rollcast Energy, Inc., entered into a construction agreement for a 53.5 MW biomass project, known as Piedmont Green Power, to be located in Barnesville, Georgia. Pursuant to the terms of our investment in Rollcast, we have the option, but not the obligation, to invest directly in biomass power plants under development by Rollcast. We currently expect to invest up to \$75 million in the Piedmont Green Power project, representing substantially all of the equity interests in the project. We intend to use a sole arranger to syndicate project level debt financing for the project. Construction of the project is scheduled to commence upon the closing of construction financing early in the fourth quarter of 2010. The Piedmont Green Power project has a 20-year PPA with Georgia Power Company which includes an adjustment related to the cost of biomass fuel for the plant.

Concurrently with this offering, we are offering Cdn\$50,000,000 in aggregate principal amount of our % Series B convertible unsecured subordinated debentures due . The debentures will be convertible into our common shares at the option of the holder at any time prior to the close of business on the earlier of and the business day immediately preceding the date specified by us for redemption of the debentures.

The completion of this offering of common shares is not subject to the completion of the concurrent offering of convertible debentures and the completion of the concurrent offering of convertible debentures is not subject to the completion of this offering. See "Description of concurrent offering of convertible debentures."

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OUR POWER PROJECTS

The following table outlines our portfolio of power generating and transmission assets in operation and under construction as of September 14, 2010, including our interest in each facility. Management believes the portfolio is well diversified in terms of electricity and steam buyers, fuel type, regulatory jurisdictions and regional power pools, thereby partially mitigating exposure to market, regulatory or environmental conditions specific to any single region.

Project name	Location (state)	Type	Total MW	Economic interest(1)	Accounting treatment(2)	Net MW(3)	Electricity purchaser	Power contract expiry	Customer S&P credit rating
Auburndale	Florida	Natural Gas	155	100.00%	C	155	Progress Energy Florida	2013	BBB+
Lake	Florida	Natural Gas	121	100.00%	C	121	Progress Energy Florida	2013	BBB+
Pasco	Florida	Natural Gas	121	100.00%	C	121	Tampa Electric Co.	2018	BBB
Chambers	New Jersey	Coal	262	40.00%	E	89 ⁽⁴⁾	ACE	2024	BBB
						16	DuPont	2024	A
Path 15	California	Transmission	N/A	100.00%	C	N/A	California Utilities via California Independent System Operator ⁽⁵⁾	N/A ⁽⁶⁾	BBB+ to A ⁽⁷⁾
Orlando	Florida	Natural Gas	129	50.00%	E	46	Progress Energy Florida	2023	BBB+
						19	Reedy Creek Improvement District	2013 ⁽⁸⁾	A ⁽⁹⁾
Selkirk	New York	Natural Gas	345	17.70% ⁽¹⁰⁾	E	14	Merchant	N/A	N/R
						47	Consolidated Edison	2014	A-
Gregory	Texas	Natural Gas	400	17.10%	E	59	Fortis Energy Marketing and Trading	2013	A-
						9	Sherwin Alumina	2020	NR
Topsham ⁽¹¹⁾	Maine	Hydro	14	50.00%	E	7	Central Maine Power	2011	BBB+
Badger Creek	California	Natural Gas	46	50.00%	E	23	Pacific Gas & Electric	2011	BBB-

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Rumford	Maine	Coal/Biomass	85	26.40%	E	22	Rumford Paper Co.	2010	N/R
Koma Kulshan	Washington	Hydro	13	49.80%	E	6	Puget Sound Energy	2037	BBB
Delta-Person	New Mexico	Natural Gas	132	40.00%	E	53	PNM	2020	BB-
Idaho Wind ⁽¹²⁾	Idaho	Wind	183	27.57%	E	51	Idaho Power Co.	2030	BBB

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

(2) *Accounting Treatment: C Consolidated; and E Equity Method of Accounting (for additional details, see Note 2 of the accompanying consolidated financial statements for the year ended December 31, 2009).*

(3) *Represents our interest in each project's electric generation capacity based on our economic interest.*

(4) *Includes separate power sales agreement in which the project and ACE share profits on spot sales of energy and capacity not purchased by ACE under the base PPA.*

(footnotes continued on following page)

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- (5) *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 FERC approved annual revenue requirement.*
- (6) *Path 15 is a FERC regulated asset with a FERC-approved regulatory life of 30 years: through 2034.*
- (7) *Largest payers of fees supporting Path 15's annual revenue requirement are PG&E (BBB+), SoCal Ed (BBB+) and SDG&E (A). The California Independent System Operator imposes minimum credit quality requirements for any participants of A or better unless collateral is posted per the imposed schedule.*
- (8) *Upon the expiry of the Reedy Creek PPA, the associated capacity and energy will be sold to PEF.*
- (9) *Fitch rating on Reedy Creek Improvement District bonds.*
- (10) *Represents our residual interest in the project after all priority distributions are paid, which is estimated to occur in 2012.*
- (11) *We own our interest in this project as a lessor.*
- (12) *Project currently under construction and is expected to be completed in late 2010 or early 2011.*

SUMMARY RISK FACTORS

An investment in our common shares involves material risks, including those we have highlighted below. You should consider carefully the risks described below and under "Risk Factors" before purchasing our common shares in this offering:

- > Our revenues depend on our power purchase agreements and we may be adversely affected if these agreements expire or terminate.
- > We are dependent on our power generation projects and our transmission project for virtually all cash available for dividends and may be affected by the profitability of our projects.
- > Each of our power generation projects depends on their customers for a substantial portion of its revenues and we may be adversely affected if these customers do not make required payments.
- > Certain of our power generation projects are exposed to fluctuations in the price of electricity which affect their revenues.
- > Fuel costs may affect profitability of our power generation projects.
- > Our projects and operations are subject to various energy, environmental and other laws and regulations by federal and state agencies.
- > We face increasing competition, which may adversely affect our performance and the performance of our projects.
- > We are exposed to currency exchange rate risks because our revenues and most of our expenses are denominated in U.S. dollars and our payments to shareholders and debenture holders are denominated in Canadian dollars.
- >

Our projects may not operate as planned.

>

Future dividends are not guaranteed.

>

We have limited control over management decisions at certain projects.

>

Financing arrangements could negatively impact our business.

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THE COMMON SHARES

Issuer	Atlantic Power Corporation, a British Columbia corporation.
Common shares to be offered by us	4,500,000 shares.
Common shares to cover over-allotments	We have granted the underwriters an option to purchase up to 675,000 additional common shares to cover over-allotments.
Common shares to be outstanding after this offering	65,012,343 shares (or 65,687,343 shares if the underwriters exercise their over-allotment option in full).
Risk factors	Prospective purchasers should carefully review and evaluate certain risk factors relating to an investment in the common shares, including, but not limited to trading market for common shares and discretion in the use of proceeds. See "Risk factors."
United States and Canadian federal income tax considerations	You should consult your tax advisor with respect to the U.S. and Canadian federal income tax consequences of owning the common shares in light of your own particular situation and with respect to any tax consequences arising under the laws of any state, local, foreign or other taxing jurisdiction. See "Certain United States federal income tax considerations" and "Certain Canadian federal income tax considerations."
Concurrent public offering of convertible debentures	Concurrently with this offering, we are also conducting a separate public offering of Cdn\$50,000,000 in aggregate principal amount of our convertible unsecured subordinated debentures (plus up to an additional Cdn\$7,500,000 in aggregate principal amount of our convertible debentures that we may issue and sell upon the exercise of the underwriter's option to purchase additional convertible debentures). This offering is not conditioned upon the successful completion of the concurrent offering of convertible debentures and the concurrent offering of convertible debentures is not conditioned upon the successful completion of this offering. See "Description of concurrent offering of convertible debentures."

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Use of proceeds	We expect to receive net proceeds from this offering of approximately \$55.9 million after deducting the underwriting discount and our estimated expenses (or approximately \$64.4 million if the underwriters exercise their option to purchase additional shares in full). We intend to use the net proceeds from this offering, along with the net proceeds we receive from our concurrent offering of convertible debentures, for (i) repayment of approximately \$20 million borrowed under our revolving credit facility in June 2010 to partially fund our previously-announced acquisition of a 27.6% equity interest in Idaho Wind Partners 1, LLC, and (ii) to fund an investment of up to \$75 million in the Piedmont Green Power biomass project in Barnesville, Georgia for substantially all of the equity interest in the project. Any remaining net proceeds will be used to fund additional growth opportunities and for general corporate purposes.
Conflicts of interest	As described in "Use of proceeds," some of the net proceeds of this offering may be used to pay down borrowings under our credit facility. Because more than 5% of the proceeds of this offering, not including underwriting compensation, may be received by affiliates of the underwriters in this offering, this offering is being conducted in compliance with NASD Rule 2720, as administered by the Financial Industry Regulatory Authority. Pursuant to that rule, the appointment of a qualified independent underwriter is not necessary in connection with this offering, as the offering is of a class of equity securities for which a "bona fide public market," as defined by the Financial Industry Regulatory Authority rules, exists as of the date of the filing of the registration statement and as of the effective date thereof.
Listing	Our outstanding common shares are listed on the TSX under the symbol "ATP" and on the New York Stock Exchange under the symbol "AT."
The number of common shares to be outstanding after this offering is based upon 60,512,343 shares outstanding as of September 14, 2010. The number of common shares to be outstanding after this offering does not include:	
>	582,000 unvested notional units granted under the terms of our Long Term Incentive Plan;
>	11,471,055 shares issuable upon conversion, redemption, purchase for cancellation or maturity of our outstanding convertible debentures; and
>	any shares reserved for issuance upon the conversion, redemption, purchase for cancellation or maturity of the convertible debentures being offered by us in the concurrent public offering.

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Summary historical financial information

The following table presents summary consolidated financial information, which should be read in conjunction with our consolidated financial statements beginning on page F-1 and the related notes thereto, and "Management's discussion and analysis of financial condition and results of operations" beginning on page 34. The annual historical information for each of the years in the three-year period ended December 31, 2009 has been derived from our audited consolidated financial statements included elsewhere in this prospectus. The historical information for the six-month periods ended June 30, 2009 and 2010 has been derived from our unaudited consolidated financial statements included elsewhere in this prospectus.

	Year ended December 31,					Six months ended June 30,	
	2009	2008	2007	2006 ^(a)	2005 ^(a)	2010 ^(a)	2009 ^(a)
(in thousands of U.S. dollars, except as otherwise stated)							
Project revenue	\$ 179,517	\$ 173,812	\$ 113,257	\$ 69,374	\$ 57,711	\$ 95,125	\$ 90,304
Project income	48,415	41,006	70,118	57,247	48,256	19,405	25,995
Net (loss) income attributable to Atlantic Power Corporation	(38,486)	48,101	(30,596)	(2,408)	(509)	(4,618)	(6,486)
Basic earnings (loss) per share, US\$	\$ (0.63)	\$ 0.78	\$ (0.50)	\$ (0.05)	\$ (0.01)	\$ (0.08)	\$ (0.11)
Basic earnings (loss) per share, Cdn\$ ^(b)	\$ (0.72)	\$ 0.84	\$ (0.53)	\$ (0.06)	\$ (0.02)	\$ (0.08)	\$ (0.13)
Diluted earnings (loss) per share, US\$ ^(c)	\$ (0.63)	\$ 0.73	\$ (0.50)	\$ (0.05)	\$ (0.01)	\$ (0.08)	\$ (0.11)
Diluted earnings (loss) per share, Cdn\$ ^{(b)(c)}	\$ (0.72)	\$ 0.78	\$ (0.53)	\$ (0.06)	\$ (0.02)	\$ (0.08)	\$ (0.13)
Distribution declared per IPS	\$ 0.51	\$ 0.60	\$ 0.59	\$ 0.57	\$ 0.53	\$	\$ 0.29
Dividend declared per common share	\$ 0.46	\$ 0.40	\$ 0.40	\$ 0.37	\$ 0.31	\$ 0.52	\$ 0.19
Total assets	\$ 869,576	\$ 907,995	\$ 880,751	\$ 965,121	\$ 636,138	\$ 862,525	\$ 873,923
Total long-term liabilities	\$ 402,212	\$ 654,499	\$ 715,923	\$ 613,423	\$ 475,533	\$ 407,413	\$ 675,159

(a) *Unaudited*

(b) *The Cdn\$ amounts were converted using the average exchange rates for the applicable reporting 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, 2009, 2007, 2006 and 2005, and for the six month periods ended June 30, 2010 and 2009, the effect of including potentially dilutive shares in the calculation during those periods is anti-dilutive. Please see the notes to our historical consolidated financial statements included elsewhere in this prospectus for information relating to the number of shares used in calculating basic and diluted earnings per share for the periods presented.*

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Risk factors

Investing in our common shares involves a high degree of risk. In addition to other information contained in this prospectus you should carefully consider the risks described below in evaluating our company and our business before making a decision to invest in our common shares. These risks are not the only ones faced by us. Additional risks not presently known or that we currently deem immaterial could also materially and adversely affect our financial condition, results of operations, business and prospects. The trading price of our common shares could decline due to any of these risks, and you may lose all or part of your investment. This prospectus also contains forward-looking statements that involve risks and uncertainties. Actual results could differ materially from those anticipated in these forward-looking statements as a result of certain factors, including the risks faced by us described below and elsewhere in this prospectus. Please refer to the section entitled "Cautionary statements regarding forward-looking statements" in this prospectus.

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. For example, PPAs at our Rumford, Badger Creek and Topsham projects expire between now and the end of 2011 and represent 52 MWs of our net generating capacity and the PPAs at our Auburndale, Lake and Gregory projects expire by the end of 2013 and represent 335 MWs of our net generating capacity. The table on page 5 contains details about all our projects' PPAs. In addition, these PPAs may be subject to termination 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 equity method of accounting, are Progress Energy Florida, Inc. ("PEF"), Tampa Electric Company ("TECO"), and Atlantic City Electric ("ACE"), which purchase approximately 40%, 15% and 11%, respectively, of the net electric generation capacity of our projects. The amount of cash available to pay dividends to shareholders 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 with no PPA or PPAs based on spot market pricing 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.

Our most significant exposure to market power prices is at the Selkirk and Chambers projects. At Selkirk, approximately 23% of the capacity of the facility is not contracted and is sold at market

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prices or not sold at all if market prices do not support profitable operation of that portion of the facility. 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.

Our projects may not operate as planned

The revenue generated by our power generation projects is dependent, in whole or in part, on the amount of electric energy and steam generated by them. The ability of our projects to generate the required amount of power to be sold to customers under the PPAs is a primary determinant 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, 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 forecast down times for maintenance and repair, or suffers disruptions of 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 spare transformer can be found or a replacement 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, a project-level debt agreement or otherwise mitigate impacts through business interruption insurance policies. If successful, such a claim 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.

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

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 payments 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.

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. Our project operators 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. 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

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do not effectively pass through changes in natural gas prices. We have executed a hedging program to substantially mitigate this risk through 2013.

The amount of energy generated at the projects is dependent upon the availability of natural gas, coal, oil or biomass. The long-term availability of such resources may not remain unchanged.

Our projects depend on a favorable regulatory regime

The profitability of our projects is in part dependent upon the continuation of a favorable regulatory climate with respect to the continuing operations and the future growth and development of the independent power industry. Should the regulatory regime in an applicable jurisdiction be modified in a manner which adversely affects the projects, including increases in taxes and permit fees, dividends to shareholders may be adversely affected. The failure to obtain all necessary licenses or permits, including renewals thereof or modifications thereto, may also adversely affect cash available to pay dividends.

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 Federal Energy Regulatory Commission, or "FERC," regarding the terms and conditions of wholesale service and rates, as well as by state agencies regarding PPAs entered into by qualifying facility projects and the siting of the generation facilities. The majority of our generation is sold by qualifying facility 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 to certain markets that lack 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 qualifying facility were to lose its status as a qualifying facility, 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 qualifying facility status could trigger defaults under covenants to maintain qualifying facility status in the PPAs, steam sales agreements 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, plus interest.

Our projects would also have to file with the FERC for market-based rates or file for acceptance for filing of the rates set forth in the applicable PPA, and our projects' rates would then be subject to initial and potentially subsequent reviews by the FERC under the Federal Power Act, which could result in reductions to the rates.

Our projects require licenses, permits and approvals which can be in addition to any required environmental permits. No assurance can be provided that we will be able to obtain, comply with and renew, as required, all necessary licenses, permits and approvals for these facilities. If we cannot comply with and renew as required all applicable licenses, permits and approvals, our business, results of operations and financial condition could be adversely affected.

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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 which imposes 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.

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 upon its rate review every three years, and a rate review is set to commence in 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 in 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 the North American Electric Reliability Corporation ("NERC"), a self-regulatory organization that is a non-governmental entity which has statutory responsibility to regulate bulk power system users, 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. NERC and the FERC have assigned a Violation Risk Factor of High, Medium, or Lower to each requirement of the mandatory reliability standards corresponding to the risk to the bulk power system associated with a violation of that requirement. 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.

Our projects are subject to significant environmental and other regulations

Our projects are subject to numerous and significant federal, state 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. As such, the operation of our projects carries an inherent risk of environmental, health and safety liabilities (including potential

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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.

The Clean Air Act and related regulations and programs of the Environmental Protection Agency extensively regulate the air emissions of sulfur dioxide, nitrogen oxides, mercury and other compounds emitted by power plants. Environmental laws and regulations have generally become more stringent over time, and this trend may continue. In particular, the U.S. Environmental Protection Agency has promulgated regulations under the federal Clean Air Interstate Rule ("CAIR") requiring additional reductions in nitrogen oxides, or "NO_x," and sulphur dioxide, or "SO₂," emissions, beginning in 2009 and 2010 respectively, and has also promulgated regulations requiring reductions in mercury emissions from coal-fired electric generating units, beginning in 2010 with more substantial reductions in 2018. Moreover, certain of the states in which we operate have promulgated air pollution control regulations which are more stringent than existing and proposed federal regulations.

While CAIR was set aside by a court decision in 2008, that decision allowed the CAIR requirements to remain in place pending further rulemaking by the Environmental Protection Agency. On July 6, 2010, the Environmental Protection Agency proposed to replace CAIR by requiring 31 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 budgets for nitrogen oxides and sulfur dioxide. Compliance with the proposed rule, which would take effect in 2012, may have a material adverse impact on our business, operations or financial condition.

The Environmental Protection Agency intends to propose new mercury emissions standards for power plants by March 2011 and to have new standards in place by November 2011. Meeting these new standards at our coal-fired facilities 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 coal-fired facilities may be subject to increased compliance obligations and costs that may have a material adverse impact on our business, operations or financial condition.

Significant expenditures may be required 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. If it is not economical to make those expenditures it may be necessary to retire or mothball facilities, or restrict or modify our operations to comply with more stringent standards.

Our projects have obtained environmental permits and other approvals that are required for their operations. Compliance with applicable environmental laws, regulations, permits and approvals and material future changes to them could materially impact our businesses. Although we believe the operations of the projects are currently in material compliance with applicable environmental laws, licenses, permits and other authorizations required for the operation of the projects and although there are environmental monitoring and reporting systems in place with respect to all the projects, there is no guarantee that more stringent laws will not be imposed, that there will not be more stringent

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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.

Our projects are subject to regulation of CO₂ and other greenhouse gases

Ongoing public concerns about emissions of CO₂ and other greenhouse gases from power plants 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 CO₂ 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. CO₂ allocations are now a tradeable commodity, currently averaging in the \$2.05 to \$3.20/ton range. The State of Florida has conducted stakeholder meetings as part of the process of developing greenhouse gas emissions regulations, the most recent of which was in January 2009. Discussions indicate favoring a program similar to that of the Regional Greenhouse Gas Initiative.

California, New Mexico, Washington and other states 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, more commonly known as AB 32 and SB 1368, are currently in the regulatory rulemaking phase which will involve public comment and negotiations over specific provisions. Development towards the implementation of these programs continues.

Under AB 32 (the California Global Warming Act of 2006) the California Air Resources Board 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. This will most likely require that electric generating facilities reduce their emissions of greenhouse gases or pay for the right to emit by the implementation date of January 1, 2012. The program has yet to be finalized and the decision as to whether allocations will be distributed or auctioned will be determined in the rulemaking process that is currently underway. Discussion to date favors an auction-based allocation program.

SB 1368 added the requirement that the California Energy Commission, in consultation with the California Public Utilities Commission (the "CPUC") and the California Air Resources Board establish greenhouse gas emission performance standards and implement regulations for power purchase agreements that exceed five 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 Badger Creek project. Provisions are under consideration in the rulemaking to allow facilities that have higher CO₂ emissions to be able to negotiate PPA's for up to a five-year period or sell power to entities not subject to SB 1368.

In addition to the regional initiatives, legislation for the regulation 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. Federal bills to create both a cap-and-trade allowance system and a renewable/efficiency portfolio standard have been introduced in both the house and senate. Separately, the U.S. Environmental Protection Agency has taken several recent actions to regulate greenhouse gas emissions.

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The Environmental Protection Agency's recent 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 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, to take effect in 2011, which requires large industrial facilities, including power plants, to obtain permits to emit, and to use best available control technology to curb emissions of, greenhouse gases.

In addition, the United States is actively participating in various international initiatives to reduce greenhouse gas emissions globally that may result in further regulatory developments in the United States.

The implementation of existing CO₂ and other greenhouse gas regulations, 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.

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 un-contracted 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. In addition, many states have implemented or are considering regulatory initiatives designed to increase competition in the U.S. power industry. 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 many 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 and GE) 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 that acquisitions will be successfully integrated into our existing operations.

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

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

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.

Financing arrangements could negatively impact our business

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. As of September 14, 2010, we had \$20.0 million outstanding under our revolving credit facility, \$142.3 million of outstanding convertible debentures, and \$232.9 million of outstanding non-recourse project-level debt. Covenants in these borrowings may also adversely affect cash available for dividends. In addition, most of the projects currently have term loan 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 the equity interests in the project operator (including those owned by us). The terms of these financing arrangements generally impose many covenants and obligations on the part of the project operator and other borrowers and guarantors. For example, some agreements contain requirements to maintain specified debt service coverage ratios before cash may be distributed from the relevant project to us. In many cases, a default by any party under other 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 project to us and may entitle the lenders to demand repayment and/or enforce their security interests.

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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 and we may be required to sell assets or take other actions, including the initiation of bankruptcy proceedings or the commencement of an out-of-court debt restructuring.

Our equity interests in our 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 the 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.

RISKS RELATED TO OUR STRUCTURE

We are dependent on our projects for virtually all cash available for dividends

We are dependent on the operations and assets of the projects through our indirect ownership of interests in the projects. The actual amount of cash available for dividends to our shareholders depends upon numerous factors, including profitability, changes in revenues, fluctuations in working capital, availability under existing credit facilities, capital expenditure levels, applicable laws, compliance with contracts and contractual restrictive covenants contained in any debt documentation.

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Distribution of available cash may restrict our potential growth

A payout of a significant portion of substantially all of our operating cash flow will 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 because they may not be accretive to us on a short-term basis.

Future dividends are not guaranteed

Our board of directors may, in their discretion, amend or repeal our existing dividend policy. 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 our amount of cash available for dividends

Our payments to shareholders and convertible debenture holders are denominated in Canadian dollars. Conversely, all 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 2013, 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 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 to our shareholders, including:

- > our ability in the future to obtain additional financing for working capital, capital expenditures, acquisitions or other purposes may be limited;
- > we may be unable to refinance indebtedness on terms acceptable to us or at all; and
- > we may be limited in our ability to react to competitive pressures.

As of June 30, 2010, our consolidated long-term debt and our share of the debt of our unconsolidated affiliates represented approximately 55% of our total capitalization, comprised of debt and balance sheet equity.

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.

Future issuances of our common shares could result in dilution

Our articles of incorporation authorize the issuance of an unlimited number of common shares for such consideration and on such terms and conditions as are established by our board of directors without the approval of any of our shareholders. We may issue additional common shares in connection with a future financing or acquisition. The issuance of additional common shares may dilute an investor's investment in us and reduce cash available for distribution per common share.

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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. We expect that our existing tax attributes initially will be available to offset this income inclusion such that it 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 ("CRA") administrative policies respecting the Canadian federal income tax consequences generally applicable to us, to our subsidiaries, or to a holder of common shares will not be changed in a manner which adversely affects holders of our common shares.

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

Under our prior IPS structure, we treated the subordinated notes as debt for U.S. federal income tax purposes. Accordingly, we deducted the interest payments on the subordinated notes and reduced our net taxable income treated as "effectively connected income" for U.S. federal income tax purposes. Under our current structure, our subsidiaries that are incorporated in the United States are subject to U.S. federal income tax on their income at regular corporate rates (currently as high as 35%, plus state and local taxes), and our U.S. holding company will claim interest deductions with respect to the Intercompany Note in computing its income for U.S. federal income tax purposes. To the extent this interest expense is disallowed or is otherwise not deductible, the U.S. federal income tax liability of our U.S. holding company 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 company 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, it is possible that the Internal Revenue Service ("IRS") could

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successfully challenge those positions and assert that subordinated notes or the Intercompany Note should be treated as equity rather than debt for U.S. federal income tax purposes. In this case, the otherwise deductible interest on the subordinated notes or the Intercompany Note would be treated as non-deductible distributions and, in the case of the Intercompany Note, would 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 whether the subordinated notes and the U.S. holding company's indebtedness to us is debt or equity 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 expenses on either the subordinated notes or the Intercompany Note 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 or the Intercompany Note 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 case of the Intercompany Note, the remainder would be subject to U.S. withholding tax to the extent our U.S. holding company had current or accumulated earnings and profits. We have received advice from independent advisors that the interest rate on the subordinated notes and the Intercompany Note was and is, as applicable, commercially reasonable in the circumstances, but the advice is not binding on the IRS.

Furthermore, our U.S. holding company's deductions attributable to the interest expense on the Intercompany Note 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, less its interest income) exceeds 50% of its adjusted taxable income (generally, U.S. federal taxable income before net interest expense, net operating loss carryovers, depreciation and amortization). Any disallowed interest expense may currently be carried forward to future years. 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 company does not make regular interest payments as required under the Intercompany Note, 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 with respect to the Intercompany Note.

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.

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RISKS RELATED TO THE COMMON SHARES

Market conditions and other factors may affect the value of our common shares

The trading price of our common shares will depend on many factors, which may change from time to time, including:

- > conditions in the power generation markets and the energy markets generally;
- > interest rates;
- > the market for similar securities;
- > government action or regulation;
- > general economic conditions or conditions in the financial markets;
- > our past and future dividend practice; and
- > our financial condition, performance, creditworthiness and prospects.

Accordingly, the common shares that an investor purchases, whether in this offering or in the secondary market, may trade at a price lower than that at which they were purchased.

The market price and trading volume of our common shares may be volatile

The market price of our common shares may be volatile, particularly given the current economic environment. In addition, the trading volume in our common shares may fluctuate and cause significant price variations to occur. If the market price of our common shares declines significantly, you may be unable to resell your shares at or above the public offering price. The market price of our common shares may fluctuate or decline significantly in the future.

Some of the factors that could negatively affect our share price or result in fluctuations in the price or trading volume of our common shares include:

- > quarterly variations in our operating results or the quality of our assets;
- > changes in applicable regulations or government action;
- > operating results that vary from the expectations of management, securities analysts and investors;
- > changes in expectations as to our future financial performance;
- > announcements of innovations, new products, strategic developments, significant contracts, acquisitions and other material events by us or our competitors;

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- > changes in financial estimates or publication of research reports and recommendations by financial analysts or actions taken by rating agencies with respect to us or other companies in our industry;
- > the operating and securities price performance of other companies that investors believe are comparable to us;
- > changes in general market conditions, such as interest or foreign exchange rates, stock or commodity valuations, or volatility; and
- > actions by our current shareholders, including sales of our common shares by existing shareholders and/or directors and executive officers.

Stock markets in general have experienced significant volatility over the past two years, and continue to experience significant price and volume volatility. As a result, the market price of our common shares may continue to be subject to similar market fluctuations that may be unrelated to our

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Risk factors

operating performance or prospects. Increased volatility could result in a decline in the market price of our common shares.

Present and future offerings of debt or equity securities, ranking senior to our common shares, may adversely affect the market price of our common shares

If we decide to issue debt or equity securities ranking senior to our common shares in the future it is likely that they will be governed by an indenture or other instrument containing covenants restricting our operating flexibility. Additionally, any convertible or exchangeable securities that we issue in the future may have rights, preferences and privileges more favorable than those of holders of our common shares and may result in dilution to holders of our common shares. We and, indirectly, our shareholders, will bear the cost of issuing and servicing such securities. Because our decision to issue debt or equity securities in any future offering will depend on market conditions and other factors beyond our control, we cannot predict or estimate the amount, timing or nature of our future offerings. Thus, holders of our common shares will bear the risk of our future offerings reducing the market price of our common shares and diluting the value of their share holdings in us.

The number of shares available for future sale could adversely affect the market price of our common shares

We cannot predict whether future issuances of our common shares or the availability of shares for resale in the open market will decrease the market price per common share. We may issue additional common shares, including securities that are convertible into or exchangeable for, or that represent the right to receive common shares. Sales of a substantial number of common shares in the public market or the perception that such sales might occur could materially adversely affect the market price of our common shares. Because our decision to issue securities in any future offering will depend on market conditions and other factors beyond our control, we cannot predict or estimate the amount, timing or nature of our future offerings. Thus, our shareholders bear the risk of our future offerings reducing the market price of our common shares and diluting their share holdings in us.

The exercise of the underwriters' option to purchase additional common shares, the exercise of any options granted to directors, executive officers and other employees under our stock compensation plans, and other issuances of our common shares could have an adverse effect on the market price of our common shares, and the existence of options may materially adversely affect the terms upon which we may be able to obtain additional capital through the sale of equity securities. In addition, future sales of our common shares may be dilutive to existing shareholders.

The redemption of our outstanding debentures for or repayment of principal by issuing common shares may cause common shareholders dilution

We may determine to redeem outstanding debentures for common shares or to repay outstanding principal amounts thereunder at maturity of the debentures by issuing additional common shares. The issuance of additional common shares may have a dilutive effect on shareholders and an adverse impact on the price of our common shares.

Provisions of our articles of continuance could discourage potential acquisition proposals and could deter or prevent a change in control

We are governed by the Business Corporations Act (British Columbia). Our articles of continuance contain provisions that could have the effect of delaying, deferring or discouraging another party from acquiring control of our company by means of a tender offer, a proxy contest or otherwise. These provisions may make it more difficult for other persons, without the approval of our board of directors, to make a tender offer or otherwise acquire a substantial number of our common shares or to launch other takeover attempts that a shareholder might consider to be in his or her best interest. These provisions could limit the price that some investors might be willing to pay in the future for our common shares.

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Cautionary statements regarding forward-looking statements

Certain statements contained in this prospectus and in any related prospectus that are not historical facts may constitute forward-looking statements. Forward-looking statements involve risks and uncertainties. These statements, which are based on certain assumptions and describe our future plans, projections, strategies and expectations, can generally be identified by the use of the words "outlook," "objective," "may," "will," "should," "could," "would," "plan," "potential," "estimate," "project," "continue," "believe," "intend," "anticipate," "expect," "target" or the negatives of these words and phrases or similar expressions that are predictions of or indicate future events or trends and which do not relate solely to present or historical matters. These forward-looking statements include, but are not limited to, statements relating to:

- > our objectives, business, asset management and acquisition strategies;
- > success of acquisitions, future operations, market position and financial position;
- > expected opportunities for accretive acquisitions;
- > the amount of distributions expected to be received from the projects for the full year 2010;
- > estimated net cash tax refund in 2010;
- > our forecast of expected after-tax cash flows from Idaho Wind for each full year of operations;
- > our forecast of expected annual cash distributions from the Lake and Auburndale projects through 2012;
- > our forecast of expected closing of construction financing for our Piedmont project;
- > the expected resumption of distributions from our Chambers, Selkirk and Delta projects in 2011; and
- > the expected use of proceeds from this offering and the concurrent offering of convertible debentures.

Such forward-looking statements reflect our current expectations regarding future events and operating performance and speak only as of the date of this prospectus. Such forward-looking statements are based on a number of assumptions which may prove to be incorrect, including, but not limited to the assumption that the projects will operate and perform in accordance with our expectations. Forward-looking statements involve significant risks and uncertainties, should not be read as guarantees of future performance or results, and will not necessarily be accurate indications of whether or not or the times at or by which such performance or results will be achieved. A number of factors could cause actual results to differ materially from the results discussed in the forward-looking statements, including, but not limited to, the factors discussed under "Risk factors" in this prospectus. Our business is both competitive and subject to various risks.

These risks include, without limitation:

- > a reduction in revenue upon expiration or termination of power purchase agreements;
- > the dependence of our projects on their electricity, thermal energy and transmission services customers;
- >

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

>

projects not operating to plan;

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Cautionary statements regarding forward-looking statements

- > the impact of significant environmental and other regulations on our projects;
- > increased competition, including for acquisitions;
- > our limited control over the operation of certain minority-owned projects; and
- > changes in assumptions used in making such forward-looking statements.

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

Material factors or assumptions that were applied in drawing a conclusion or making an estimate set out in the forward-looking information include third party projections of regional fuel and electric capacity and energy prices or cash flows that are based on assumptions about future economic conditions and courses of action. Although the forward-looking statements contained in this prospectus are based upon what are believed to be reasonable assumptions, investors cannot be assured that actual results will be consistent with these forward-looking statements, and the differences may be material. Therefore, investors are urged not to place undue reliance on our forward-looking statements. Certain statements included in this prospectus may be considered "financial outlook" for the purposes of applicable securities laws, and such financial outlook may not be appropriate for purposes other than this prospectus.

These forward-looking statements are made as of the date of this prospectus and, except as expressly required by applicable law, we assume no obligation to update or revise them to reflect new events or circumstances.

Exchange rate information

The following table sets forth, for each period indicated, the high and low exchange rates for one U.S. dollar, expressed in Canadian dollars, the average of such exchange rates on the last day of each month during such period and the exchange rate at the end of such period, based on the noon buying rate as quoted by the Bank of Canada. On September 14, 2010, the noon buying rate was US\$1.00 = Cdn\$1.0222.

	Six months ended June 30,		12 months ended December 31,	
	2010	2009	2009	2008
High	Cdn\$1.0778	Cdn\$1.3000	Cdn\$1.3000	Cdn\$1.2969
Low	Cdn\$0.9961	Cdn\$1.0827	Cdn\$1.0292	Cdn\$0.9719
Average	Cdn\$1.0338	Cdn\$1.2062	Cdn\$1.1420	Cdn\$1.0660
Period end	Cdn\$1.0606	Cdn\$1.1625	Cdn\$1.0466	Cdn\$1.2112

Source: Bank of Canada

Use of proceeds

We expect to receive net proceeds from this offering of approximately \$55.9 million after deducting the underwriting discounts and our estimated expenses of this offering (or approximately \$64.4 million if the underwriters exercise their option to purchase additional common shares in full). We intend to use the net proceeds from this offering and the concurrent offering of convertible debentures as follows:

- (i) approximately \$20 million to repay indebtedness incurred under our credit facility in June, 2010 to partially fund our previously-announced acquisition of a 27.6% equity interest in Idaho Wind Partners 1, LLC; and
- (ii) up to \$75 million to fund an investment in the Piedmont Green Power biomass project in Barnesville, Georgia for substantially all of the equity interest in the project.

Any remaining net proceeds will be used to fund additional growth opportunities and for general corporate purposes.

This offering is not conditioned upon the successful completion of the concurrent offering of convertible debentures and the concurrent offering of convertible debentures is not conditioned upon the successful completion of this offering. We expect to receive net proceeds from the concurrent offering of convertible debentures of approximately Cdn\$47.1 million after deducting the underwriting discounts and our estimated expenses of the concurrent offering of convertible debentures (or approximately Cdn\$54.3 million if the underwriters exercise in full their option to purchase additional debentures).

If the concurrent offering of convertible debentures is not successfully completed, we intend to use the net proceeds from this offering to partially fund the anticipated \$75 million investment in the Piedmont Green Power biomass project and borrow from our revolving credit facility to fund any deficiency.

As of September 14, 2010, borrowings under our revolving credit facility were \$20 million and were used to fund acquisitions. The revolving credit facility has a maturity date of August 12, 2012. Borrowings under the credit facility accrue interest at the London Interbank Offered Rate ("LIBOR") plus an applicable margin between 1.50% and 3.25% that varies based on the credit statistics of one of our subsidiaries. The margin is currently 1.50%.

Dividend policy

On November 24, 2009, our shareholders approved our conversion to a common share structure. Subsequent to the conversion, we have continued to maintain our business strategy and our current distribution levels. Each IPS has been exchanged for one new common share. Our entire current monthly cash distribution of Cdn\$0.0912 per common share is being paid as a dividend on the new common shares on the last business day of each month for holders of record on the last business day of the immediately preceding month. We expect to continue paying cash dividends in the future in amounts that are comparable to the distributions paid in 2009. Future dividends are paid at the discretion of our board of directors subject to our earnings and cash flow and are not guaranteed. The primary risk that impacts our ability to continue paying cash dividends at the current rate is the operating performance of our projects and their ability to distribute cash to us after satisfying project-level obligations.

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Market price of and dividends on the common shares and related shareholder matters

The IPSs were listed and posted for trading on the TSX under the symbol ATP.UN from our initial public offering in November 2004 through November 30, 2009. Following the closing of the exchange of IPSs for common shares, our new common shares commenced trading on the TSX on December 2, 2009 under the symbol ATP. The following table sets forth the price ranges of the outstanding IPSs and common shares, as applicable, as reported by the TSX for the periods indicated.

Period	High (Cdn\$)	Low (Cdn\$)
Quarter ended September 30, 2010 (through September 14, 2010)	13.74	12.11
Quarter ended June 30, 2010	12.90	11.20
Quarter ended March 31, 2010	13.85	11.50
Quarter ended December 31, 2009	11.90	9.08
Quarter ended September 30, 2009	9.49	8.55
Quarter ended June 30, 2009	9.45	7.71
Quarter ended March 31, 2009	9.28	6.34
Quarter ended December 31, 2008	8.53	4.90
Quarter ended September 30, 2008	9.30	6.28
Quarter ended June 30, 2008	10.38	7.37
Quarter ended March 31, 2008	11.00	9.67

Table of Contents**Market price of and dividends on the common shares and related shareholder matters**

The following table shows the dividends declared for the periods indicated in Canadian dollars.

Period	Dividends declared* (Cdn\$)
For the month ended September 30, 2010	0.091**
For the month ended August 31, 2010	0.091
For the month ended July 31, 2010	0.091
For the month ended June 30, 2010	0.091
For the month ended May 31, 2010	0.091
For the month ended April 30, 2010	0.091
For the month ended March 31, 2010	0.091
For the month ended February 28, 2010	0.091
For the month ended January 31, 2010	0.091
For the month ended December 31, 2009	0.091
For the month ended November 30, 2009	0.091
For the month ended October 31, 2009	0.091
For the month ended September 30, 2009	0.091
For the month ended August 31, 2009	0.091
For the month ended July 31, 2009	0.091
For the month ended June 30, 2009	0.091
For the month ended May 31, 2009	0.091
For the month ended April 30, 2009	0.091
For the month ended March 31, 2009	0.091
For the month ended February 28, 2009	0.091
For the month ended January 31, 2009	0.091
For the month ended December 31, 2008	0.091
For the month ended November 30, 2008	0.088
For the month ended October 31, 2008	0.088
For the month ended September 30, 2008	0.088
For the month ended August 31, 2008	0.088
For the month ended July 31, 2008	0.088
For the month ended June 30, 2008	0.088
For the month ended May 31, 2008	0.088
For the month ended April 30, 2008	0.088
For the month ended March 31, 2008	0.088
For the month ended February 29, 2008	0.088
For the month ended January 31, 2008	0.088

*

Dividends include amounts distributed to holders of our IPSs in respect of both interest on the subordinated notes and dividends on the common shares.

**

We declared a dividend of Cdn\$0.091 per common share on September 15, 2010 to be paid on October 29, 2010 to holders of record at the close of business on September 30, 2010.

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Market price of and dividends on the common shares and related shareholder matters

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 September 14, 2010.

Period	High (US\$)	Low (US\$)
July 23, 2010 through September 14, 2010	13.48	12.10

The following table shows the dividends declared for the periods indicated in U.S. dollars.

Period	Dividends declared (US\$)
For the month ended August 31, 2010	0.087
For the month ended September 30, 2010	0.089*

*

We declared a dividend of \$0.089 per common share on September 15, 2010 to be paid on October 29, 2010 to holders of record at the close of business on September 30, 2010.

On September 14, 2010, the closing price for our common shares on the TSX was Cdn\$13.64, and the closing price for our common shares on the NYSE was \$13.27. See "Exchange rate information" on page 26 for information regarding the exchange rate between Canadian dollars and U.S. dollars. There were approximately 36,600 shareholders of record of our common shares as of September 14, 2010.

Securities authorized for issuance under equity compensation plans

See "Management compensation discussion and analysis" for information related to securities authorized for issuance under our equity compensation plans.

Capitalization

The following table shows our capitalization as of June 30, 2010 on a historical basis and on an as adjusted basis to give effect to:

- > the sale of our common shares, at an assumed offering price of \$13.27 per share, the last reported sale price of our common shares on the New York Stock Exchange on September 14, 2010, after deducting underwriting discounts and estimated transaction expenses payable by us;
- > the concurrent offering and sale of Cdn\$50,000,000 of our % Series B convertible unsecured subordinated debentures due , after deducting underwriting discounts and estimated transaction expenses payable by us; and
- > the repayment of \$20 million borrowed under our revolving credit facility in June 2010 from the net proceeds of this offering.

You should read the information set forth in the table below together with our unaudited consolidated interim financial statements and the related notes for the six months ended June 30, 2010 included in this prospectus.

	As of June 30, 2010	
	Historical	As adjusted
	(unaudited)	
	(in thousands)	
Cash and cash equivalents:	\$ 63,314	\$ 145,231
Debt:		
Revolving credit facility ⁽¹⁾	\$ 20,000	\$
Convertible debentures due 2014	56,360	56,360
Convertible debentures due 2017	81,016	81,016
Convertible debentures due		48,914
Current portion of project-level debt	18,330	18,330
Project-level debt	214,527	214,527
Total debt:	390,233	419,147
Shareholder's equity:		
Common shares, no par value per share, unlimited authorized shares, 60,510 shares issued and outstanding, actual; 65,010 shares issued and outstanding, as adjusted ⁽²⁾	544,647	600,516
Accumulated other comprehensive loss	(194)	(194)
Retained deficit	(163,299)	(163,299)
Non-controlling interest	3,481	3,481
Total shareholder's equity	384,635	440,504
Total capitalization	\$ 774,868	\$ 859,651

(1)

As of September 14, 2010, the outstanding borrowings on our revolving credit facility were \$20 million. On July 2, 2010, we acquired a 27.6% equity interest in Idaho Wind Partners 1, LLC for approximately \$40 million, which purchase price we financed in part by borrowing under our revolving credit facility.

(2)

Excludes (i) 11,471,055 shares issuable upon conversion, redemption, purchase for cancellation or maturity of our outstanding convertible debentures, (ii) any shares upon conversion, redemption, purchase for cancellation or maturity of the convertible debentures being offered by us in the concurrent public offering, and (iii) 582,000 unvested notional units granted under the terms of our Long Term Incentive Plan.

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Selected historical financial information

The following table presents selected consolidated financial information, which should be read in conjunction with our consolidated financial statements beginning on page F-1 and the related notes thereto, and "Management's discussion and analysis of financial condition and results of operations" beginning on page 34. The annual historical information for each of the years in the three-year period ended December 31, 2009 has been derived from our audited consolidated financial statements included elsewhere in this prospectus. The historical information for the six-month periods ended June 30, 2009 and 2010 has been derived from our unaudited consolidated financial statements included elsewhere in this prospectus.

	Year ended December 31,					Six months ended June 30,	
	2009	2008	2007	2006 ^(a)	2005 ^(a)	2010 ^(a)	2009 ^(a)
(in thousands of U.S. dollars, except as otherwise stated)							
Project revenue	\$ 179,517	\$ 173,812	\$ 113,257	\$ 69,374	\$ 57,711	\$ 95,125	\$ 90,304
Project income	48,415	41,006	70,118	57,247	48,256	19,405	25,995
Net (loss) income attributable to Atlantic Power Corporation	(38,486)	48,101	(30,596)	(2,408)	(509)	(4,618)	(6,486)
Basic earnings (loss) per share, US\$	\$ (0.63)	\$ 0.78	\$ (0.50)	\$ (0.05)	\$ (0.01)	\$ (0.08)	\$ (0.11)
Basic earnings (loss) per share, Cdn\$ ^(b)	\$ (0.72)	\$ 0.84	\$ (0.53)	\$ (0.06)	\$ (0.02)	\$ (0.08)	\$ (0.13)
Diluted earnings (loss) per share, US\$ ^(c)	\$ (0.63)	\$ 0.73	\$ (0.50)	\$ (0.05)	\$ (0.01)	\$ (0.08)	\$ (0.11)
Diluted earnings (loss) per share, Cdn\$ ^{(b)(c)}	\$ (0.72)	\$ 0.78	\$ (0.53)	\$ (0.06)	\$ (0.02)	\$ (0.08)	\$ (0.13)
Distribution declared per IPS	\$ 0.51	\$ 0.60	\$ 0.59	\$ 0.57	\$ 0.53		\$ 0.29
Dividend declared per common share	\$ 0.46	\$ 0.40	\$ 0.40	\$ 0.37	\$ 0.31	\$ 0.52	\$ 0.19
Total assets	\$ 869,576	\$ 907,995	\$ 880,751	\$ 965,121	\$ 636,138	\$ 862,525	\$ 873,923
Total long-term liabilities	\$ 402,212	\$ 654,499	\$ 715,923	\$ 613,423	\$ 475,533	\$ 407,413	\$ 675,159

(a) *Unaudited*

(b) *The Cdn\$ amounts were converted using the average exchange rates for the applicable reporting 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, 2009, 2007, 2006 and 2005, and for the six month periods ended June 30, 2010 and 2009, the effect of including potentially dilutive shares in the calculation during those periods is anti-dilutive. Please see the notes to our historical consolidated financial statements included elsewhere in this prospectus for information relating to the number of shares used in calculating basic and diluted earnings per share for the periods presented.*

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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 consolidated financial statements and notes thereto. All dollar amounts discussed below are in 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").

This report contains, in addition to historical information, forward-looking statements that involve risks and uncertainties. These forward-looking statements reflect our current views about future events and financial performance. Forward-looking statements are subject to a variety of factors that could cause actual results to differ materially from our expectations. Factors that could cause, or contribute to such differences include, without limitation, the factors described under "Risk factors." In view of these uncertainties, investors are cautioned not to place undue reliance on these forward-looking statements. We assume no obligation, unless required by law, to update or revise publicly any forward-looking statements, whether as a result of new information, future events or otherwise.

OVERVIEW

Atlantic Power Corporation is an independent power producer, with power projects located in major markets in the United States. Our current portfolio consists of interests in 12 operational power generation projects across eight states, one wind project under construction in Idaho, a 500 kilovolt 84-mile electric transmission line located in California, and six development projects in five states. Our power generation projects in operation have an aggregate gross electric generation capacity of approximately 1,823 megawatts (or "MW"), in which our ownership interest is approximately 808 MW.

We sell the capacity and power from our power generation projects under power purchase agreements (or "PPAs") with a variety of utilities and other parties. Under the PPAs, which have expiration dates ranging from 2010 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 most of the PPAs and steam sales agreements provide for the pass-through or indexing of fuel costs to our customers.

We partner with recognized leaders in the independent power business to operate and maintain our projects, including Caithness, Power Plant Management Services and Western. Under these operation, maintenance and management agreements, the operator is typically responsible for operations, maintenance and repair services.

CURRENT TRENDS IN OUR BUSINESS

Recession-related impacts

The recession caused significant decreases in both peak electricity demand and consumption that varied by region, although as always, upcoming summer peak demand will also be greatly influenced by weather. This has the effect of delaying projected increases in capacity requirements in varying degrees

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Management's discussion and analysis of financial condition and results of operations

by region. Historically, electricity demand has made a strong recovery to pre-recession levels along with the economic recovery and the postponement of generation capacity additions are reduced 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 to meet the historical pattern of demand during the "peak" portion of most days, but not at night or in other lower demand periods such as weekends). During recessionary periods, base load plants are 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 incipient 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 provisions, state Renewable Portfolio Standards and state or regional CO₂/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 idled 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 and siting cycle.

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 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 have a stifling 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 sense of reduced future volatility of gas prices due to increased supply has reinforced a growing expectation of natural gas' role as a "bridging fuel," helping from a carbon policy perspective to bridge the desired U.S. transition to both cleaner fuels and more commercially viable carbon removal and sequestration technologies.

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Credit markets

Weak credit markets over the past two 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 can be feasibly financed and built. Credit market conditions for project-lending have generally improved in late 2009 and in 2010, but are still much 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 project lenders. Corporate level credit markets have experienced similar adverse impacts, which have impeded the ability of 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 who we believe are primarily focused on income and secondarily on capital appreciation. Because we believe that our shareholders are focused on cash flow measures of our results, we provide supplementary non-GAAP information in this MD&A 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" on page 47 of this prospectus for additional details.

The primary components of our financial results are (i) the operating performance of our projects, (ii) non-cash 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.

Operating performance of our projects

The operating performance of our projects supports cash distributions that are made to us after all operating and capital expenditures and debt service requirements are satisfied at the project-level. Our projects are able to pay distributions to us 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 60% of our power generation revenue in 2009 was related to contractual capacity payments, commodity prices do influence our revenues and 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 our utility 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 our Auburndale and Lake projects is purchased at spot market prices. We have executed a hedging strategy to substantially mitigate this risk. See "Outlook" below for additional details about our hedging program at Auburndale and Lake. Our most significant exposure to market power prices exists at the Selkirk and Chambers projects. At Selkirk, approximately 23% of the capacity of the facility is 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. 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.

- > 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 at our Lake and Auburndale projects expire in 2013. We expect these projects to continue operating and making distributions to us after their existing

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power contracts expire, but with new agreements providing significantly lower levels than the distributions we are currently receiving. The level of these distributions is subject to market conditions at such time as we execute new power agreements for these projects and cannot be estimated at this time. Both of these projects will be free of debt at the time their PPAs expire in 2013, which provides us with some flexibility to pursue the most economic type of contract without restrictions that are sometimes imposed by project-level debt.

>

Some of our projects have non-recourse project-level debt that must be serviced before any distributions can be made to us. The project-level debt agreements typically contain cash flow coverage ratio tests that can prevent distributions to us if project cash flows do not exceed project-level debt service requirements by a specified amount. We are currently not receiving distributions from the Chambers, Selkirk and Delta-Person projects because of such restrictions. We expect to resume receiving distributions from all three of these projects in 2011. See the "Project-level debt" section of "Liquidity and capital resources" on page 60 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 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 "Quantitative and qualitative disclosures about market risk" on page 66 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. In addition, in connection with our common share conversion transaction, we recorded \$16.2 million of charges to interest expense associated with the costs of the conversion and the write-off of unamortized debt issuance costs associated with the subordinated notes that were retired. The conversion transaction resulted in Cdn\$348 million of subordinated notes bearing interest at 11% being converted to equity and, as a result, we expect a significant decrease in our interest expense beginning in 2010.

Our outstanding convertible debentures are denominated in Canadian dollars and, prior to our common share conversion transaction, the outstanding subordinated notes were also 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 statement 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.

OUTLOOK

The discussion below expresses management's outlook and expectations with respect to the future performance of our projects and businesses. Please see "Cautionary statements regarding forward-looking statements."

Based on year-to-date results and our projections for the remainder of the year, we expect to receive distributions from our projects in the range of \$75 million to \$80 million for the full year 2010, an increase from our previous guidance of \$70 million to \$77 million. This amount represents a decrease of approximately \$20 million to \$25 million compared to distributions received from the projects

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in 2009. Changes in project distributions have historically been included in our long-term cash flow projections when we periodically confirm our ability to continue paying dividends to shareholders at current levels. Additional details about these changes are included below.

At the corporate level, we expect a net cash tax refund in 2010 in the range of \$7 million to \$9 million, compared to insignificant net cash taxes in 2009. Included in 2010 corporate-level costs will be the \$5 million payment under the terms of the management agreement termination, compared to a \$6 million payment in 2009.

Looking ahead to 2011, we expect overall levels of cash flow to be improved over projected 2010 levels. Higher distributions from existing projects, initial distributions from our recent investment in Idaho Wind and a slightly lower payment under the management agreement termination are expected to be partially offset by the non-recurrence of the cash tax refunds that are anticipated in 2010. In 2012, still higher distributions from projects are expected to further increase operating cash flow compared to 2011. The most significant factor in the expected higher operating cash flow in 2012 is increased distributions from Selkirk following the final payment of its non-recourse project-level debt in 2012.

The following one-time items and contract expirations comprise the most significant of the decreases in projected 2010 project distributions compared to 2009.

- > Final insurance proceeds received in 2009 at Orlando due to the unplanned outage in early 2008.
- > Increase in debt principal payments in 2010 for Auburndale project-level debt.
- > Resolution in 2009 of the landowner litigation over right-of-way issues at Path 15, which resulted in \$6 million being released from the construction reserve account.
- > Final payment related to Pasco's prior PPA that expired at end of 2008 was received in early 2009.

In 2009, the following five projects comprised approximately 86% of project distributions received: Auburndale, Lake, Orlando, Path 15 and Pasco. For 2010, we expect these same five projects to contribute approximately 90% of total project distributions.

In addition to the items above, the following is a summary of other projections for project distributions in 2010 and beyond:

Lake

The Lake project is exposed to changes in natural gas prices from the expiration of its natural gas supply contract on June 30, 2009 through the expiration of its PPA in July 2013. We have executed a hedging strategy to mitigate this exposure by periodically entering into financial swaps that effectively fix the forward price of natural gas required at the project. We have taken advantage of the low market price of natural gas to make significant progress in our natural gas hedging strategy. These hedges are summarized below under "Quantitative and qualitative disclosures about market risk." We intend to continue, when appropriate, to evaluate opportunities to further mitigate natural gas price exposure at Lake in the 2010 to 2013 period, but do not intend to execute additional hedges at Lake for 2010 or 2012 because our natural gas exposure for those years is already substantially hedged.

The variable energy revenues in the Lake project's PPA are indexed to the price of coal consumed by a specific utility plant in Florida, PEF's Crystal River facility. The components of this coal price are proprietary to the utility, but we believe that the utility purchases coal for that plant under a combination of short to medium term contracts and spot market transactions.

Coal prices used in the electricity revenue component of the projected distributions from the Lake project incorporate a forecast of the applicable Crystal River facility coal cost provided by the utility

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based on their internal projections. The projected annual cash distributions change by approximately \$1.0 million for every \$0.25/Mmbtu change in the projected price of coal.

We expect to receive distributions from the Lake project of approximately \$27 million to \$29 million in 2010. In 2011 and 2012, distributions from Lake are expected to be \$30 million to \$34 million per year. The increases in 2011 and 2012 are primarily due to higher expected contractual capacity and energy revenue and lower natural gas prices than in 2010.

Auburndale

Based on the current forecast, we expect distributions from Auburndale of \$25 million to \$27 million per year from 2010 through 2013, when the project's current PPA expires. Distributions received from Auburndale in the 2010 through 2013 period will be impacted by projected coal and gas prices in the forecast period.

The projected revenue from the Auburndale PPA contains a component related to coal costs at the utility off-taker's Crystal River facility as described above for the Lake project. Because that mechanism does not pass through changes in the project's fuel costs, Auburndale's operating margin is exposed to changes in natural gas prices for approximately 20% of its natural gas requirements through the expiration of the gas contract. The remaining 80% of the project's fuel requirements are supplied under an agreement with fixed prices through its expiration in mid-2012. We have been executing a strategy to mitigate the future exposure to changes in natural gas prices at Auburndale by periodically entering into financial swaps that effectively fix the forward price of natural gas required at the project. See "Quantitative and qualitative disclosures about market risk" for additional details about hedge contracts executed as of August 9, 2010. The 2010 and 2011 natural gas price exposure at Auburndale has been substantially hedged. We intend to continue, when appropriate, to evaluate opportunities to further mitigate natural gas price exposure at Auburndale in the 2012 to 2013 period.

Chambers

As expected, we have reported a significant decrease in cash flow at the Chambers project in 2009 due to a planned major maintenance outage, changes in market power prices and expected sales volumes and the expense associated with regional carbon allowance purchases.

As previously reported, the reduced cash flows resulted in the project not meeting cash flow coverage ratio tests in its non-recourse debt, so we received no distributions from Chambers in 2009 and do not expect to receive distributions from Chambers in 2010. Based on our current projections, we expect to resume receiving distributions from the project in 2011 based on meeting the required debt service coverage ratios.

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The following table and discussion is a summary of our consolidated results of operations for the three years ended December 31, 2009 and the six months ended June 30, 2010 and 2009. The results of operations by segment are discussed in further detail following this consolidated overview discussion.

	Year ended December 31,			Six months ended June 30,	
	2009	2008	2007	2010	2009
	(unaudited)				
	(in thousands of U.S. dollars, except as otherwise stated)				
Project revenue					
Auburndale	\$ 74,875	\$ 10,003	\$	\$ 40,037	\$ 37,989
Lake	62,285	61,610	53,210	34,083	31,104
Pasco	11,357	58,897		5,632	5,795
Path 15	31,000	31,528	34,524	15,373	15,416
Chambers					
Other Project Assets		11,774	25,523		
	179,517	173,812	113,257	95,125	90,304
Project expenses					
Auburndale	59,435	7,669		30,133	29,324
Lake	47,005	39,951	36,429	24,007	21,049
Pasco	11,044	48,098		4,707	4,419
Path 15	11,819	10,573	10,834	5,452	5,894
Chambers					
Other Project Assets	(254)	41	3,571	173	(163)
	129,049	106,332	50,834	64,472	60,523
Project other income (expense)					
Auburndale	(4,950)	(225)		(5,695)	(1,314)
Lake	(5,060)	33	(8,563)	(6,220)	(56)
Pasco	25	(4,356)	6,159		67
Path 15	(11,682)	(13,232)	(12,016)	(6,242)	(5,215)
Chambers	6,599	16,250	16,601	5,103	422
Other Project Assets	13,015	(24,944)	5,514	1,806	2,310
	(2,053)	(26,474)	7,695	(11,248)	(3,786)
Total project income (loss)					
Auburndale	10,490	2,109		4,209	7,351
Lake	10,220	21,692	8,218	3,856	9,999
Pasco	338	6,443	6,159	925	1,443
Path 15	7,499	7,723	11,674	3,679	4,307
Chambers	6,599	16,250	16,601	5,103	422
Other Project Assets	13,269	(13,211)	27,466	1,633	2,473
	48,415	41,006	70,118	19,405	25,995

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	Year ended December 31,			Six months ended June 30,	
	2009	2008	2007	2010	2009
	(unaudited)				
	(in thousands of U.S. dollars, except as otherwise stated)				
Administrative and other expenses (income)					
Management fees and administration	26,028	10,012	8,185	7,943	5,484
Interest, net	55,698	43,275	44,307	5,312	20,170
Foreign exchange loss (gain)	20,506	(47,247)	30,142	2,432	9,506
Other expense, net	362	425	975	(26)	(30)
Total administrative and other expenses	102,594	6,465	83,609	15,661	35,130
(Loss) income from operations before income taxes	(54,179)	34,541	(13,491)	3,744	(9,135)
Income tax expense (benefit)	(15,693)	(13,560)	17,105	8,491	(2,649)
Net (loss) income	(38,486)	48,101	(30,596)	(4,747)	(6,486)
Less: Net loss attributable to non controlling interest				(129)	
Net income (loss) attributable to Atlantic Power Corporation shareholders	\$ (38,486)	\$ 48,101	\$ (30,596)	\$ (4,618)	\$ (6,486)

Consolidated overview

We have six reportable segments: Auburndale, Chambers, Lake, Pasco, Path 15 and Other Project Assets. The results of operations are discussed below by reportable segment.

Project income is the primary GAAP measure of our operating results and is discussed in "Project income" 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 "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 \$66.3 million, \$91.0 million and \$58.5 million for the years ended December 31, 2009, 2008 and 2007, respectively. Cash available for distribution was \$25.3 million and \$39.3 million for the six months ended June 30, 2010 and 2009, respectively. See "Cash available for distribution" on page 57 for additional information.

Income (loss) from operations before income taxes for the years ended December 31, 2009, 2008 and 2007 was \$(54.2) million, \$34.5 million and \$(13.5) million, respectively. Income (loss) from operations before income taxes for the six months ended June 30, 2010 and 2009 was \$3.7 million and \$(9.1) million, respectively. See "Project income" below for additional information.

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Income tax benefit was \$15.7 million for the year ended December 31, 2009 compared to an income tax benefit of \$13.6 million for the year ended December 31, 2008 and an income tax expense of \$17.1 million for the year ended December 31, 2007. Income tax expense was \$8.5 million for the six months ended June 30, 2010 compared to an income tax benefit of \$2.6 million for the six months ended June 30, 2009. Our 2009 effective tax rate was 29 percent compared to negative 39 percent

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in 2008 and negative 127 percent in 2007. Our effective tax rate for the year ended December 31, 2009 was impacted by the recognition of a future tax benefit for net operating loss carryforwards in Canada due to an anticipated increase in Canadian taxable income in future years. Our effective tax rate for the year ended December 31, 2008 resulted primarily from the decrease in valuation allowance attributable to the increase in the deferred tax liability associated with unrealized foreign exchange gains and the effect of other permanent differences. Our effective tax rate for the year ended December 31, 2007 was impacted by the increase in valuation allowance attributable to an increase in net operating loss carryforwards in Canada partially offset by branch profits taxes on current year earnings, the impact of foreign earnings subject to tax at lower rates and the effect of other permanent differences. Our effective tax rate for the six months ended June 30, 2010 was impacted by a \$2.0 million increase in the valuation allowance, a \$3.3 million permanent difference related to the estimated percentage ownership at Selkirk based on the priority distribution computation, \$0.5 million for dividend withholding taxes and \$1.2 million of various other permanent differences.

Six months ended June 30, 2010 compared with six months ended June 30, 2009**Project income***Auburndale segment*

Project income (loss) for our Auburndale segment decreased \$3.2 million to \$4.2 million in the six-month period ended June 30, 2010 from \$7.4 million in the comparable 2009 period. The decrease in project income for the six months ended June 30, 2010 is primarily attributable to the \$4.8 million non-cash change in fair value of derivative instruments associated with its natural gas swaps. These swaps were executed to financially hedge the project's exposure to the changes in market prices of natural gas. See "Quantitative and qualitative disclosures about market risk" below for additional details about our derivative instruments and other financial instruments. In addition, operations and maintenance costs were lower at Auburndale in the 2010 period due to timing.

Lake segment

Project income for our Lake segment decreased \$6.1 million to \$3.9 million in the six-month period ended June 30, 2010 from \$10.0 million in the comparable 2009 period. The decrease is primarily attributable to the non-cash change in fair value of derivative instruments associated with its natural gas swaps. These swaps were executed to financially hedge the project's exposure to the changes in market prices of natural gas. See "Quantitative and qualitative disclosures about market risk" below for additional details about our derivative instruments and other financial instruments.

Pasco segment

Project income for our Pasco segment decreased \$0.5 million to \$0.9 million in the six-month period ended June 30, 2010 from \$1.4 million in the comparable 2009 period. The decrease in project income at Pasco is attributable to the timing of operation and maintenance costs during the first quarter of 2009.

Path 15 segment

Project income for our Path 15 segment decreased \$0.6 million to \$3.7 million in the six-month period ended June 30, 2010 from \$4.3 million in the comparable 2009 period. The decrease in project income at Path 15 is attributable to a non-recurring gain in prior year related to the settlement of disputes with landowners over right-of-way issues.

Chambers segment

Project income for our Chambers segment, which is recorded under the equity method of accounting, increased \$4.7 million to \$5.1 million in the six-month period ended June 30, 2010 from \$0.4 million in the comparable 2009 period. The increase in project income at Chambers is primarily attributable to the non-recurrence of the planned major maintenance outage during the second quarter of 2009.

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Other Project Assets segment

Project income for our Other Project Assets segment decreased \$0.9 million, to \$1.6 million for the six months ended June 30, 2010 compared to a \$2.5 million income in the comparable 2009 period. While the overall change in project income for the segment was not significant, the largest components of the change are as follows:

- > the absence of revenue at Rumford in 2010 as the contract that provided substantially all of the project's cash flow expired in the fourth quarter 2009; and
- > combined losses in the 2009 period of \$1.6 million at the Mid-Georgia and Stockton projects, which were sold in the fourth quarter of 2009.

Administrative and other expenses (income)

Management fees and administration increased \$2.4 million to \$7.9 million for the six months ended June 30, 2010 from \$5.5 million in the comparable period in 2009. The increase is primarily attributable to higher employee share-based compensation plan expense in 2010. The expense associated with the plan varies, in part, with the market price of our common shares, which increased significantly during the first half of 2010 compared to the first half of 2009, resulting in higher expense in the 2010 period. In addition, we incurred expenses associated with our initial NYSE listing completed in July 2010 as well as an increase in business development costs during 2010.

Interest expense at the corporate level in 2010 primarily relates to our convertible debentures. Interest expense decreased \$14.9 million to \$5.3 million in 2010 from \$20.2 million in 2009. This decrease is primarily due to the extinguishment of the subordinated notes that were outstanding during 2009. In November 2009 we completed our common share conversion, which resulted in the extinguishment of Cdn\$348 million principal value of 11% subordinated notes due 2016 that previously formed a part of each IPS.

Foreign exchange loss (gain) primarily reflects the unrealized impact of changes in foreign exchange rates on the U.S. dollar equivalent of our Canadian dollar-denominated obligations to holders of the convertible debentures and, through 2009, our subordinated notes. In addition, unrealized and realized gains and losses on our forward contracts for the purchase of Canadian dollars to satisfy these obligations and our dividends to shareholders are included in foreign exchange loss (gain). Foreign exchange loss decreased \$7.1 million to a \$2.4 million loss in 2010 compared to a \$9.5 million loss in 2009. The U.S. dollar to Canadian dollar exchange rate increased by 1.3% during the six months ended June 30, 2010. During the six months ended June 30, 2009, the rate decreased by 4.7%. See "Quantitative and qualitative disclosures about market risk" below for additional details about our management of foreign currency risk and the components of the foreign exchange loss (gain) recognized during the six months ended June 30, 2010 compared to the foreign exchange loss (gain) in the comparable period of 2009.

Year ended December 31, 2009 vs. year ended December 31, 2008

Project income

Auburndale segment

Project income for our Auburndale segment increased \$8.4 million to \$10.5 million in 2009 from \$2.1 million in 2008. The increase in project income for the twelve months ended December 31, 2009 was attributable to the fact that 2009 was the first full year of ownership of the project. The Auburndale project was acquired in November 2008.

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Lake segment

Project income for our Lake segment decreased \$11.5 million, or 53%, to \$10.2 million in 2009 from \$21.7 million in 2008. The decrease was primarily attributable to higher fuel expense at Lake due to the expiration of its natural gas supply agreement as of June 30, 2009. A new gas supply agreement at higher prices was effective for the second half of 2009. In addition, non-cash losses associated with natural gas swaps were recorded in the change in fair value of derivative instruments during 2009 of \$5.1 million. These swaps were executed to financially hedge the project's exposure to the changes in market prices of natural gas. See "Quantitative and qualitative disclosures about market risk" below for additional details about our derivative instruments and other financial instruments.

Pasco segment

Project income for our Pasco segment decreased \$6.1 million, or 95%, to \$0.3 million in 2009 from \$6.4 million in 2008. The decrease in project income at Pasco was attributable to lower revenues of \$47.5 million from the project's new ten-year tolling agreement effective January 1, 2009, which provides for lower rates than the power purchase agreement that expired December 31, 2008, partially offset by lower fuel expense of \$26.7 million, since the new agreement requires the utility to provide the natural gas needed to generate electricity at the plant. In addition, depreciation expense decreased by \$8.2 million due to the full amortization of the intangible asset associated with the project's PPA that expired on December 31, 2008. The Pasco project also recorded a \$3.4 million charge in change in fair value of derivative instruments in 2008 associated with natural gas swaps that terminated at the end of 2008.

Path 15 segment

Project income at Path 15 for the year ended December 31, 2009 did not change significantly from 2008.

Chambers segment

Project income for our Chambers segment, which is recorded under the equity method of accounting, decreased \$9.7 million, or 59%, to \$6.6 million in 2009 from \$16.3 million in 2008 as a result of \$9.4 million lower gross margin due to lower electricity sales volumes and prices throughout 2009 and a \$4.6 million increase in operation and maintenance costs from a planned major maintenance outage in the second quarter of 2009. In addition, non-cash gains of \$2.6 million associated with interest swaps were recorded in the change in fair value of derivative instruments during 2009 compared to \$4.3 million of losses in 2008.

Other Project Assets segment

Project income (loss) for our Other Project Assets segment increased \$26.5 million to \$13.3 million in 2009 compared to a \$(13.2) million loss in 2008, primarily due to the following:

- > the gain on the sale of Mid-Georgia of \$15.8 million in 2009;
- > an impairment charge of \$18.5 million at Stockton in 2008;
- > the absence of revenue at Onondaga in 2009 as the contract that provided substantially all of the project's cash flow expired in the second quarter 2008;
- > reduced expense at Selkirk in 2009 associated with the change in fair value of derivative instruments; and
- > an impairment of our equity investment in Rumford of \$5.5 million in 2009.

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Administrative and other expenses (income)

Management fees and administration expenses includes the costs of operating as a public company, as well as the fees and costs associated with our management by Atlantic Power Management, LLC (the "Manager"). Effective December 31, 2009, the Manager no longer provides management and administrative services for our company. The Manager is indirectly owned by the ArcLight Funds and received compensation in the form of an annual base fee that was indexed to inflation and an incentive fee that was equal to 25% of the cash distributions to shareholders in excess of Cdn\$1.00 per year per IPS. We also reimbursed the Manager for reasonable costs incurred to manage our company. Management fees and administration increased \$16 million, or 160%, to \$26 million in 2009 from \$10.0 million in 2008. The increase is primarily attributable to a \$14.1 million charge associated with the termination of the management agreements at the end of 2009. In addition, employee and director share-based compensation plan expense increased in 2009. The expense associated with these plans varies, in part, with the market price of our common shares, which increased significantly during 2009 compared to a decrease during the twelve months of 2008, resulting in higher expense in the 2009 period.

Interest expense primarily relates to required interest costs associated with the subordinated notes and the debentures. Interest expense increased \$12.4 million, or 29%, to \$55.7 million in 2009 from \$43.3 million in 2008. This increase is primarily due to the write off of unamortized subordinated note deferred finance costs of \$7.5 million, the write off of the unamortized subordinated note premium of \$0.9 million and transaction costs of \$4.7 million upon closing of our conversion to a common share structure. A charge of \$3.1 million was also recorded when we redeemed the remaining subordinated notes in December 2009. This charge was comprised of a premium paid on the redemption of \$1.9 million and the write-off of unamortized subordinated note deferred finance costs of \$1.2 million. In addition, there were amounts outstanding on our revolving credit facility for a portion of the year ended December 31, 2009 related to the temporary financing of the acquisition of the Auburndale project in late 2008.

Foreign exchange loss (gain) primarily reflects the unrealized impact of changes in foreign exchange rates on the U.S. dollar equivalent of our Canadian dollar-denominated obligations to holders of subordinated notes and debentures. In addition, unrealized and realized gains and losses on our forward contracts for the purchase of Canadian dollars to satisfy these obligations are included in foreign exchange loss (gain). Foreign exchange loss (gain) increased \$67.7 million to \$20.5 million loss in 2009 compared to a \$(47.2 million) gain in 2008. The U.S. dollar to Canadian dollar exchange rate decreased by 15.9% during the year ended December 31, 2009. During the year ended December 31, 2008, the rate increased by 18.6%. See "Quantitative and qualitative disclosures about market risk" below for additional details about our management of foreign currency risk and the components of the foreign exchange loss (gain) recognized during the year ended December 31, 2009 compared to the foreign exchange loss (gain) in 2008.

Year ended December 31, 2008 vs. December 31, 2007

Project income

Auburndale segment

The Auburndale project was acquired in November 2008 and had no results of operations for the year ended December 31, 2007.

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Lake segment

Project income for our Lake Segment increased \$13.5 million, or 164%, to \$21.7 million in 2008 from \$8.2 million in 2007 primarily due to higher dispatch in 2008, a 5% increase in capacity payments under the PPA and the non-recurrence of costs associated with a planned outage for a gas turbine upgrade during the fourth quarter of 2007.

Pasco segment

Project income for our Pasco Segment increased \$0.2 million to \$6.4 million in 2008 from \$6.2 million in 2007 due to an increase in ownership of the project from 50% in 2007 to 100% in 2008, offset by higher fuel costs related to gas swap payments and an overhaul of the steam turbine during the fourth quarter of 2008.

Path 15 segment

Project income for our Path 15 Segment decreased \$4 million, or 34%, to \$7.7 million in 2008 from \$11.7 million in 2007 as a result of lower revenues associated with the 2008-2010 rate case and a provision for rate case refund.

Chambers segment

Project income for our Chambers Segment decreased \$0.3 million, or 2%, to \$16.3 million in 2008 from \$16.6 million in 2007 primarily due to timing differences of coal prices between the PPA and project fuel agreement.

Other Project Assets segment

Project income (loss) for our Other Project Assets segment decreased \$40.7 million, or 148%, to a \$(13.2) million loss in 2008 compared to \$27.5 million income in 2007, primarily due to the following:

- > an impairment charge at Stockton in 2008 in the amount of \$18.5 million;
- > lower income at Selkirk attributable to a decrease in the fair value of its long-term gas supply agreement, which is recorded as a derivative instrument; and
- > the absence of revenue at Onondaga for the second half of 2008 as the contract that provided substantially all of the project's cash flow expired in June 2008.

Administrative and other expenses

Management fees and administration increased \$1.8 million, or 22%, to \$10.0 million in 2008 from \$8.2 million in 2007. The increase is primarily attributable to costs associated with pursuing acquisitions that were not completed in 2008, as well as personnel additions and expense recognized related to awards under our long-term incentive plan that were granted in March 2008 and March 2007.

Interest expense decreased \$1.0 million, or 2%, to \$43.3 million in 2008 from \$44.3 million in 2007. Interest expense primarily relates to required interest payments to holders of the subordinated notes and the debentures. In addition, there were amounts outstanding on the revolving credit facility during the first half of 2007 related to the temporary financing of the acquisition of the Path 15 project, as well as amounts outstanding as of December 31, 2008 on the revolving credit facility due to the acquisition of Auburndale.

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Foreign exchange loss (gain) increased \$77.3 million to a \$(47.2 million) gain in 2008 compared to a \$30.1 million loss in 2007. The increase in foreign exchange loss (gain) is due primarily to an increase in the U.S. dollar to Canadian dollar exchange rate of approximately 18.6% during the year ended December 31, 2008. The rate decreased by 17% during the year ended December 31, 2007. See "Quantitative and qualitative disclosures about market risk" for additional details about our management of foreign currency risk and the components of the foreign exchange gains recognized during the year ended December 31, 2008 compared to the foreign exchange losses in the prior year periods.

Supplementary non-GAAP financial information

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

The primary factor influencing cash available for distribution is cash distributions received from the projects. These distributions received are generally funded from Project Adjusted EBITDA generated by the projects, reduced by project-level debt service and capital expenditures, and adjusted for changes in project-level working capital and cash reserves. Project Adjusted EBITDA is defined as project income less 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. Investors are cautioned that we may calculate this measure in a manner that is different from other companies.

Because Project Adjusted EBITDA and project distributions are key drivers of both the performance of our projects and cash available for distribution, please see the following supplementary unaudited non-GAAP information that summarizes Project Adjusted EBITDA by project and a reconciliation of Project Adjusted EBITDA by project to project distributions actually received by us.

Table of Contents**Management's discussion and analysis of financial condition and results of operations****PROJECT ADJUSTED EBITDA (IN THOUSANDS OF U.S. DOLLARS)**

(unaudited)	Year ended December 31,			Six months ended June 30,	
	2009	2008	2007	2010	2009
Project adjusted EBITDA by individual segment					
Auburndale	35,221	4,461		19,802	18,547
Lake	25,378	32,892	28,042	14,612	15,621
Pasco	3,299	21,953	14,225	2,417	2,869
Path 15	27,691	28,872	31,564	14,115	13,833
Chambers	13,595	27,603	28,028	10,129	5,024
Total	105,184	115,781	101,859	61,075	55,894
Other Project Assets					
Mid-Georgia	2,509	4,206	5,587		1,386
Stockton	(675)	1,780	3,505		(1,114)
Badger Creek	3,245	3,762	4,109	1,510	1,732
Koma Kulshan	822	912	1,196	553	412
Onondaga		7,865	21,966		
Orlando	8,858	8,206	8,336	3,671	3,975
Topsham	1,879	2,629	2,031	963	1,118
Delta Person	894	2,012	2,255	904	824
Gregory	4,482	5,236	4,428	2,283	2,271
Rumford	2,590	2,395	2,585	(7)	1,308
Selkirk	15,059	19,104	24,197	7,056	7,650
Rollcast	(234)			(189)	(95)
Other	(434)	801	3,164	(544)	(306)
Total adjusted EBITDA from Other Project Assets segment	38,995	58,908	83,359	16,200	19,161
Project income					
Total adjusted EBITDA from all projects	144,179	174,689	185,218	77,275	75,055
Amortization	67,643	60,125	59,141	32,982	35,005
Interest expense, net	31,511	30,316	31,678	11,878	15,613
Change in the fair value of derivative instruments	5,047	29,914	22,440	12,729	(589)
Other (income) expense	(8,437)	13,328	1,841	281	(969)
Project income as reported in the statement of operations	48,415	41,006	70,118	19,405	25,995

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**RECONCILIATION OF PROJECT DISTRIBUTIONS (IN THOUSANDS OF U.S. DOLLARS)
FOR THE SIX MONTHS ENDED JUNE 30, 2010**

(unaudited)	Project adjusted EBITDA	Repayment of long-term debt	Interest expense, net	Capital expenditures	Change in working capital & other items	Project distribution received
Reportable segments						
Auburndale	19,802	(4,900)	(886)	(8)	(1,008)	13,000
Chambers	10,129	(6,016)	(3,327)	(34)	(742)	
Lake	14,612		6	(1,004)	748	14,362
Pasco	2,417			(467)	380	2,330
Path 15	14,115	(3,740)	(6,242)		181	4,314
Total reportable segments	61,075	(14,666)	(10,449)	(1,513)	(441)	34,006
Other Project Assets						
Badger Creek	1,510		(7)		138	1,641
Delta Person	904	(1,023)	(137)		256	
Gregory	2,283	(823)	(112)	(39)	(443)	866
Koma Kulshan	553				(206)	347
Orlando	3,671		1	(66)	(1,706)	1,900
Rumford	(7)				7	
Selkirk	7,056	(4,657)	(1,181)	(309)	(909)	
Topsham	963					963
Other	(733)		7	(40)	792	26
Total Other Project Assets segment	16,200	(6,503)	(1,429)	(454)	(2,071)	5,743
Total all segments	77,275	(21,169)	(11,878)	(1,967)	(2,512)	39,749

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**RECONCILIATION OF PROJECT DISTRIBUTIONS (IN THOUSANDS OF U.S. DOLLARS)
FOR THE SIX MONTHS ENDED JUNE 30, 2009**

(unaudited)	Project adjusted EBITDA	Repayment of long-term debt	Interest expense, net	Capital expenditures	Change in working capital & other items	Project distribution received
Reportable segments						
Auburndale	18,547	(1,750)	(1,314)	(246)	(2,364)	12,873
Chambers	5,024	(5,303)	(4,029)	(525)	4,833	
Lake	15,621		6	(426)	309	15,510
Pasco	2,869		43	(46)	4,084	6,950
Path 15	13,833	(3,801)	(6,444)		5,194	8,782
Total reportable segments	55,894	(10,854)	(11,738)	(1,243)	12,056	44,115
Other Project Assets						
Mid-Georgia	1,386	(816)	(1,734)		1,164	
Stockton	(1,114)		(35)	96	1,053	
Badger Creek	1,732		(2)		(130)	1,600
Delta Person	824	(541)	(190)		(93)	
Gregory	2,271	(2,132)	(221)	(46)	728	600
Koma Kulshan	412			(18)	(327)	67
Orlando	3,975		6	(189)	2,658	6,450
Rumford	1,308				(1,308)	
Selkirk	7,650	(4,247)	(1,586)	(59)	1,238	2,996
Topsham	1,118	(45)	(2)			1,071
Other	(401)		(111)	(46)	1,091	533
Total Other Project Assets segment	19,161	(7,781)	(3,875)	(262)	6,074	13,317
Total all Segments	75,055	(18,635)	(15,613)	(1,505)	18,130	57,432

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**RECONCILIATION OF PROJECT DISTRIBUTIONS (IN THOUSANDS OF U.S. DOLLARS)
FOR THE TWELVE MONTHS ENDED DECEMBER 31, 2009**

(unaudited)	Project adjusted EBITDA	Repayment of long-term debt	Interest expense, net	Capital expenditures	Change in working capital & other items	Project distribution received
Reportable segments						
Auburndale	35,221	(3,500)	(2,832)	(322)	2,419	30,986
Chambers Lake	13,595	(10,570)	(7,674)	(689)	5,338	
	25,378		4	(1,278)	(1,405)	22,699
Pasco	3,299			(97)	5,148	8,350
Path 15	27,691	(7,519)	(12,912)		3,798	11,058
Total reportable segments	105,184	(21,589)	(23,414)	(2,386)	15,298	73,093
Other Project Assets						
Mid-Georgia	2,509	(1,694)	(3,271)	11	2,445	
Stockton	(675)		(70)	(297)	1,042	
Badger Creek	3,245		(17)		447	3,675
Delta Person	894	(1,512)	(224)		842	
Gregory	4,482	(2,903)	(1,792)	(98)	2,551	2,240
Koma Kulshan	822		1	(79)	(553)	191
Orlando	8,858		14	(632)	4,435	12,675
Rumford	2,590		2		309	2,901
Selkirk	15,059	(8,122)	(2,777)	161	(1,325)	2,996
Topsham	1,879	(45)	(2)			1,832
Other	(668)		39	(62)	1,248	557
Total Other Project Assets Segment	38,995	(14,276)	(8,097)	(996)	11,441	27,067
Total all Segments	144,179	(35,865)	(31,511)	(3,382)	26,739	100,160

Table of Contents**Management's discussion and analysis of financial condition and results of operations****RECONCILIATION OF PROJECT DISTRIBUTIONS (IN THOUSANDS OF U.S. DOLLARS)
FOR THE TWELVE MONTHS ENDED DECEMBER 31, 2008**

(unaudited)	Project adjusted EBITDA	Repayment of long-term debt	Interest expense, net	Capital expenditures	Change in working capital & other items	Project distribution received
Reportable segments						
Auburndale	4,461		(225)		1,764	6,000
Chambers	27,603	(9,639)	(8,537)	(145)	1,414	10,696
Lake	32,892		33	(814)	(931)	31,180
Pasco	21,953	(12,038)	(978)	(175)	10,883	19,645
Path 15	28,872	(8,086)	(13,232)		156	7,710
Total Reportable segments	115,781	(29,763)	(22,939)	(1,134)	13,286	75,231
Other Project Assets						
Mid-Georgia	4,206	(2,646)	(3,271)	11	1,700	
Stockton	1,780		(9)	(61)	(1,460)	250
Badger Creek	3,762		(3)		441	4,200
Delta Person	2,012	(1,027)	(738)		(247)	
Gregory	5,236	(1,807)	288	(133)	6,827	10,411
Koma Kulshan	912		4	(192)	(528)	196
Onondaga	7,865		81	(3)	11,693	19,636
Orlando	8,206	(3,468)	16	(306)	(1,048)	3,400
Rumford	2,395		2	(187)	524	2,734
Selkirk	19,104	(6,915)	(3,403)	(60)	(695)	8,031
Topsham	2,629	(2,400)	(193)		(36)	
Other	801		(151)	(113)	(137)	400
Total Other Project Assets segment	58,908	(18,263)	(7,377)	(1,044)	17,034	49,258
Total all segments	174,689	(48,026)	(30,316)	(2,178)	30,320	124,489

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**RECONCILIATION OF PROJECT DISTRIBUTIONS (IN THOUSANDS OF U.S. DOLLARS)
FOR THE TWELVE MONTHS ENDED DECEMBER 31, 2007**

(unaudited)	Project adjusted EBITDA	Repayment of long-term debt	Interest expense, net	Capital expenditures	Change in working capital & other items	Project distribution received
Reportable segments						
Auburndale						
Chambers	28,028	(9,331)	(11,549)	(316)	(264)	6,568
Lake	28,042	(574)	106	(13,879)	11,755	25,450
Pasco	14,225	(7,226)	(395)	(836)	6,267	12,035
Path 15	31,564	(11,842)	(11,217)		(3,213)	5,292
Total reportable segments	101,859	(28,973)	(23,055)	(15,031)	14,545	49,345
Other Project Assets						
Mid-Georgia	5,587	(2,411)	(3,589)		413	
Stockton	3,505		(24)	(391)	411	3,501
Badger Creek	4,109		43	(192)	(310)	3,650
Delta Person	2,255	(935)	(991)		762	1,091
Gregory	4,428	(377)	364		(4,415)	
Koma Kulshan	1,196	(925)	(24)	(271)	24	
Onondaga	21,966		54		(3,070)	18,950
Orlando	8,337	(3,980)	(122)	(132)	(853)	3,250
Rumford	2,585		32	(291)	475	2,801
Selkirk	24,197	(3,725)	(3,810)		(6,312)	10,350
Topsham	2,031	(1,625)	(338)		(68)	
Other	3,163	(813)	(218)	(149)	4,405	6,388
Total Other Project Assets segment	83,359	(14,791)	(8,623)	(1,426)	(8,538)	49,981
Total all segments	185,218	(43,764)	(31,678)	(16,457)	6,007	99,326

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Project operations performance six months ended June 30, 2010 compared with six months ended June 30, 2009

Aggregate Project Adjusted EBITDA increased \$2.2 million to \$77.3 million in the six months ended June 30, 2010 from \$75.1 million in the comparable 2009 period and included the following factors:

- > increased EBITDA at Chambers attributable to the non-recurrence of a planned major maintenance outage during the six months ended June 30, 2009;
- > increased EBITDA at Auburndale due to increased contractual capacity payments under the projects PPA;
- > the absence of Stockton's loss during the first half of 2009 resulting from higher maintenance costs from a forced outage during 2009. The Stockton project was sold in the fourth quarter of 2009;
- > the absence of EBITDA at Mid-Georgia as the project was sold in the fourth quarter of 2009;
- > the absence of EBITDA at Rumford in 2010 as the contract that provided substantially all of the project's cash flow expired in the fourth quarter 2009; and
- > decreased EBITDA at Lake attributable to higher fuel expense due to natural gas purchases at higher prices than those under the supply contract that expired in June 2009. We have a hedging strategy to mitigate its future exposure to changes in natural gas prices. See "Quantitative and Qualitative Disclosures About Market Risk" for additional information.

Aggregate power generation for projects in operation at June 30, 2010 was 6.6% lower during the six-month period ended June 30, 2010 compared to the first half of 2009. Weighted average plant availability increased 3.9% over the same period in 2009. Generation during the first six months of 2010 compared to the prior year period was unfavorably impacted primarily by reduced dispatch at the Chambers and Selkirk projects due to lower power prices and the absence of Stockton and Mid-Georgia generation as the projects were sold in the fourth quarter of 2009, partially offset by increased generation at Lake due to favorable market conditions in the second quarter of 2009.

The project portfolio achieved a weighted average availability of 96.9% for the six months ended June 30, 2010 compared to 93.0% in the 2009 period. The increase in portfolio availability in the first half of 2010 was primarily due to the planned outages at Gregory and Chambers in the second half of 2009. Each of the projects with reduced availability was nevertheless able to achieve substantially all of its respective capacity payments as a result of contract terms that provide for certain levels of planned and unplanned outages.

Project operations performance year ended December 31, 2009 vs. December 2008

Aggregate Project Adjusted EBITDA for the segments decreased \$30.5 million, or 17%, to \$144.2 million in 2009 from \$174.7 million in 2008 and included the following factors:

- > increased EBITDA attributable to the acquisition of the Auburndale project in November 2008;
- > decreased EBITDA at Chambers attributable to lower levels of dispatch by the utility off-taker in connection with reduced demand and lower natural gas and power prices in the region. Operating the plant at a lower capacity factor also decreased its efficiency, further contributing to reduced operating margins. Additionally, decreased EBITDA attributable to a planned major outage at Chambers in the second quarter of 2009;
- > decreased EBITDA at Lake attributable to higher fuel expense resulting due to natural gas purchases at higher prices than those under the supply contract that expired in June 2009. We

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have a hedging strategy to mitigate its future exposure to changes in natural gas prices. See "Quantitative and Qualitative Disclosures About Market Risk" for additional information;

- > decreased EBITDA at Pasco due to the commencement of the project's new ten-year tolling agreement on January 1, 2009 at lower rates than the power purchase agreement that expired December 31, 2008; and
- > the absence of EBITDA at Onondaga as the contracts that provided substantially all of the project's cash flow expired in the second quarter of 2008.

Aggregate power generation for projects in operation at December 31, 2009 was 2.6% lower during 2009 as compared to 2008. Weighted average plant availability increased 1.1% over the same period. Generation during the twelve months of 2009 versus the prior years period was unfavorably impacted primarily by reduced dispatch at Chambers. This was due to low market prices and a planned major maintenance outage, offset by the acquisition of Auburndale in November 2008. Also contributing to the lower generation during the period was reduced generation at Pasco as a result of the expected lower dispatch under the new tolling agreement that went into effect on January 1, 2009, which was partially offset by increased generation at Orlando in 2009 due to its unscheduled outage in March 2008.

The project portfolio achieved a weighted average availability of 94.5% for 2009 versus 93.4% in 2008. The higher portfolio availability was primarily driven by the increased availability of Orlando versus the prior period resulting from the March 2008 unplanned outage as well as higher availability at Mid-Georgia due to a scheduled outage in April 2008, and the acquisition of Auburndale in November 2008, offset slightly by reduced availability at Chambers associated with a longer planned outage versus the prior period. Each of the projects with reduced availability was nevertheless able to achieve substantially all of its respective capacity payments as a result of contract terms that provide for certain levels of planned and unplanned outages.

CASH FLOW FROM OPERATING ACTIVITIES

Our cash flow from the projects may vary from year to year based on, among other things, changes in prices under the PPAs, fuel supply and transportation agreements, steam sales agreements and other project contracts, changes in regulated transmission rates, compliance with the terms of non-recourse project-level financing including debt repayment schedules, the transition to market or recontracted pricing following the expiration of PPAs, fuel supply and transportation contracts, working capital requirements and the operating performance of the projects. 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.

Working capital includes trade receivables and payables at the projects.

Cash flow from operating activities increased by \$5.5 million for the six months ended June 30, 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 December 2009, which eliminated Cdn\$348 million of outstanding subordinated notes. The positive change in operating cash flow attributable to the reduced interest expense was partially offset by a \$4.5 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. The Selkirk project is currently not making distributions to partners as a result of restrictions in its non-recourse project-level debt. We expect to resume receiving distributions from

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Selkirk in 2011. An increase in corporate general administrative expenses of \$2.5 million also reduced operating cash flow in the six months ended June 30, 2010 compared to the first half of 2009.

Cash flow from operating activities decreased by \$27.3 million for the year ended December 31, 2009 as compared to 2008. The changes from the prior period are consistent with and primarily attributable to the changes in Project Adjusted EBITDA described above. In addition, the \$6.0 million payment in December 2009 under the terms of the management agreement termination reduced operating cash flow for the twelve months ended December 31, 2009.

Cash provided by operating activities for the year ended December 31, 2008 improved to \$77.8 million compared to \$58.1 million for the year ended December 31, 2007. Our improvement in cash provided by operating activities was primarily due to the addition of the Auburndale project acquired in November 2008, the acquisition of the additional 50% interest in Pasco in December 2007 as well as higher distributions from the Gregory project in 2008.

CASH FLOW FROM INVESTING ACTIVITIES

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

Cash flows used in investing activities for the six months ended June 30, 2010 were \$1.9 million compared to \$3.4 million for the six months ended June 30, 2009. We invested \$3.0 million in Rollcast during the first quarter of 2009, compared to an additional \$2.0 million investment in Rollcast during six months ended June 30, 2010. The cash consolidated in our balance sheet as a result of the additional investment in Rollcast was \$2.5 million.

Cash flows provided by investing activities for the year ended December 31, 2009 were \$25.0 million compared to cash flows used in investing activities of \$128.6 million for the year ended December 31, 2008. We sold the assets of Mid Georgia in 2009 for proceeds of \$29.1 million compared to no asset sales in 2008. In addition, we acquired Auburndale in 2008 for a total purchase price of \$141.7 million compared to no acquisitions in 2009.

Cash flows used in investing activities for the year ended December 31, 2008 were \$128.6 million compared to cash flows used in investing activities of \$18.3 million for the year ended December 31, 2007. The change in cash flows from investing activities was primarily due to the acquisition of Auburndale in 2008, for a purchase price of \$141.7 compared to the acquisition of the remaining 50% interest in the Pasco Project from our existing partners for \$23.2 million in 2007. We also sold our equity investment in the Jamaica Project in 2007 for proceeds of \$6.2 million compared to no asset sales in 2008.

CASH FLOWS FROM FINANCING ACTIVITIES

Cash used in financing activities for the six months ended June 30, 2010 resulted in a net outflow of \$20.7 million compared to a net outflow of \$21.5 million for the same period in 2009. Although the total cash used in financing activities did not change significantly in the six months ended June 30, 2010 compared to the same period in the prior year, the 2010 period included an increase in dividends paid of approximately \$20 million. We completed our common share conversion in November 2009.

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As a result, Cdn\$348 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 six months ended June 30, 2009. This increase in dividends paid was offset by the proceeds of \$20 million from a borrowing under our revolving credit facility that was used to partially fund our investment in Idaho Wind in July 2010.

Cash used in financing activities for the year ended December 31, 2009 resulted in a net outflow of \$62.9 million compared to a net inflow of \$38.4 million for the same period in 2008. Our significant cash flows from our 2009 and 2008 financing transactions are described below:

- > During the year ended December 31, 2009, we repaid \$55 million previously borrowed under our revolving credit facility that had been used to partially fund the acquisition of Auburndale in 2008.
- > During the year ended December 31, 2009, the cash used to repay project-level debt was lower compared to 2008 due to the maturity of the Pasco debt in 2008.
- > During December 2009, we issued, in a public offering, Cdn\$86.2 million aggregate principal amount of 6.25% convertible unsecured debentures for net proceeds of \$78.3 million. The proceeds were partially used to redeem the remaining Cdn\$40.7 million principal value of subordinated notes.

Cash used in financing activities for the year ended December 31, 2008 resulted in a net inflow of \$38.4 million compared to a net outflow of \$49.9 million for the same period in 2007. Our significant cash flows from our 2008 and 2007 financing transactions are described below:

- > In 2008, we acquired 100% of Auburndale. The purchase price was partially funded by a \$55 million borrowing under our credit facility and \$35 million of project-level debt.
- > In 2007, we entered into a \$48 million non-recourse term loan for the Path 15 project. This was the permanent financing arrangement for the Path 15 project which was initially financed in 2006 by an \$88 million acquisition credit facility. The acquisition credit facility was repaid in full in 2007 using \$51 million of cash on hand and funds drawn on the credit facility.
- > In early 2007, proceeds from a 2006 financing were released from escrow and used to settle an obligation to redeem the non-controlling interest in Atlantic Holdings.

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 receive monthly cash distributions in the form of dividends on the new common shares. Dividends are paid at the discretion of our board of directors based on historical and projected cash available for distribution. Cash available for distribution decreased by \$30.4 million for the year ended December 31, 2009 as compared to 2008 due primarily to the changes in cash flow from operating activities described above. In addition, project-level debt repayments were made at Auburndale, which was acquired in late 2008.

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Management's discussion and analysis of financial condition and results of operations

The table below presents our calculation of cash available for distribution for the six months ended June 30, 2010 and 2009 and the years ended December 31, 2009, 2008 and 2007 (in thousands of U.S. dollars, except as otherwise stated):

(unaudited)	Year ended December 31,			Six months ended	
	2009	2008	2007	June 30, 2010	2009
Cash flows from operating activities ⁽¹⁾	50,449	77,788	58,088	35,978	30,524
Project-level debt repayments	(12,744)	(22,275)	(20,117)	(9,141)	(6,414)
Interest on IPS portion of subordinated notes ⁽²⁾	30,639	36,560			