ATLANTIC POWER CORP
Form S-1/A
September 16, 2011

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As filed with the Securities and Exchange Commission on September 15, 2011

Registration No. 333-176257

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

AMENDMENT NO. 1
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	**4900**	**55-0886410**
(State or Other Jurisdiction of Incorporation or Organization)	(Primary Standard Industrial Classification Code Number)	(I.R.S. Employer Identification Number)

200 Clarendon St., Floor 25
Boston, Massachusetts 02116
(617) 977-2400
(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
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(Name, Address, Including Zip Code, and Telephone Number, Including Area Code, of Agent For Service)

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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: o

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. o

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. o

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. o

Indicate by check mark whether the registrant is a large accelerated filer, an accelerated filer, a non-accelerated filer, or a smaller reporting company. See the definition of "larger accelerated filer," "accelerated filer" and "smaller reporting company" in Rule 12b-2 of the Exchange Act. (Check one):

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

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.

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The information in this preliminary 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 declared effective. This preliminary prospectus is not an offer to sell these securities and it is not soliciting an offer to buy these securities in any jurisdiction where the offer or sale of such securities is not permitted.

Subject to Completion
Preliminary Prospectus dated September 15, 2011

PROSPECTUS

Shares

Common Shares

We are offering of our 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, 2011, the last reported sale price of our common shares on the New York Stock Exchange and the Toronto Stock Exchange was $14.79 and C$14.65, 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 19 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	$	$

This offering is made in contemplation of our acquisition of all the outstanding limited partnership interests in Capital Power Income L.P. pursuant to a plan of arrangement (the "Plan of Arrangement") under the Canada Business Corporations Act, as more fully described herein. We intend to use the net proceeds of this offering to finance a portion of the cash payable by us under the Plan of Arrangement. However, this offering is not conditioned on the completion of the Plan of Arrangement and there can be no assurance that the Plan of Arrangement will be completed. The shares offered hereby will remain outstanding whether or not the Plan of Arrangement is completed.

The underwriters may also purchase up to an additional 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 expect to deliver the common shares on or about , 2011.

Joint Book-Running Managers

TD Securities	**Morgan Stanley**

The date of this prospectus is , 2011.

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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. Unless otherwise noted, all references to "C$" and "Canadian dollars" are to the lawful currency of Canada and all references to "$," "US$" and "U.S. dollars" are to the lawful currency of the United States. 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 or incorporated by reference herein, before making an investment decision.

Atlantic Power Corporation

Atlantic Power Corporation owns and operates a diverse fleet of power generation and infrastructure assets in the United States. Our power generation projects sell electricity to utilities and other large commercial customers under long-term power purchase agreements ("PPAs"), which seek to minimize exposure to changes in commodity prices. Our power generation projects in operation have an aggregate gross electric generation capacity of approximately 1,948 megawatts ("MW") in which our ownership interest is approximately 871 MW. Our current portfolio consists of interests in 12 operational power generation projects across nine states, one biomass project under construction in Georgia, and a 500 kilovolt 84-mile electric transmission line located in California. We also own a majority interest in Rollcast Energy, a biomass power plant developer with several projects under development.

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

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

Our power generation projects generally operate pursuant to long-term fuel supply agreements, typically accompanied by fuel transportation arrangements. In most cases, the fuel supply and transportation arrangements correspond to the term of the relevant PPAs and many of the PPAs and steam sales agreements provide for the indexing or pass-through of fuel costs to our customers. In cases where there is no pass-through of fuel costs, we use a financial hedging strategy designed to mitigate the market price risk of fuel purchases.

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

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, telephone number (617) 977-2400. Our website is www.atlanticpower.com. Information contained on our website is not part of this prospectus.

We completed our initial public offering on the Toronto Stock Exchange ("TSX") in November 2004. At the time of our initial public offering, or IPO, our publicly traded security was an income participating security ("IPS") comprised of one common share and C$5.767 principal value of 11% subordinated notes due 2016. On November 24, 2009, our shareholders approved a conversion from the IPS structure to a traditional common share structure. Each IPS was exchanged for one new common share and each old common share that did not form 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 July 23, 2010 on the New York Stock Exchange ("NYSE") under the symbol "AT."

As described in further detail below, on June 20, 2011 we entered into an arrangement agreement, as amended effective July 25, 2011 (the "Arrangement Agreement"), pursuant to which we agreed to acquire all of the issued and outstanding limited partnership units of Capital Power Income L.P., a publicly traded Canadian partnership ("CPILP"), in exchange for up to C$506.5 million in cash and up to 31.5 million of our common shares. CPILP's current portfolio consists of 19 wholly-owned power generation assets located in both Canada and the United States, a 50.15% interest in a power generation asset in Washington State, and a 14.3% common equity interest in Primary Energy Recycling Holdings LLC. CPILP's assets have a total net generating capacity of 1,400 MW and more than four million pounds per hour of thermal energy. In addition, pursuant to the Plan of Arrangement, CPILP will sell its Roxboro and Southport facilities located in North Carolina to an affiliate of Capital Power Corporation, a publicly traded Canadian company, for approximately C$121.4 million. We cannot be certain that our acquisition of CPILP will be completed. See "Risk factors Risks related to the Plan of Arrangement."

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Our Competitive Strengths

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

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

Experienced management team. Our management team has a tremendous depth of experience in project development, asset management, mergers and acquisitions, finance and accounting. Our network of industry contacts and our reputation allow us to see proprietary acquisition opportunities on a regular basis.

Diversified projects. Our power generation projects have an aggregate gross electric generation capacity of approximately 1,948 MW, and our net ownership interest in the electric generation capacity of these projects is approximately 871 MW. These projects are diversified by fuel type, electricity and steam customers, and project operators. Many are located in the deregulated and more liquid electricity markets of California, Mid-Atlantic, New York, and Texas.

Our power transmission project, known as the Path 15 project, is an 84-mile, 500-kilovolt transmission line built in order to alleviate north-south transmission congestion in California. It is a traditional rate-base asset whose revenues are regulated by the Federal Energy Regulatory Commission ("FERC") and is owned and operated by Western, a U.S. Federal power agency. We also have a 53.5 MW biomass project under construction in Georgia.

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

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 are Progress Energy Florida, Inc. ("PEF"), Tampa Electric Company ("TECO"), and Atlantic City Electric ("ACE"), which purchase approximately 37%, 14% and 10%, respectively, of the net electric generation capacity of our projects. No other electric customer purchases more than 7% of the net electric generation capacity of our power generation projects.

Leading third-party operators. Our power generation projects utilize experienced firms for their operation and maintenance, which are recognized leaders in independent power. Affiliates of Caithness, PPMS and Babcock and Wilcox Power Generation Group, Inc. operate projects representing approximately 46%, 19% and 12%, respectively, of the net electric generation capacity of our power generation projects. No other operator is responsible for the operation of projects representing more than 8% of the net electric generation capacity of our power generation projects.

Our Objectives and Business Strategies

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

Organic growth

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

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

Extending PPAs following their expiration

PPAs in our portfolio have expiration dates ranging from 2012 to 2037. In each case, we plan for expirations by evaluating various options in the market for maximizing long-term project cash flows and passing through to purchasers as effectively as possible the potential changes in fuel costs. New arrangements may involve responses to utility solicitations for capacity and energy, direct negotiations with the original purchasing utility for PPA extensions, "reverse" request for proposals by the projects to likely bilateral counterparty arrangements with creditworthy energy trading firms for tolling agreements, full service PPAs or the use of derivatives to lock in value. We do not assume that revenues or operating margins under existing PPAs will necessarily be sustained after PPA expirations, since most original PPAs included capacity payments related to return of and return on original capital invested, and counterparties or evolving regional electricity markets may or may not provide similar payments under new or extended PPAs.

Acquisition and investment strategy

We believe that new electricity generation projects will 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. In addition, Renewable Portfolio Standards in over 31 states and the recently extended American Recovery and Reinvestment Act's 1603 grant program have greatly facilitated strong PPAs and financial returns for significant renewable project opportunities. 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 make 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 late 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 that their experience, reputation and industry relationships will provide us with enhanced access to future acquisition opportunities on a proprietary basis.

Acquisition guidelines

We use the following general guidelines when reviewing and evaluating possible acquisitions:

- each acquisition or investment should result in an increase in cash available for distribution to shareholders;

- in the case of an acquisition of power generation facilities, facilities with long-term PPAs with investment grade electrical utilities or other creditworthy customers will be preferred; and, for facilities without such agreements, market electricity price assumptions used in acquisition evaluations will be obtained from a recognized independent source; and

- the expected useful life of the facility and associated structures will, with regular maintenance, be long enough to conform with our objective of providing stable long-term dividends to shareholders.

Acquisition of Capital Power Income L.P.

The Arrangement Agreement and Plan of Arrangement

On June 20, 2011, we entered into an Arrangement Agreement, as amended effective July 25, 2011, with Capital Power Income L.P. ("CPILP"), a publicly traded Canadian limited partnership, CPILP's general partner and a related entity. The Arrangement Agreement provides that we will acquire, directly or indirectly, all of the issued and outstanding CPILP units pursuant to a plan of arrangement under the *Canada Business Corporations Act* (the "Plan of Arrangement"). Under the terms of the Plan of Arrangement, CPILP unitholders will be permitted to exchange each of their CPILP units for, at their election, C$19.40 in cash or 1.3 Atlantic Power common shares. All cash elections will be subject to proration if total cash elections exceed approximately C$506.5 million and all share elections will be subject to proration if total share elections exceed approximately 31.5 million Atlantic Power common shares.

CPILP's primary business is the ownership and operation of power plants in Canada and the United States, which generate electricity and steam, from which it derives its earnings and cash flows. The power plants generate electricity and steam from a combination of natural gas, waste heat, wood waste, water flow, coal and tire-derived fuel. CPILP's generation projects sell electricity to utilities and other large commercial customers under long-term PPAs, which seek to minimize exposure to changes in commodity prices. At present, CPILP's portfolio consists of 19 wholly-owned power generation assets located in both Canada (in the provinces of British Columbia and Ontario) and the United States (in the states of California, Colorado, Illinois, New Jersey, New York and North Carolina), a 50.15% interest in a power generation asset in Washington State, and a 14.3% common equity interest in Primary Energy Recycling Holdings LLC. CPILP's assets have a total net generating capacity of 1,400 MW and more than four million pounds per hour of thermal energy. The CPILP units trade on the TSX under the symbol "CPA.UN."

Pursuant to the Plan of Arrangement, CPILP will sell its Roxboro and Southport facilities located in North Carolina to an affiliate of Capital Power Corporation, a publicly traded Canadian company, for approximately C$121.4 million. Additionally, in connection with the Plan of Arrangement, the management agreements between certain subsidiaries of Capital Power Corporation and CPILP and certain of its subsidiaries will be terminated (or assigned) in consideration of a payment of C$10.0 million. Atlantic Power or its subsidiaries will assume the management of CPILP and intends to enter into a transitional services agreement with Capital Power Corporation for a term of up to 12 months following the completion of the Plan of Arrangement, which will facilitate the integration of CPILP into Atlantic Power. In addition, upon completion of the Plan of Arrangement, Atlantic Power will fully and unconditionally guarantee the cumulative redeemable preferred shares, Series 1, cumulative rate reset preferred shares, Series 2 and cumulative floating rate preferred shares, Series 3 issued by CPI Preferred Equity Ltd., a subsidiary of CPILP, on a subordinated basis as to: (i) payment of dividends, as and when declared; (ii) payment of amounts due on redemption; and (iii) payment of amounts due on liquidation, dissolution or winding up of CPI Preferred Equity Ltd.

The Arrangement Agreement contains customary representations, warranties and covenants. Among these covenants, CPILP and its affiliates have each agreed not to solicit alternative transactions, except that CPILP may respond to an alternative transaction proposal that constitutes, or would reasonably be expected to lead to, a superior proposal. In addition, we or CPILP may be required to pay a C$35.0 million fee if the Arrangement Agreement is terminated in certain circumstances.

We currently expect to complete the Plan of Arrangement in the fourth quarter of 2011, subject to receipt of required shareholder/unitholder, court and regulatory approvals and the satisfaction or waiver of the financing and other conditions contained in the Arrangement Agreement. However, we cannot be certain that the Plan of Arrangement will be completed. The shares offered hereby will remain outstanding whether or not the Plan of Arrangement is completed. See "Risk factors Risks related to the Plan of Arrangement."

A copy of the Arrangement Agreement, including the Plan of Arrangement, is included as an exhibit to our Current Report on Form 8-K filed with the Securities and Exchange Commission on June 24, 2011, which is incorporated by reference into this prospectus. The foregoing description of the proposed transaction and the Arrangement Agreement does not purport to be complete and is qualified in its entirety by reference to such exhibit.

Reasons for the Arrangement Agreement and Plan of Arrangement

Our board of directors believes that the combination of Atlantic Power and CPILP, if completed, will result in significant strategic benefits to the combined company. These strategic benefits include:

- Atlantic Power will become a leading publicly traded power generation and infrastructure company, with a larger and more diversified portfolio of contracted power generation assets in the United States and Canada;

- the transaction will combine Atlantic Power's proven management team with CPILP's highly qualified operations, maintenance, commercial management, accounting, human resources, legal and other personnel;

- Atlantic Power's market capitalization and enterprise value are expected to increase significantly, which is expected to add liquidity and enhance access to capital to fuel the long term growth of Atlantic Power's asset base throughout North America;

- the combination will expand and diversify Atlantic Power's asset portfolio to include projects in Canada and regions of the United States where we do not currently have a presence; and

- the transaction will further diversify the fuel types used by Atlantic Power's projects to include additional hydro, biomass and natural gas.

Our board of directors also believes that the combination of Atlantic Power and CPILP, if completed, will result in significant financial benefits to Atlantic Power's shareholders. These financial benefits include:

- upon completion of the Plan of Arrangement, our board of directors anticipates being able to increase dividends by 5%, from C$1.094 to C$1.15 per share on an annual basis;

- the transaction is expected to strengthen Atlantic Power's dividend sustainability for the foreseeable future with immediate accretion to cash available for distribution;

the transaction is expected to result in a significant improvement in Atlantic Power's dividend payout ratio starting in 2012;

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- the transaction extends Atlantic Power's average PPA term from 8.8 to 9.1 years and enhances the credit quality of Atlantic Power's power offtakers; and

- following completion of the Plan of Arrangement, we expect to benefit from cost savings attributable to synergies from combining the two entities and eliminating the public company reporting costs for CPILP.

Financing transactions

We intend to use the net proceeds from this offering to pay a portion of the cash consideration required under the Plan of Arrangement and related fees and expenses. We plan to fund the remainder of the cash consideration payable by us under the Plan of Arrangement, including related fees and expenses, with the net proceeds from a senior unsecured notes offering and/or drawings under a $625 million senior secured credit facility, each as described below.

Under a separate offering memorandum or otherwise, we may offer senior unsecured notes to fund a portion of the cash consideration payable by us under the Plan of Arrangement, pursuant to Rule 144A and Regulation S under the Securities Act of 1933, as amended (the "Securities Act"). The completion of this offering of common shares is not subject to the completion of an offering of senior unsecured notes and the completion of an offering of senior unsecured notes will not be subject to the completion of this offering. No assurance can be given that a notes offering will be commenced or completed or, if completed, as to the final terms of the notes offering.

We do not intend to register any notes under the Securities Act or the securities laws of any other jurisdiction, and notes may not be offered or sold in the United States absent registration or an applicable exemption from registration requirements. Any such notes will be offered only to qualified institutional buyers in the United States pursuant to Rule 144A under the Securities Act and outside the United States pursuant to Regulation S under the Securities Act. This description and other information regarding a possible notes offering is included in this prospectus solely for information purposes. Nothing in this prospectus should be construed as an offer to sell, or the solicitation of an offer to buy, any notes.

We have received the written commitment of a Canadian chartered bank and another financial institution to structure, arrange, underwrite and syndicate a senior secured credit facility in the amount of $625 million in order to finance the cash consideration payable by us under the Plan of Arrangement. Funding under this facility is subject to certain conditions, including, without limitation, that there shall not have occurred a material adverse effect with respect to Atlantic Power, CPILP, CPI Services Ltd. and CPI Investments Inc. taken as a whole.

The combined company

As a result of the Plan of Arrangement, if completed, we will emerge as a leading publicly traded, power generation and infrastructure company with a well diversified portfolio of assets in the United States and Canada. The transaction will increase the net generating capacity of our projects by 143% from 871 MW to approximately 2,116 MW. The combined portfolio of assets will consist of interests in 30 operational power generation projects across 11 states and two provinces, one 53.5 MW biomass project under construction in Georgia, and an 84-mile, 500 kilovolt electric transmission line located in California. We will remain headquartered in Boston and will add offices in Chicago, Toronto, Ontario and Richmond, B.C. We expect to add personnel from Capital Power Corporation who have a strong track record of managing, operating and maintaining CPILP's assets, allowing us to have direct control across the vast majority of the CPILP portfolio by taking advantage of the valuable expertise of this new personnel.

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The following map is a pro forma company structure showing the location of our projects following the Plan of Arrangement, if completed:

The following charts show the fuel type and geographic diversity of Atlantic Power and CPILP and the pro forma fuel type and geographic diversity of the combined company following the Plan of Arrangement, if completed:

(1) Includes 53.5MW Piedmont project that is currently under construction.

(2) Excludes North Carolina assets.

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The following chart shows the Standard & Poor's credit rating of the electricity purchasers, or "off takers," of the combined company following the Plan of Arrangement, if completed:

As a result of the Plan of Arrangement, if completed, we believe our larger size and broader-based ownership will improve our access to capital and facilitate the pursuit of sustained growth initiatives. Following the Plan of Arrangement, if completed, Atlantic Power will be the second largest publicly traded power generation and infrastructure company on the TSX by enterprise value.

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* Source: Bloomberg as of September 14, 2011

Power Industry Overview

Historically, the North American electricity industry was characterized by vertically-integrated monopolies. The trend towards restructuring the electric power industry and the introduction of competition in electricity generation began with the passage and implementation of the Public Utility Regulatory Policies Act of 1978. During the late 1980s, several jurisdictions began a process of restructuring by moving away from vertically integrated monopolies toward more competitive market models. Rapid growth in electricity demand, environmental concerns, increasing electricity rates, technological advances and other concerns prompted government policies to encourage the supply of electricity from independent power producers.

In the independent power generation sector, electricity is generated from a number of energy sources, including natural gas, coal, water, waste products such as biomass (e.g., wood, wood waste, agricultural waste), landfill gas, geothermal, solar and wind. According to the North American Electric Reliability Corporation's Long-Term Reliability Assessment, published in October 2010, summer peak

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demand within the United States in the ten-year period from 2010 through 2019 is projected to increase 1.3%, while winter peak demand in Canada is projected to increase 0.9%.

The non-utility power generation industry in the U.S.

Our 12 power generation projects are non-utility electric generating facilities that operate in the U.S. electric power generation industry. The electric power industry is one of the largest industries in the United States, generating retail electricity sales of approximately $353 billion in 2009, based on information published by the Energy Information Administration. A growing portion of the power produced in the United States is generated by non-utility generators. According to the Energy Information Administration, there were approximately 8,448 non-utility generators representing approximately 475 gigawatts of capacity (equal to 47% of total generating plants and 42% of nameplate capacity) in 2009, the most recent year for which data is available. Non-utility generators sell the electricity that they generate to electric utilities and other load-serving entities (such as municipalities and electric cooperatives) by way of bilateral contracts or open power exchanges. The electric utilities and other load-serving entities, in turn, generally sell this electricity to industrial, commercial and residential customers.

The power generation industry in Canada

In its 2009 outlook of Canada's energy supply, the National Energy Board of Canada ("NEB") forecast Canadian electricity production to grow at a compound average annual rate of over 1% between 2011 and 2020. The combined effect of demand growth and facility retirements is expected to result in a need for new generation in the coming years. The British Columbia and Ontario markets remain price regulated, and provincial regulatory bodies have continued to issue requests for proposals or other procurements for the development of new generation.

A major trend identified by the NEB is a push towards reducing greenhouse gas emissions. This includes energy efficiency initiatives, as well as emphasizing clean energy alternatives such as natural gas, hydro, biomass, wind, solar, nuclear and coal with carbon capture and storage technologies. Natural gas will continue to be relied upon to meet increased electricity demand. Natural gas-fired generation capacity is forecast to increase by 8,146 MW by 2020 in Canada, particularly in Ontario where 3,917 MW of combined-cycle gas and 1,337 MW of combustion turbine/cogeneration facilities will be relied on to help meet demand following the phase-out of coal-fired generation by 2014. Hydroelectric capacity is also expected to continue to be the major source of electricity with hydroelectric-based capacity projected to increase from 72,853 MW in 2008 to 80,604 MW by 2020. Extensive development of new hydro projects is expected in British Columbia, Quebec, Newfoundland and Labrador.

In addition, installed unconventional emerging technology generation continues to remain small however is expected to become a major source of generation capacity in the future. The NEB's outlook incorporates increased provincial renewable targets reflecting both increased public interest in clean sources of electricity and greater confidence on the part of system operators with their ability to integrate wind power into electric systems. Wind power is experiencing exceptionally strong growth with generation capacity projected to grow from 2,369 MW in 2008 to 16,400 MW by 2020. While wind power generation is expected to contribute the most, other generation technologies such as biomass, landfill gas, waste heat, solar and tidal are expected to contribute 3,750 MW by 2020.

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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, 2011, 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)	Net MW(2)	Primary Electricity Purchaser	Power Contract Expiry	Customer S&P Credit Rating
Auburndale	Florida	Natural Gas	155	100.00%	155	Progress Energy Florida	2013	BBB+
Lake	Florida	Natural Gas	121	100.00%	121	Progress Energy Florida	2013	BBB+
Pasco	Florida	Natural Gas	121	100.00%	121	Tampa Electric Co.	2018	BBB+
Chambers	New Jersey	Coal	262	40.00%	89	ACE(3)	2024	BBB+
					16	DuPont	2024	A
Path 15	California	Transmission	N/A	100.00%	N/A	California utilities via CAISO(4)	N/A(5)	BBB+ to A(6)
Orlando	Florida	Natural Gas	129	50.00%	46	Progress Energy Florida	2023	BBB+
					19	Reedy Creek Improvement District	2013(7)	AA-(8)
Selkirk	New York	Natural Gas	345	17.70%(9)	15	Merchant	N/A	N/R
					49	Consolidated Edison	2014	A-
Gregory	Texas	Natural Gas	400	17.10%	59	Fortis Energy Marketing and Trading	2013	AA(10)
					9	Sherwin Alumina	2020	NR
Badger Creek	California	Natural Gas	46	50.00%	23	Pacific Gas & Electric	2012(11)	BBB+
Koma Kulshan	Washington	Hydro	13	49.80%	6	Puget Sound Energy	2037	BBB
Delta-Person	New Mexico	Natural Gas	132	40.00%	53	Public Service Company of New Mexico	2020	BB-
Cadillac	Michigan	Biomass	40	100.00%	40	Consumers Energy	2028	BBB-
Idaho Wind	Idaho	Wind	183	27.56%	50	Idaho Power Co.	2030	BBB
Piedmont(12)	Georgia	Biomass	54	98.00%	53	Georgia Power	2032	A

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

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

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

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

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

(6)

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

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

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

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

(10) The guarantor under the Fortis Energy Marketing and Trading PPA is Fortis Bank S.A./N.V., which is rated AA.

(11) Entered into a one-year interim agreement in April 2011.

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

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CPILP's Power Projects

CPILP's power projects generate electricity and steam from a combination of natural gas, waste heat, wood waste, water flow, coal and tire-derived fuel. CPILP's Canadian operations consist of:

- four natural gas-fired plants with a combined generating capacity of 163 MW;
- two biomass, wood waste plants with a combined generating capacity of 101 MW; and
- two hydroelectric facilities with a combined generating capacity of 56 MW.

CPILP's United States operations consist of:

- one simple-cycle natural gas-fired power plant with a generating capacity of 300 MW;
- one combined-cycle natural gas-fired power plant with a generating capacity of 125 MW;
- seven natural gas-fired combined heat and power ("CHP") plants, three of which can also use distillate fuel, with a combined generating capacity of 440 MW and steam generating capacity of 2,537 mlbs/hr; and
- a hydroelectric plant with a total generating capacity of 60 MW.

Pursuant to the Plan of Arrangement, CPILP will sell its Roxboro and Southport facilities located in North Carolina to an affiliate of Capital Power Corporation, a publicly traded Canadian company, for approximately C$121.4 million.

The following table summarizes each of CPILP's power plants in each of Canada and the United States, and their respective operating characteristics (other than the Roxboro and Southport facilities):

Project Name	Location	Type	Net MW	Economic Interest	Primary Electric Purchaser	Power Contract Expiry	Customer S&P Credit Rating
Calstock	Ontario	Biomass	35	100%	Ontario Electricity Financial Corporation	2020	AA-
Kapuskasing	Ontario	Natural Gas	40	100%	Ontario Electricity Financial Corporation	2017	AA-
Nipigon	Ontario	Natural Gas	40	100%	Ontario Electricity Financial Corporation	2012(1)	AA-
North Bay	Ontario	Natural Gas	40	100%	Ontario Electricity Financial Corporation	2017	AA-
Tunis	Ontario	Natural Gas	43	100%	Ontario Electricity Financial Corporation	2014	AA-
Mamquam	British Columbia	Hydro	50	100%	British Columbia Hydro and Power Authority	2027(2)	AAA
Moresby Lake	British Columbia	Hydro	6	100%	British Columbia Hydro and Power Authority	2022	AAA
Williams Lake	British Columbia	Biomass	66	100%	British Columbia Hydro and Power Authority	2018(3)	AAA
Frederickson	Washington	Natural Gas	125(4)	50.15%(5)	3 Public Utility Districts(6)	2022	A to A+
Greeley	Colorado		72	100%		2013	A-

		Natural Gas			Public Service Company of Colorado		
Manchief	Colorado	Natural Gas	300	100%	Public Service Company of Colorado	2022[7]	A-
Naval Station	California	Natural Gas	47	100%	San Diego Gas & Electric	2019	A
Naval Training Centre	California	Natural Gas	25	100%	San Diego Gas & Electric	2019	A
North Island	California	Natural Gas	40	100%	San Diego Gas & Electric	2019	A
Oxnard	California	Natural Gas	49	100%	Southern California Edison	2020	BBB+
Curtis Palmer	New York	Hydro	60	100%	Niagara Mohawk Power Corp.	2027	A-
Kenilworth	New Jersey	Natural Gas	30	100%	Schering-Plough Corporation	2012[8]	AA
Morris	Illinois	Natural Gas	177	100%	Equistar Chemicals, LP[9]	2023[10]	BB-

(1) CPILP has the option to extend the PPA for ten years at existing terms.

(2) British Columbia Hydro and Power Authority ("BC Hydro") has an option exercisable in 2021 and every five years thereafter to buy the Mamquam facility or extend the contract.

(3) BC Hydro has an option to extend the agreement by up to 10 years, on the basis of two five-year term extensions.

(4) In addition, there is 10 MW duct firing.

(5) Represents CPILP's 50.15% ownership interest in Frederickson. Puget Sound Energy, Inc. owns the remaining 49.85% ownership interest.

(6) Public Utility Districts ("PUDs") are: Benton (A+), Franklin (A) and Grays Harbor (A).

(7) Public Service Company of Colorado has an option during the latter part of the extension term to purchase the Manchief facility.

(8) Pursuant to the ESA, Schering-Plough Corporation has the option to purchase the Kenilworth facility. The ESA can be extended automatically for successive five year periods.

(9) 100 MW is sold forward through April 2014 into the Pennsylvania, New Jersey, and Maryland market.

(10) Equistar Chemicals, LP has a right to purchase the Morris facility at fair market value at the end of 2013, 2018 and 2023.

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The Offering

Issuer	Atlantic Power Corporation, a British Columbia corporation.
Common shares to be offered by us	shares.
Common shares to cover over-allotments	We have granted the underwriters an option to purchase up to additional common shares to cover over-allotments.
Common shares to be outstanding after this offering	shares (or shares if the underwriters exercise their over-allotment option in full). If our acquisition of CPILP is completed, there would be approximately shares outstanding, including the approximately 31.5 million common shares we expect to issue in exchange for CPILP units in connection with the Plan of Arrangement.
Risk factors	Prospective purchasers should carefully review and evaluate certain risk factors relating to an investment in the common shares and risks related to the Plan of Arrangement. 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."
Use of proceeds	We expect to receive net proceeds from this offering of approximately $ million after deducting the underwriting discount and our estimated expenses (or approximately $ million if the underwriters exercise their over-allotment option to purchase additional shares in full). We intend to use the net proceeds from this offering to fund a portion of the cash consideration payable by us under the Plan of Arrangement and, to the extent that any proceeds remain thereafter, or the Plan of Arrangement is not completed, to fund additional growth opportunities and for general corporate purposes. This offering is not conditioned on the completion of the Plan of Arrangement and there can be no assurance that the Plan of Arrangement will be completed. The shares offered hereby will remain outstanding whether or not the Plan of Arrangement is completed. See "Use of proceeds."
Listing	Our outstanding common shares are listed on the TSX under the symbol "ATP" and on the NYSE under the symbol "AT."

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The number of common shares to be outstanding after this offering is based upon 68,984,192 shares outstanding as of September 14, 2011. Unless otherwise stated, the number of common shares to be outstanding after this offering does not include:

- approximately 31.5 million common shares we expect to issue in exchange for CPILP units in connection with the Plan of Arrangement;
- 409,295 unvested notional units granted under the terms of our Long Term Incentive Plan; and
- 13,643,645 shares issuable upon conversion, redemption, purchase for cancellation or maturity of our outstanding convertible debentures.

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Summary Historical Consolidated Financial Data of Atlantic Power

The following table presents summary consolidated financial information for Atlantic Power. The annual historical information as of December 31, 2010 and 2009 and for the years ended December 31, 2010, 2009 and 2008 has been derived from the audited consolidated financial statements appearing in Atlantic Power's Annual Report on Form 10-K for the year ended December 31, 2010, incorporated by reference into this prospectus. The annual historical information as of December 31, 2008, 2007 and 2006 and for the years ended December 31, 2007 and 2006 has been derived from historical financial statements not incorporated by reference into this prospectus. The historical information as of, and for the six-month periods ended June 30, 2011 and 2010 has been derived from the unaudited consolidated financial statements appearing in Atlantic Power's Quarterly Report on Form 10-Q for the quarter ended June 30, 2011, incorporated by reference into this prospectus. Data for all periods have been prepared under U.S. GAAP. You should read the following selected consolidated financial information together with Atlantic Power's consolidated financial statements and the notes thereto and the discussion under "Management's Discussion and Analysis of Financial Condition and Results of Operations" included as part of Atlantic Power's Annual Report on Form 10-K for the year ended December 31, 2010 and Quarterly Report on Form 10-Q for the quarter ended June 30, 2011, each of which is incorporated by reference into this prospectus. See "Where you can find more information" beginning on page 85 of this prospectus.

(in thousands of US dollars, except per	**Year Ended December 31,**					**Six Months Ended June 30,**	
share/subordinated note data and as otherwise stated)	**2010**	**2009**	**2008**	**2007**	**2006[(a)]**	**2011[(a)]**	**2010[(a)]**
Project revenue	$ 195,256	$ 179,517	$ 173,812	$ 113,257	$ 69,374	$ 106,923	$ 95,125
Project income	41,879	48,415	41,006	70,118	57,247	27,900	19,405
Net (loss) income attributable to Atlantic Power Corporation	(3,752)	(38,486)	48,101	(30,596)	(2,408)	19,322	(4,618)
Basic earnings (loss) per share	$ (0.06)	$ (0.63)	$ 0.78	$ (0.50)	$ (0.05)	$ 0.28	$ (0.08)
Basic earnings (loss) per share, C$[(b)]	$ (0.06)	$ (0.72)	$ 0.84	$ (0.53)	$ (0.06)	$ 0.28	$ (0.08)
Diluted earnings (loss) per share[(c)]	$ (0.06)	$ (0.63)	$ 0.73	$ (0.50)	$ (0.05)	$ 0.28	$ (0.08)
Diluted earnings (loss) per share, C$[(b)(c)]	$ (0.06)	$ (0.72)	$ 0.78	$ (0.53)	$ (0.06)	$ 0.28	$ (0.08)
Distribution per subordinated note[(d)]	$	$ 0.51	$ 0.60	$ 0.59	$ 0.57	$	$
Dividend declared per common share	$ 1.06	$ 0.46	$ 0.40	$ 0.40	$ 0.37	$ 0.57	$ 0.52
Total assets	$ 1,013,012	$ 869,576	$ 907,995	$ 880,751	$ 965,121	$ 1,008,980	$ 862,525
Total long-term liabilities	$ 518,273	$ 402,212	$ 654,499	$ 715,923	$ 613,423	$ 523,351	$ 407,413

(a) Unaudited.

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

(c) Diluted earnings (loss) per share is computed including dilutive potential shares, which include those issuable upon conversion of convertible debentures and under our long term incentive plan. Because we reported a loss during the years ended December 31, 2010, 2009, 2007 and 2006, and for the six-month period ended June 30, 2010, 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 incorporated by reference into this prospectus for information relating to the number of shares used in calculating basic and diluted earnings per share for the periods presented.

(d) At the time of our initial public offering, our publicly traded security was an income participating security, or an "IPS," each of which was comprised of one common share and C$5.767 principal amount of 11% subordinated notes due 2016. On November 27, 2009,we converted from the IPS structure to a traditional common share structure. In connection with the conversion, each IPS was exchanged for one new common share.

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Summary Historical Consolidated Financial Information of CPILP

The following table presents summary consolidated financial information for CPILP. The selected historical financial data as of, and for the years ended, December 31, 2010, 2009 and 2008 has been derived from CPILP's audited consolidated financial statements for those periods prepared under Canadian generally accepted accounting principles and appearing elsewhere in this prospectus. Data as of, and for the years ended, December 31, 2010 and 2009 has been reconciled to U.S. generally accepted accounting principles as noted below. The selected historical financial data as of, and for the years ended, December 31, 2007 and 2006 has been derived from the audited consolidated financial statements of CPILP prepared under Canadian generally accepted accounting principles not appearing in this prospectus. The selected historical financial data as of, and for the six-month periods ended June 30, 2011 and 2010 has been derived from CPILP's unaudited consolidated financial statements for those periods prepared using International Financial Reporting Standards and appearing elsewhere in this prospectus.

Data for all periods presented below is reported in Canadian dollars. You should read the following selected consolidated financial data together with CPILP's consolidated financial statements and the notes thereto included elsewhere in this prospectus.

(in thousands of Canadian dollars, except per unit data)	Year Ended December 31,					Six Months Ended June 30,	
	2010	2009	2008	2007	2006	2011[a][b]	2010[a][b]
Revenue	$ 532,377	$ 586,491	$ 499,267	$ 549,872	$ 326,900	$ 261,524	$ 241,453
Depreciation, amortization and accretion	$ 98,227	$ 93,249	$ 88,313	$ 85,553	$ 65,200	$ 45,461	$ 47,826
Financial charges and other, net	$ 40,179	$ 46,462	$ 94,836	$ 8,574	$ 42,200	$ 21,457	$ 21,384
Net income before tax and preferred share dividends	$ 35,224	$ 56,812	$ (91,918)	$ 108,953	$ 67,400	$ 18,741	$ 4,705
Net income (loss) attributable to equity holders of CPILP	$ 30,500	$ 57,553	$ (67,893)	$ 30,816	$ 62,121	$ 10,529	$ 8,410
Basic and diluted net income (loss) per unit, C$	$ 0.55	$ 1.07	$ (1.26)	$ 0.59	$ 1.28	$ 0.19	$ 0.15
Distributions declared per unit, C$	$ 1.76	$ 1.95	$ 2.52	$ 2.52	$ 2.52	$ 0.88	$ 0.88
Total assets	$ 1,583,910	$ 1,668,057	$ 1,809,225	$ 1,852,573	$ 1,883,400	$ 1,471,772	$ 1,667,775
Total long-term liabilities	$ 874,190	$ 853,314	$ 935,248	$ 730,940	$ 757,800	$ 821,382	$ 900,995
Operating margin[c]	$ 187,567	$ 211,680	$ 111,446	$ 216,188	$ 185,900	$ 99,675	$ 77,753

(a) Unaudited.

(b) Results have been prepared using International Financial Reporting Standards.

(c) Operating margin is a non-GAAP financial measure. CPILP uses operating margin as a performance measure. Operating margin is not a defined financial measures according to Canadian generally accepted accounting principles or International Financial Reporting Standards and does not have a standardized meaning prescribed by Canadian generally accepted accounting principles or International Financial Reporting Standards. Therefore, operating margin may not be comparable to similar measures presented by other enterprises.

Under U.S. GAAP, the following differences are noted for the years indicated below:

(in thousands of Canadian dollars, except per unit data)	Years Ended December 31,	
	2010	2009
Revenue	$ 532,377	$ 586,491
Depreciation, amortization and accretion	$ 98,277	$ 93,249
Financial charges and other, net	$ 40,179	$ 46,462
Net income before tax and preferred share dividends	$ 39,179	$ 54,753
Net income (loss) attributable to equity holders of CPILP	$ 34,455	$ 55,529
Basic and diluted net income (loss) per unit, C$	$ 0.63	$ 1.03
Distributions declared per unit, C$	$ 1.76	$ 1.95

Total assets	$	1,588,352	$	1,673,059
Total long-term liabilities	$	878,632	$	858,317
Operating margin	$	191,530	$	209,621

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Summary Unaudited Pro Forma Condensed Combined Consolidated Financial Information

The following table sets forth selected information about the pro forma financial condition and results of operations, including per share data, of Atlantic Power after giving effect to the completion of the Plan of Arrangement with CPILP. The table sets forth selected unaudited pro forma condensed combined consolidated statements of operations for the six months ended June 30, 2011 and the year ended December 31, 2010, as if the Plan of Arrangement had been completed on January 1, 2010, and the selected unaudited pro forma condensed combined consolidated balance sheet data as of June 30, 2011, as if the Plan of Arrangement had been completed on that date. The information presented below was derived from Atlantic Power's and CPILP's consolidated historical financial statements, and should be read in conjunction with these financial statements and the notes thereto, included elsewhere or incorporated by reference into this prospectus and the other unaudited pro forma financial data, including related notes, included elsewhere in this prospectus. CPILP's historical consolidated financial statements have been prepared in accordance with Canadian GAAP (or, in the case of the six months ended June 30, 2011, International Financial Reporting Standards) and include a discussion of the significant differences between Canadian GAAP and U.S. GAAP in Note 27 to the CPILP audited consolidated financial statements for the year ended December 31, 2010. For purposes of the unaudited pro forma condensed combined consolidated financial data, CPILP's balance sheet financial data has been translated from Canadian dollars into U.S. dollars using a C$/$ exchange rate of C$0.9643 to $1.00 and is presented in accordance with U.S. GAAP. CPILP's statement of operations financial data has been translated from Canadian dollars into U.S. dollars using an average C$/$ exchange rate of C$0.9766 to $1.00 and C$1.0295 to $1.00 for the six months ended June 30, 2011 and the year ended December 31, 2010, respectively, and is presented in accordance with U.S. GAAP.

The unaudited pro forma financial data is based on estimates and assumptions that are preliminary and does not purport to represent the financial position or results of operations that would actually have occurred had the Plan of Arrangement been completed as of the dates or at the beginning of the periods presented or what the combined company's results will be for any future date or any future period. See the sections entitled "Cautionary statements regarding forward-looking statements" and "Risk factors."

Unaudited Pro Forma Condensed Combined Consolidated Financial Information

(in thousands of U.S. dollars, except per share data and number of shares outstanding)	Six Months Ended June 30, 2011	Year Ended December 31, 2010
Combined consolidated statement of operations information		
Project revenues	$ 346,015	$ 669,985
Project income	60,937	91,687
Net income	19,817	11,135
Net income attributable to noncontrolling interest	6,952	13,597
Net income (loss) attributable to Atlantic Power Corporation/CPILP	12,865	(2,462)(1)
Earnings (loss) per share		
Basic	$ 0.11	$ (0.02)
Diluted	$ 0.11	$ (0.02)
Weighted average shares outstanding		
Basic	112,757	106,347
Diluted	113,184	106,347

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(in thousands of U.S. dollars)		As of June 30, 2011
Balance sheet information		
Cash and cash equivalents	$	145,409
Total assets		3,456,478
Long-term debt and convertible debentures		1,602,699
Total liabilities		2,096,958
Total Atlantic Power Corporation shareholders' equity		1,128,671
Noncontrolling interest		230,849
Total equity	$	1,359,520

(1) Net income (loss) attributable to Atlantic Power/CPILP on a pro forma basis reflects:

a. a significant increase in amortization expense as a result of the estimated increase in fair value associated with CPILP PPAs (see Note 5(e) in the notes to the unaudited pro forma condensed combined consolidated financial statements included elsewhere in this prospectus);

b. timing differences in Atlantic Power's deferred tax expense; and

c. timing differences in CPILP's deferred tax benefit.

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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, the PPA at our Badger Creek project expires in 2012 and represents 23 MWs of our net generating capacity. 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 11 contains details about 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 the equity method of accounting, are Progress Energy Florida, Inc. ("PEF"), Tampa Electric Company ("TECO"), and Atlantic City Electric ("ACE"), which purchase approximately 37%, 14% and 10%, 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 Chambers, the project has the right to sell a portion of the plant's output to our utility customer at spot market prices if it is economical to do so and the Chambers project shares in the profits from these sales. In addition, during periods of low spot electricity prices the customer takes less generation, which negatively affects the project's profitability. At Selkirk, approximately 23% of the capacity of the facility is not contracted and is sold at market prices or not sold at all if market prices do not support the profitable operation of that portion of the facility.

Our projects may not operate as planned.

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

In general, our power generation projects transmit electric power to the transmission grid for purchase under the PPAs through a single step up transformer. As a result, the transformer represents a single point of vulnerability and may exhibit no abnormal behavior in advance of a catastrophic failure that could cause a temporary shutdown of the facility until a replacement transformer can be found or manufactured.

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

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

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 payment formulas in the PPA. To the extent that fuel costs are not matched well to PPA energy payments, increases in fuel costs may adversely affect the profitability of the projects.

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 do not effectively pass through changes in natural gas prices.

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 could change in the future.

Generation from windpower projects may be less than anticipated.

We now own an interest in a windpower project, which is exposed to the risk of its wind resource having unfavorable characteristics, which could result in unfavorable financial impacts to its generation and revenues.

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 of 1935 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 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 require licenses, permits and approvals which can be in addition to any required environmental permits. No assurance can be provided that we will be able to obtain, comply with and renew, as required, all necessary licenses, permits and approvals for these facilities. If we cannot comply with and renew as required all applicable licenses, permits and approvals, our business, results of operations and financial condition could be adversely affected.

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

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

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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. Such a rate review has commenced in February 2011. The cost-of-service methodology currently applied by the FERC is well established and transparent; however, certain inputs in the FERC's determination of rates are subject to its discretion, including its response to protests from intervenors in such rate cases, which include return on equity and the recovery of certain extraordinary expenses. Unfavorable decisions on these matters could adversely affect Path 15 and our cash flow, financial position and results of operations, 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 non-governmental organization which has statutory responsibility, granted by the FERC, to regulate bulk power system users, owners and operators. NERC groups the users, owners, and operators of the bulk power system into 15 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 users, owners and operators of the bulk power system and the functional entity type(s) under which they are registered. All registered entities are responsible for complying with the applicable mandatory reliability standards and the FERC, or NERC or a regional reliability organization, with FERC's approval, may assess financial penalties or other enforcement actions against any responsible entity found to be in noncompliance. Violations may be discovered through self-certification, compliance audits, spot checking, self-reporting, compliance investigations by NERC (or a regional reliability organization) and the FERC, periodic data submittals, exception reporting, and complaints. The penalty that might be imposed for violating the requirements of the standards is a function of the Violation Risk Factor, a pre-violation assessment of the potential risk to the reliability of the bulk power system that a violation of a particular reliability standard requirement presents, and the Violation Security Level, a post-violation measurement of the degree to which a reliability standard requirement was violated. 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 and other enforcement actions 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, disposal, 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 presence and remediation of hazardous materials in soil and groundwater, both on and off site; the protection of natural resources; 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 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 by power plants. Environmental laws and regulations have generally become more stringent over time, and this trend may continue. In particular, the Environmental Protection Agency promulgated regulations under the federal Clean Air Interstate Rule ("CAIR") requiring additional reductions in nitrogen oxides, or "NOX," and sulphur dioxide, or "SO_2," emissions, beginning in 2009

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and 2010 respectively, and also promulgated regulations requiring reductions in mercury emissions from coal-fired electric generating units, beginning in 2010 with more substantial reductions expected 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 August 8, 2011, the Environmental Protection Agency promulgated the final Cross-State Air Pollution Rule (which will replace CAIR as of October 7, 2011) which requires 27 states and the District of Columbia to curb emissions of sulfur dioxide and nitrogen oxides from power plants through more aggressive state-by-state emissions limits for nitrogen oxides and sulfur dioxide. The first phase of compliance would begin on January 1, 2012 and the second (and more restrictive) phase would begin on January 1, 2014. Compliance with the new rule may have a material adverse impact on our business, operations or financial condition.

The Environmental Protection Agency proposed new mercury emissions standards for power plants on March 16, 2011 and is expected to have new standards in place by November 2011. Meeting these new standards at our coal-fired facility may have a material adverse impact on our business, operations or financial condition.

The Resource Conservation and Recovery Act has historically exempted fossil fuel combustion wastes from hazardous waste regulation. However, in June 2010 the Environmental Protection Agency proposed two alternative sets of regulations governing coal ash. One set of proposed regulations would designate coal ash as "special waste" and bring ash impoundments at coal-fired power plants under federal regulations governing hazardous solid waste under Subtitle C of the Resource Conservation and Recovery Act. Another set of proposed regulations would regulate coal ash as a non-hazardous solid waste. In March 2011, the Environmental Protection Agency announced that, due to the volume of public comments received on the two alternative sets of proposed coal ash regulations, it would not issue final regulations governing coal ash in 2011. If the Environmental Protection Agency ultimately decides to regulate coal ash as a hazardous waste, our coal-fired facility 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 improvements 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 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.

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Our projects are subject to regulation of CO_2 and other greenhouse gases.

Ongoing public concerns about emissions of CO_2 and other greenhouse gases have resulted in the enactment of, and proposals for, laws and regulations at the federal, state and regional levels, some of which do or could apply to some of our project operations. For example, the multi-state CO_2 cap-and-trade program known as the Regional Greenhouse Gas Initiative applies to our fossil fuel facilities in the Northeast region. The Regional Greenhouse Gas Initiative program went into effect on January 1, 2009. CO_2 allowances are auctioned quarterly, with a clearing price for the June 2011 auction of $1.89/ton, and can be traded within a secondary market at a similar price in 2011. The State of Florida has conducted stakeholder meetings and workshops as part of the process of developing greenhouse gas emissions regulations, the most recent of which was in 2009. In October 2010, the Florida DEP issued its "Comparative Study of Selected Offset Protocols for Greenhouse Gas Reduction and Reporting Programs." These regulatory efforts could result in stringent limits on CO_2 emissions in that state.

California, New Mexico, Washington and other states and Canadian Provinces 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 Solutions Act of 2006) the California Air Resources Board ("CARB") is required to adopt a greenhouse gas emissions cap on all major sources (not limited to the electric sector). In order to do so, it must adopt regulations for the mandatory reporting and verification of greenhouse gas emissions and to reduce state-wide emissions of greenhouse gases to 1990 levels by 2020. 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.

The legality of AB 32 has been challenged by several parties. On January 21, 2011, the San Francisco Superior Court issued a proposed decision that could significantly delay the implementation of AB 32. In *Association of Irritated Residents, et al. v. California Air Resources Board*, Case No. CPF-09-509562, the Court held that the CARB failed to comply with the California Environmental Quality Act. The Court found the CARB to have neglected to conduct a sufficient environmental impact review prior to adopting the AB 32 Scoping Plan. Specifically, CARB failed to adequately analyze all potential alternatives and prematurely adopted the Scoping Plan prior to fully responding to public comment. CARB has appealed that decision but, in the interim, has revised its alternatives analysis on which public comment was accepted until July 28, 2011.

SB 1368 required the California Energy Commission, in consultation with the California Public Utilities Commission (the "CPUC") and the CARB to 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 regulations have been finalized and establish a performance standard for greenhouse gas emissions from power plants 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.

In addition to the regional initiatives, legislation for the reduction of greenhouse gases has been introduced at the federal level and if passed, may eventually override the regional efforts with a national cap and trade program. 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 Environmental Protection Agency has taken several recent actions proposing possible regulation of greenhouse gas emissions.

The Environmental Protection Agency's actions include its finding of "endangerment" to public health and welfare from greenhouse gases, its issuance in September 2009 of the Final Mandatory Reporting of Greenhouse Gases Rule which requires large sources, including power plants, to monitor 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, effective January 2, 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.

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

All of our generating facilities met the March 31, 2011 requirement to submit 40 CFR Part 98 Mandatory Greenhouse Gas reporting for the emission of eligible site generated greenhouse gases in 2010.

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

The power generation industry is characterized by intense competition, and our projects encounter competition from utilities, industrial companies and other independent power producers, in particular with respect to uncontracted output. In recent years, there has been increasing competition among generators for power sales agreements, and this has contributed to a reduction in electricity prices in certain markets where supply has surpassed demand plus appropriate reserve margins. 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 a number of cases, our projects are not wholly-owned by us or we have contracted for their operations and maintenance, and in some cases we have limited control over the operation of the projects. Although we generally prefer to acquire projects where we have control, we may make acquisitions in non-control situations to the extent that we consider it advantageous to do so and consistent with regulatory requirements and restrictions, including the Investment Company Act of 1940. Third-party operators (such as Caithness, PPMS and Western) operate many of the projects. As such, we must rely on the technical and management expertise of these third-party operators, although typically we are represented on a management or operating committee if we do not own 100% of a project. To the extent that such third-party operators do not fulfill their obligations to manage the operations of the projects or are not effective in doing so, the amount of cash available to pay dividends may be adversely affected.

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

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

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

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 June 30, 2011, we had no borrowings outstanding under our revolving credit facility, $209.7 million of outstanding convertible debentures, and $285.1 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 non-recourse term loans or other financing arrangements in place with various lenders. These financing arrangements are typically secured by all of the project assets and contracts as well as our equity interests in the project. The terms of these financing arrangements generally impose many covenants and obligations on the part of the borrower. For example, some agreements contain requirements to maintain specified debt service coverage ratios before cash may be distributed from the relevant project to us, which is currently the case with a number of our projects. In many cases, a default by any party under key project agreements (such as a PPA or a fuel supply agreement) will also constitute a default under the project's term loan or other financing arrangement. Failure to comply with the terms of these term loans or other financing arrangements, or events of default thereunder, may prevent cash distributions by the 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 U.S. 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 U.S. 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.

Our Piedmont project is subject to construction risk.

The Piedmont project commenced construction in November 2010 and is expected to be completed in late 2012. In any construction project, there is a risk that circumstances occur which prevent the timely completion of a project, cause construction costs to exceed the level budgeted, or result in operating performance standards not being met.

In the event a power project does not achieve commercial operation by its expected date, the project may be subject to increased construction costs associated with the continuing accrual of interest on the project's construction loan, which customarily matures at the start of commercial operation and converts to a term loan. A delay in completion of construction may also impact a project under its PPA which may include penalty provisions for a delay in commercial operation date or in situations of extreme delay, termination of the PPA.

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

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

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.

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 if the projected short-term cash flow from the acquisition or investment are not adequate to service the capital raised to fund the acquisition or investment.

Future dividends are not guaranteed.

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

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

Our payments to shareholders 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 for our shareholders, including:

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

As of June 30, 2011, our consolidated long-term debt and our share of the debt of our unconsolidated affiliates represented approximately 53.4% of our total capitalization, comprised of debt and balance sheet equity.

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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.

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 that we pay are generally subject to Canadian withholding tax if paid to a shareholder that is not a resident of Canada. In connection with our conversion from an IPS structure to a traditional common share structure in 2009 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), 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.

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 note component of each IPS 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 primary 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 primary U.S. holding company will increase, which could materially affect our after-tax cash available for distribution. While we received advice from our U.S. tax counsel, based on certain representations by us and our primary 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 successfully challenge those positions and assert that the 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 interest payments on the subordinated notes would be subject to branch profits tax to the extent we had effectively connected earnings and profits, and interest payments on the Intercompany Note would be subject to U.S. withholding tax to the extent that our primary U.S. holding company had current or accumulated earnings and profits. The determination of whether the subordinated notes and the Intercompany Note are 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 the subordinated notes or the Intercompany Note were not debt, our U.S. federal income tax liability for the applicable open tax years would materially increase, which could materially affect our after-tax cash available for distribution. 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, the remainder would be treated as an equity distribution and potentially subject to withholding tax as described above. We have received advice from independent advisors that the interest rates on the subordinated notes and the Intercompany Note were, when issued, commercially reasonable under the circumstances, but the advice is not binding on the IRS.

Furthermore, pursuant to the U.S. "earnings stripping" limitations, our primary 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 the 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. Furthermore, if our primary 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 the 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.

Risks Related to the Plan of Arrangement

There can be no assurance that the Plan of Arrangement will be completed and this offering is not conditioned upon the completion of the Plan of Arrangement.

The Arrangement Agreement provides that we will acquire, directly or indirectly, all of the issued and outstanding CPILP units pursuant to a Plan of Arrangement under the *Canada Business Corporations Act*. Completion of the Plan of Arrangement is conditioned upon the receipt of certain governmental authorizations, consents, orders or other approvals, including but not limited to approval under the *Investment Canada Act*, the *Competition Act* (Canada), the *Hart-Scott-Rodino Antitrust Improvements Act of 1976, as amended* (United States) and the *United States Federal Power Act*. The Plan of Arrangement must also be approved by the Court of Queen's Bench of Alberta and both our

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shareholders and CPILP's unitholders. No assurance can be given that the required approvals will be obtained, and, even if such approvals are obtained, no assurance can be given as to the terms, conditions and timing of the approvals or that they will satisfy the terms of the Arrangement Agreement.

This offering is not conditioned on the completion of the Plan of Arrangement and there can be no assurance that the Plan of Arrangement will be completed. The common shares offered hereby will remain outstanding whether or not the Plan of Arrangement is completed.

If the financing for the transactions contemplated by the Arrangement Agreement becomes unavailable, the Plan of Arrangement may not be completed.

We intend to use the net proceeds from this offering to finance a portion of the cash purchase price necessary to complete the Plan of Arrangement. We plan to fund the remainder of the cash consideration payable by us under the Plan of Arrangement, including related fees and expenses, with the net proceeds from a senior unsecured notes offering and/or drawings under a $625 million senior secured credit facility, for which we have received the written commitment of a Canadian chartered bank and another financial institution. However, funding under this facility is subject to certain conditions, including, without limitation, that there shall not have occurred a material adverse effect with respect to Atlantic Power, CPILP, CPI Income Services Ltd. and CPI Investments Inc. taken as a whole. In the event that the lenders under the facility fail to provide funding for this or any other reason, we may not be able to complete the Plan of Arrangement and may be subject to a termination fee of C$35.0 million.

If the Arrangement Agreement is terminated, we may be required to pay a termination fee or make an expense reimbursement payment.

The Arrangement Agreement provides that we will pay a C$35.0 million termination fee to CPILP if CPILP terminates the Arrangement Agreement on account of certain actions or events, including the failure of our board of directors to maintain its favorable recommendation for the issuance of Atlantic Power common shares in connection with the Plan of Arrangement, failure of financing or a breach of our obligations under the Arrangement Agreement. If the Arrangement Agreement is terminated under circumstances where no termination fee is payable, we may still be required to make an expense reimbursement payment to CPILP, up to a maximum of C$8.0 million, in certain circumstances, including, but not limited to, if our shareholders do not approve issuance of our common shares in exchange for CPILP units pursuant to the Plan of Arrangement.

Failure to complete the Plan of Arrangement could negatively impact our share price and our future business and financial results.

If the Plan of Arrangement is not completed for any reason, our ongoing business may be adversely affected and we will be subject to a number of risks, including the following:

- we may be required, under certain circumstances, to pay a termination fee in the amount of C$35.0 million to CPILP or make a reimbursement of expenses payment to CPILP of up to C$8 million in connection with a termination of the Arrangement Agreement in certain circumstances;

- we will be required to pay certain other costs relating to the Arrangement Agreement and Plan of Agreement, whether or not completed, such as legal, accounting, financial advisor and printing fees; and

- matters relating to the Arrangement Agreement and Plan of Arrangement (including integration planning) require substantial commitments of time and resources by our management, whether or not the Plan of Arrangement is completed, which could otherwise have been devoted to conducting our business and pursuing other opportunities that may have been beneficial to us.

If the Plan of Arrangement is not completed, these risks may materialize and may adversely affect our business, operations, financial results and financial condition, as well as the trading price of our common shares.

We have not identified any specific use of the net proceeds of this offering in the event the Plan of Arrangement is not completed.

Consummation of the Plan of Arrangement is subject to a number of conditions and approvals, and, if the Plan of Arrangement is not completed for any reason, our board of directors and management will have broad discretion over the use of the net proceeds we receive following this offering and might not apply the net proceeds in ways that increase the trading price of our common shares. Since the primary purpose of this offering is to provide funds to pay a portion of the cash amount we are required to pay in connection with the Plan of Arrangement, we have not identified a specific use for the net proceeds in the event the Plan of Arrangement is not completed. Any funds received may be used by us for any corporate purpose, which may include pursuit of other business combinations, expansion of our operations, share repurchases or other uses. The failure of our management to use the net proceeds from this offering effectively could have an adverse effect on our business and may have an adverse effect on our earnings per share.

The failure to integrate successfully the businesses of Atlantic Power and CPILP in the expected timeframe would adversely affect the combined company's future results.

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

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

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

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Our growth plans upon completion of the Plan of Arrangement are dependent on future acquisitions and growth opportunities that may not be realized.

The ability to expand through acquisitions and growth opportunities is integral to our business strategy following completion of the Plan of Arrangement and requires that we identify and consummate suitable acquisition or investment opportunities that meet our investment criteria and are compatible with our growth strategy. We may not be successful in identifying and consummating acquisitions or investments that meet our investment criteria on satisfactory terms or at all. The failure to identify and consummate suitable acquisitions, to take advantage of other investment opportunities, or to integrate successfully any acquisitions without substantial expense, delay or other operational or financial problems, would impede our growth and negatively affect our results of operations and cash available for distribution to our shareholders.

We may be adversely affected by increased debt and debt service obligations.

We plan to fund a significant portion of the cash consideration payable by us under the Plan of Arrangement, including related fees and expenses, with the net proceeds from a senior unsecured notes offering and/or drawings under a $625 million senior secured credit facility, for which we have received the written commitment of a Canadian chartered bank and another financial institution. Such facility will be guaranteed by us and each of our existing and subsequently acquired or organized direct or indirect subsidiaries (excluding CPILP and each of its subsidiaries), and will contain covenants restricting certain actions by us and our subsidiaries (including CPILP and its subsidiaries), including financial, affirmative and negative covenants, which may include limitations on the ability to incur indebtedness, create liens and merge and consolidate with other companies, in each case, subject to exceptions and baskets that may be mutually agreed upon by us and the lender parties thereto, the exact terms of which will be negotiated before the effective time for the Plan of Arrangement.

Assuming completion of the Plan of Arrangement, we will have an increased amount of indebtedness. On a pro forma basis assuming the completion of this offering and that the Plan of Arrangement was consummated on , we would have had $ of indebtedness. We may also obtain additional long-term debt and working capital lines of credit to meet future financing needs, subject to certain restrictions under our existing indebtedness, which would further increase our total debt.

The potential significant negative consequences on our financial condition and results of operations that could result from our increased amount of debt include:

- limitations on our ability to obtain additional debt or equity financing;
- instances in which we are unable to meet the financial covenants contained in our debt agreements or to generate cash sufficient to make required debt payments, which circumstances would have the potential of accelerating the maturity of some or all of our outstanding indebtedness;
- the allocation of a material portion of our cash flow from operations to service our debt, thus reducing the amount of our cash flow available for other purposes, including funding operating costs and capital expenditures that could improve our competitive position, results of operations or share price;
- requiring us to sell debt or equity securities or to sell some of our core assets, possibly on unfavorable terms, to meet payment obligations;
- compromising our flexibility to plan for, or react to, competitive challenges in our business and the power industry;

- the possibility of us being put at a competitive disadvantage with our competitors that do not have as much debt as we have, and competitors that may be in a more favorable position to access additional capital resources in a timely manner; and

- limitations on our ability to execute business development activities to support our strategies.

A downgrade in Atlantic Power's or CPILP's credit ratings or any deterioration in their credit quality could negatively affect our ability to access capital and our ability to hedge and could trigger termination rights under certain contracts.

A downgrade in Atlantic Power's or CPILP's credit ratings or deterioration in their credit quality could adversely affect our ability to renew existing, or obtain access to new, credit facilities and could increase the cost of such facilities and trigger termination rights or enhanced disclosure requirements under certain contracts to which CPILP is a party. Any downgrade of CPILP's corporate credit rating could cause counterparties and financial derivative markets to require CPILP to post letters of credit or other collateral, make cash prepayments, obtain a guarantee agreement or provide other security, all of which would expose CPILP to additional costs.

Our results of operations may differ significantly from the unaudited pro forma condensed combined consolidated financial information included in this prospectus.

This prospectus includes unaudited pro forma condensed combined consolidated financial statements to illustrate the effects of the Plan of Arrangement on our historical financial position and operating results. The unaudited pro forma condensed combined consolidated statements of operations for the fiscal year ended December 31, 2010 and for the six months ended June 30, 2011 combine the historical consolidated statements of operations of Atlantic Power and CPILP, giving effect to the Plan of Arrangement, as if it had occurred on January 1, 2010. The unaudited pro forma condensed combined consolidated balance sheet as of June 30, 2011 combines the historical consolidated balance sheets of Atlantic Power and CPILP, giving effect to the Plan of Arrangement as if it had occurred on June 30, 2011. This unaudited pro forma financial information is presented for illustrative purposes only and does not necessarily indicate the results of operations or the combined financial position that would have resulted had the Plan of Arrangement been completed as of the dates or at the beginning of the periods presented, as applicable, nor is it indicative of the results of operations in future periods or the future financial position of the combined company.

We expect to incur significant expenses related to the integration of Atlantic Power and CPILP.

We have incurred significant expenses in connection with the Plan of Arrangement and expect to incur additional significant expenses in connection with the integration of Atlantic Power and CPILP. There are a large number of processes, policies, procedures, operations, technologies and systems that must be integrated. While we have assumed that a certain level of expenses will be incurred, there are many factors beyond our control that could affect the total amount or the timing of the integration expenses. Moreover, many of the expenses that will be incurred are, by their nature, difficult to estimate accurately. These integration expenses likely will result in our taking significant charges against earnings following the completion of the Plan of Arrangement, and the amount and timing of such charges are uncertain at present.

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

In connection with the accounting for the Plan of Arrangement, we expect to record a significant amount of goodwill and other intangible assets. Under U.S. GAAP, we must assess, at least annually and potentially more frequently, whether the value of goodwill and other indefinite-lived intangible assets has been impaired. Amortizing intangible assets will be assessed for impairment in the event of an impairment indicator. Any reduction or impairment of the value of goodwill or other

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intangible assets will result in a charge against earnings, which could materially adversely affect our results of operations and shareholders' equity in future periods.

We must continue to retain, motivate and recruit executives and other key employees, which may be difficult in light of the uncertainty regarding the Plan of Arrangement, and failure to do so could negatively affect us.

We must be successful at retaining, recruiting and motivating key employees following the completion of the Plan of Arrangement. Experienced employees in the power industry are in high demand and competition for their talents can be intense. Employees of both Atlantic Power and CPILP may experience uncertainty about their future role with the combined company until, or even after, strategies with regard to the combined company are announced or executed. These potential distractions of the Plan of Arrangement may adversely affect our ability to attract, motivate and retain executives and other key employees and keep them focused on applicable strategies and goals. A failure to retain and motivate executives and other key employees during the period prior to or after the completion of the Plan of Arrangement could have an adverse impact on our business.

There are factors that could cause the Plan of Arrangement not to be accretive and could cause dilution to our distributable cash flow per share, which may negatively affect the market price of our common shares.

We could encounter transaction and integration-related costs or other factors such as the failure to realize benefits anticipated in the Plan of Arrangement. All of these factors could cause dilution to our distributable cash flow per share or decrease or delay the expected accretive effect of the Plan of Arrangement and cause a decrease in the market price of our common shares. Accordingly, we may not be able to increase our dividends following completion of the Plan of Arrangement as currently planned.

CPI Preferred Equity Ltd. is subject to Canadian tax, as is Atlantic Power's income from CPILP.

As a Canadian corporation, we are generally subject to Canadian federal, provincial and other taxes. See "Risk factors Risks related to our structure We are subject to Canadian tax". Following completion of the Plan of Arrangement, we will be required to include in computing our taxable income any income earned by CPILP. In addition, CPI Preferred Equity Ltd., a subsidiary of CPILP, is also a Canadian corporation and is generally subject to Canadian federal, provincial and other taxes. CPI Preferred Equity Ltd. is, and following the completion of the Plan of Arrangement will continue to be, liable to pay material Canadian cash taxes.

Our incorporation of the CPILP structure following the Plan of Arrangement may be subject to additional U.S. federal income tax liability.

CPILP's U.S. structure has in place certain intercompany financing arrangements (the "CPILP Financing Arrangements"). While CPILP has received advice from its U.S. accountants, based on certain representations by its holding companies, that the payments on the CPILP Financing Arrangements should be deductible for U.S. federal income tax purposes, it is possible that the IRS could successfully challenge the deductibility of these payments. If the IRS were to succeed in characterizing these payments as non-deductible, the adverse consequences discussed above with respect to the Intercompany Loan could apply in connection with the CPILP Financing Arrangements. See "Risk factors Risks related to our structure Our prior and current structure may be subject to additional U.S. federal income tax liability." In addition, even if the payments are respected as interest, the deduction thereof could nevertheless be limited by the earnings stripping limitations, as discussed above with respect to our current structure. The earnings stripping limitations will also apply to other indebtedness of CPILP's U.S. group that is guaranteed by CPILP or Atlantic Power. Finally, the applicability of recent changes to the U.S.-Canada Income Tax Treaty to the structure associated with certain of the CPILP Financing Arrangements may result in distributions from CPILP's U.S. group to its Canadian parent being subject to a 30% rate of withholding tax instead of the 5% rate that would otherwise have applied.

Risks Related to Our 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 purchase 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;

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.

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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 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, 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, 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.

CAUTIONARY STATEMENTS REGARDING FORWARD-LOOKING STATEMENTS

This prospectus and the documents incorporated by reference herein contain forward-looking statements within the meaning of the *Private Securities Litigation Reform Act of 1995* with respect to the financial condition, results of operations, business strategies, operating efficiencies, synergies, revenue enhancements, competitive positions, plans and objectives of management and growth opportunities of Atlantic Power and CPILP, and with respect to the Plan of Arrangement and the markets for CPILP units and Atlantic Power common shares and other matters. Statements in this prospectus and the documents incorporated by reference herein that are not historical facts are hereby identified as forward-looking statements for the purpose of the safe harbor provided by Section 27A of the Securities Act and Section 21E of the Exchange Act and forward-looking information within the meaning defined under applicable Canadian securities legislation (collectively, "forward-looking statements").

These forward-looking statements relate to, among other things, the expected benefits of the Plan of Arrangement, such as accretion, the ability to pay increased dividends, enhanced cash flow, growth potential, liquidity and access to capital, market profile and financial strength, the position of the combined company and the expected timing of the completion of the Plan of Arrangement, if completed.

Forward-looking statements can generally be identified by the use of words such as "should," "intend," "may," "expect," "believe," "anticipate," "estimate," "continue," "plan," "project," "will," "could," "would," "target," "potential" and other similar expressions. In addition, any statements that refer to expectations, projections or other characterizations of future events or circumstances are forward-looking statements. Although we believe that the expectations reflected in such forward-looking statements are reasonable, such statements involve risks and uncertainties, and undue reliance should not be placed on such statements. Certain material factors or assumptions are applied in making forward-looking statements, including, but not limited to, factors and assumptions regarding the items outlined above. Actual results may differ materially from those expressed or implied in such statements. Important factors that could cause actual results to differ materially from these expectations include, among other things:

- the failure to receive, on a timely basis or otherwise, the required approvals by Atlantic Power shareholders, CPILP unitholders and government or regulatory agencies (including the terms of such approvals);
- the risk that a condition to closing of the Plan of Arrangement may not be satisfied;
- the possibility that the anticipated benefits and synergies from the Plan of Arrangement cannot be fully realized or may take longer to realize than expected;
- the possibility that costs or difficulties related to the integration of Atlantic Power and CPILP operations will be greater than expected;
- the ability of the combined company to retain and hire key personnel and maintain relationships with customers, suppliers or other business partners;
- the impact of legislative, regulatory, competitive and technological changes;
- the risk that the credit ratings of the combined company may be different from what the companies expect;
- the amount of distributions expected to be received from our projects and our estimated net cash tax refunds;

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- the expected use of proceeds from this offering and any private offering of senior unsecured notes; and

- other risk factors relating to us and the power industry, as detailed from time to time in our filings with the SEC and the Canadian Securities Administrators (the "CSA").

Additional information about these factors and about the material factors or assumptions underlying such forward-looking statements may be found in this prospectus under the section entitled "Risk factors," beginning on page 19.

You are cautioned that any forward-looking statement speaks only as of the date of this prospectus or, if such statement is included in a document incorporated by reference into this prospectus, as of the date of such other document. We undertake no obligation to update or revise any forward-looking statement, whether as a result of new information, future events or otherwise, except as may be required by applicable law.

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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, 2011, the noon buying rate was $1.00 = C$0.9913.

	Six Months Ended June 30,		Twelve Months Ended December 31,				
	2011	2010	2010	2009	2008	2007	2006
High	C$ 1.0022	C$ 1.0778	C$ 1.0778	C$ 1.3000	C$ 1.2969	C$ 1.1853	C$ 1.1726
Low	C$ 0.9486	C$ 0.9961	C$ 0.9946	C$ 1.0292	C$ 0.9719	C$ 0.9170	C$ 1.0990
Average	C$ 0.9769	C$ 1.0338	C$ 1.0299	C$ 1.1420	C$ 1.0660	C$ 1.0748	C$ 1.1341
Period End	C$ 0.9643	C$ 1.0606	C$ 0.9946	C$ 1.0466	C$ 1.2246	C$ 1.0120	C$ 1.1653

Source: Bank of Canada

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USE OF PROCEEDS

We expect to receive net proceeds from this offering of approximately $ million after deducting the underwriting discount and our estimated expenses (or approximately $ million if the underwriters exercise their over-allotment option to purchase additional shares in full). We intend to use the net proceeds from this offering to:

(i) fund a portion of the cash consideration payable by us under the Plan of Arrangement; and

(ii) to the extent that any proceeds remain thereafter, or the Plan of Arrangement is not completed, to fund additional growth opportunities and for general corporate purposes.

This offering is not conditioned on the completion of the Plan of Arrangement and there can be no assurance that the Plan of Arrangement will be completed. The shares offered hereby will remain outstanding whether or not the Plan of Arrangement is completed.

We intend to fund the remainder of the cash consideration payable by us under the Plan of Arrangement, including related fees and expenses, with the net proceeds from a senior unsecured notes offering and/or borrowings under a $625 million senior secured credit facility, for which we have received the written commitment of a Canadian chartered bank and another financial institution. This offering is not conditioned upon the successful completion of a private offering of senior unsecured notes and any private offering of senior unsecured notes will not be conditioned upon the successful completion of this offering.

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DIVIDENDS AND 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 C$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.

The transactions contemplated by the Plan of Arrangement are expected to be immediately accretive to cash available for distribution following the effective date of the Plan of Arrangement. As a result, our management intends to recommend to our board of directors to increase our dividend by 5% from C$1.094 per share to C$1.15 per share on an annual basis following the effective date of the Plan of Arrangement. Upon completion of the Plan of Arrangement, our dividend will continue to be paid monthly. Future dividends are paid at the discretion of our board of directors subject to, among other things, 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.

Dividends declared per common share (or distributions per IPS) for each of the monthly periods shown below were as follows (C$):

Month	2011	2010	2009
		Amount	
January	$ 0.0912	$ 0.0912	$ 0.0912
February	0.0912	0.0912	0.0912
March	0.0912	0.0912	0.0912
April	0.0912	0.0912	0.0912
May	0.0912	0.0912	0.0912
June	0.0912	0.0912	0.0912
July	0.0912	0.0912	0.0912
August	0.0912	0.0912	0.0912
September		0.0912	0.0912
October		0.0912	0.0912
November		0.0912	0.0912
December		0.0912	0.0912

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MARKET PRICE OF THE COMMON SHARES

The IPSs were listed and posted for trading on the TSX under the symbol "ATP.UN" from the time of 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:

	High (C$)	Low (C$)
2009		
First Quarter	$ 9.28	$ 6.34
Second Quarter	9.45	7.71
Third Quarter	9.49	8.55
Fourth Quarter	11.90	9.08
2010		
First Quarter	13.85	11.50
Second Quarter	12.90	11.20
Third Quarter	14.47	12.11
Fourth Quarter	15.18	13.31
2011		
First Quarter	15.50	14.41
Second Quarter	15.72	13.82
Third Quarter (until September 14, 2011)	15.46	12.92

Our shares began trading on the NYSE under the symbol "AT" on July 23, 2010. The following table sets forth the price ranges of our outstanding common shares, as reported by the NYSE from the date on which our common shares were listed through December 31, 2010:

	High ($)	Low ($)
2010		
Third Quarter (beginning July 23, 2010)	$ 14.00	$ 12.10
Fourth Quarter	14.98	13.26
2011		
First Quarter	15.75	14.72
Second Quarter	16.18	14.33
Third Quarter (until September 14, 2011)	16.34	13.12

On September 14, 2011, there were 68,984,192 of our common shares issued and outstanding, and the number of holders of our common shares was approximately 53,998.

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CAPITALIZATION

The following table shows our capitalization as of June 30, 2011:

- on an actual basis;

- on an as adjusted basis to give effect to the sale of our common shares in this offering, at an assumed offering price of $14.71 per share, the last reported sale price of our common shares on the New York Stock Exchange September 14, 2011, after deducting underwriting discounts and estimated transaction expenses payable by us; and

- on an as further adjusted basis to give effect to:

  - the issue of approximately 31.5 million common shares we expect to issue in exchange for CPILP units in connection with the Plan of Arrangement;

  - the incurrence of additional debt (in the form of one or more private issuances of senior notes, borrowings under our available credit facilities or a combination thereof) in the amount of $425 million; and

- application of the net proceeds from this offering, any senior notes offerings and/or any borrowings under our credit facilities to pay the cash portion of the amounts payable by us pursuant to the Plan of Arrangement, including related fees, costs and expenses, and completion of the Plan of Arrangement as described elsewhere in this prospectus.

This offering is not conditioned on the completion of the Plan of Arrangement and there can be no assurance that the Plan of Arrangement will be completed. The shares offered hereby will remain outstanding whether or not the Plan of Arrangement is completed.

You should read this table in conjunction with the sections entitled "Use of proceeds" and "Unaudited pro forma condensed combined consolidated financial statements" included elsewhere in

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this prospectus, in addition to our consolidated financial statements and related notes incorporated by reference herein.

	As of June 30, 2011		
	Actual	As adjusted (unaudited)	As further adjusted
	(in thousands)		
Cash and cash equivalents:	$ 46,551	$ 236,831	$ 650,019
Debt:			
Convertible debentures due 2014	$ 48,628	$ 48,628	$ 48,628
Convertible debentures due 2017	77,612	77,612	77,612
Convertible debentures due 2017	83,463	83,463	83,463
Senior unsecured notes(1)			425,000
Current portion of project-level debt	21,962	21,962	21,962
Project-level debt	263,111	263,111	263,111
Total debt:	494,776	494,776	919,776
Shareholders' equity:			
Common shares, no par value per share, unlimited authorized shares, 68,639,654 shares issued and outstanding, actual; shares issued and outstanding, as adjusted(2)	644,011		
Accumulated other comprehensive loss	24	24	24
Retained deficit	(215,782)	(215,782)	(215,782)
Total shareholder's equity	428,243		
Total capitalization	$ 969,570	$	$

(1) Assumes completion of an offering of $425 million of senior unsecured notes. If we do not complete an offering of senior unsecured notes and the Plan of Arrangement is completed, we intend to fund the remainder of the cash consideration payable by us from borrowing under a $625 million senior secured credit facility. See "Use of proceeds."

(2) Excludes (i) 13,643,645 shares issuable upon conversion, redemption, purchase for cancellation or maturity of our outstanding convertible debentures, and (ii) 409,295 unvested notional units granted under the terms of our Long Term Incentive Plan.

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SELECTED HISTORICAL CONSOLIDATED FINANCIAL INFORMATION FOR ATLANTIC POWER

The following table presents summary consolidated financial information for Atlantic Power. The annual historical information as of December 31, 2010 and 2009 and for the years ended, December 31, 2010, 2009 and 2008 has been derived from the audited consolidated financial statements appearing in Atlantic Power's Annual Report on Form 10-K for the year ended December 31, 2010, incorporated by reference into this prospectus. The annual historical information as of December 31, 2008, 2007 and 2006 and for the years ended December 31, 2007 and 2006 has been derived from historical financial statements not incorporated by reference into this prospectus. The historical information as of, and for the six-month periods ended June 30, 2011 and 2010 has been derived from the unaudited consolidated financial statements appearing in Atlantic Power's Quarterly Report on Form 10-Q for the quarter ended June 30, 2011, incorporated by reference into this prospectus. Data for all periods have been prepared under U.S. GAAP. You should read the following selected consolidated financial data together with Atlantic Power's consolidated financial statements and the notes thereto and the discussion under "Management's Discussion and Analysis of Financial Condition and Results of Operations" included as part of Atlantic Power's Annual Report on Form 10-K for the year ended December 31, 2010 and Quarterly Report on Form 10-Q for the quarter ended June 30, 2011, each of which is incorporated by reference into this prospectus. See "Where you can find more information" beginning on page 85 of this prospectus.

(in thousands of US dollars, except per share/subordinated note data and as otherwise stated)	Year Ended December 31,					Six Months Ended June 30,	
	2010	**2009**	**2008**	**2007**	**2006[(a)]**	**2011[(a)]**	**2010[(a)]**
Project revenue	$ 195,256	$ 179,517	$ 173,812	$ 113,257	$ 69,374	$ 106,923	$ 95,125
Project income	41,879	48,415	41,006	70,118	57,247	27,900	19,405
Net (loss) income attributable to Atlantic Power Corporation	(3,752)	(38,486)	48,101	(30,596)	(2,408)	19,322	(4,618)
Basic earnings (loss) per share	$ (0.06)	$ (0.63)	$ 0.78	$ (0.50)	$ (0.05)	$ 0.28	$ (0.08)
Basic earnings (loss) per share, C$[(b)]	$ (0.06)	$ (0.72)	$ 0.84	$ (0.53)	$ (0.06)	$ 0.28	$ (0.08)
Diluted earnings (loss) per share[(c)]	$ (0.06)	$ (0.63)	$ 0.73	$ (0.50)	$ (0.05)	$ 0.28	$ (0.08)
Diluted earnings (loss) per share, C$[(b)(c)]	$ (0.06)	$ (0.72)	$ 0.78	$ (0.53)	$ (0.06)	$ 0.28	$ (0.08)
Distribution per subordinated note[(d)]	$	$ 0.51	$ 0.60	$ 0.59	$ 0.57	$	$
Dividend declared per common share	$ 1.06	$ 0.46	$ 0.40	$ 0.40	$ 0.37	$ 0.57	$ 0.52
Total assets	$ 1,013,012	$ 869,576	$ 907,995	$ 880,751	$ 965,121	$ 1,008,980	$ 862,525
Total long-term liabilities	$ 518,273	$ 402,212	$ 654,499	$ 715,923	$ 613,423	$ 523,351	$ 407,413

(a) Unaudited.

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

(c) Diluted earnings (loss) per share is computed including dilutive potential shares, which include those issuable upon conversion of convertible debentures and under our long term incentive plan. Because we reported a loss during the years ended December 31, 2010, 2009, 2007 and 2006, and for the six-month period ended June 30, 2010, 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 incorporated by reference into this prospectus for information relating to the number of shares used in calculating basic and diluted earnings per share for the periods presented.

(d) At the time of our initial public offering, our publicly traded security was an income participating security, or an "IPS," each of which was comprised of one common share and C$5.767 principal amount of 11% subordinated notes due 2016. On November 27, 2009, we converted from the IPS structure to a traditional common share structure. In connection with the conversion, each IPS was exchanged for one new common share.

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SELECTED HISTORICAL CONSOLIDATED FINANCIAL INFORMATION OF CPILP

The following table presents selected consolidated financial information for CPILP. The selected historical financial data as of, and for the years ended, December 31, 2010, 2009 and 2008 has been derived from CPILP's audited consolidated financial statements for those periods prepared under Canadian generally accepted accounting principles and appearing elsewhere in this prospectus. Data as of, and for the years ended, December 31, 2010 and 2009 has be reconciled to U.S. generally accepted accounting principles as noted below. The selected historical financial data as of, and for the years ended, December 31, 2007 and 2006 has been derived from the audited consolidated financial statements of CPILP prepared under Canadian generally accepted accounting principles not appearing in this prospectus. The selected historical financial data as of, and for the six-month periods ended June 30, 2011 and 2010 has been derived from CPILP's unaudited consolidated financial statements for those periods appearing elsewhere in this prospectus.

Data for all periods presented below is reported in Canadian dollars. You should read the following selected consolidated financial data together with CPILP's consolidated financial statements and the notes thereto included elsewhere in this prospectus.

(in thousands of Canadian dollars, except per unit data)	Year Ended December 31,					Six Months Ended June 30,	
	2010	2009	2008	2007	2006	2011[(a)(b)]	2010[(a)(b)]
Revenue	$ 532,377	$ 586,491	$ 499,267	$ 549,872	$ 326,900	$ 261,524	$ 241,453
Depreciation, amortization and accretion	$ 98,227	$ 93,249	$ 88,313	$ 85,553	$ 65,200	$ 45,461	$ 47,826
Financial charges and other, net	$ 40,179	$ 46,462	$ 94,836	$ 8,574	$ 42,200	$ 21,457	$ 21,384
Net income before tax and preferred share dividends	$ 35,224	$ 56,812	$ (91,918)	$ 108,953	$ 67,400	$ 18,741	$ 4,705
Net income (loss) attributable to equity holders of CPILP	$ 30,500	$ 57,553	$ (67,893)	$ 30,816	$ 62,121	$ 10,529	$ 8,410
Basic and diluted net income (loss) per unit, C$	$ 0.55	$ 1.07	$ (1.26)	$ 0.59	$ 1.28	$ 0.19	$ 0.15
Distributions declared per unit, C$	$ 1.76	$ 1.95	$ 2.52	$ 2.52	$ 2.52	$ 0.88	$ 0.88
Total assets	$ 1,583,910	$ 1,668,057	$ 1,809,225	$ 1,852,573	$ 1,883,400	$ 1,471,772	$ 1,667,775
Total long-term liabilities	$ 874,190	$ 853,314	$ 935,248	$ 730,940	$ 757,800	$ 821,382	$ 900,995
Operating margin[(c)]	$ 187,567	$ 211,680	$ 111,446	$ 216,188	$ 185,900	$ 99,675	$ 77,753

(a) Unaudited.

(b) Results have been prepared using International Financial Reporting Standards.

(c) Operating margin is a non-GAAP financial measure. CPILP uses operating margin as a performance measure. Operating margin is not a defined financial measures according to Canadian generally accepted accounting principles or International Financial Reporting Standards and does not have a standardized meaning prescribed by Canadian generally accepted accounting principles or International Financial Reporting Standards. Therefore, operating margin may not be comparable to similar measures presented by other enterprises.

Under U.S. GAAP, the following differences are noted for the years indicated below:

(in thousands of Canadian dollars, except per unit data)	Years Ended December 31,	
	2010	2009
Revenue	$ 532,377	$ 586,491
Depreciation, amortization and accretion	$ 98,277	$ 93,249
Financial charges and other, net	$ 40,179	$ 46,462
Net income before tax and preferred share dividends	$ 39,179	$ 54,753
Net income (loss) attributable to equity holders of CPILP	$ 34,455	$ 55,529
Basic and diluted net income (loss) per unit, C$	$ 0.63	$ 1.03
Distributions declared per unit, C$	$ 1.76	$ 1.95

Total assets	$ 1,588,352	$ 1,673,059
Total long-term liabilities	$ 878,632	$ 858,317
Operating margin	$ 191,530	$ 209,621

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UNAUDITED PRO FORMA CONDENSED COMBINED CONSOLIDATED FINANCIAL STATEMENTS

The unaudited pro forma condensed combined consolidated statements of operations and balance sheet (which we refer to as the pro forma financial statements) combine the historical consolidated financial statements of Atlantic Power and CPILP to illustrate the effect of the Plan of Arrangement. The pro forma financial statements were based on and should be read in conjunction with the:

- accompanying notes to the Unaudited Pro Forma Condensed Combined Consolidated Financial Statements;

- consolidated financial statements of Atlantic Power for the year ended December 31, 2010 and for the six months ended June 30, 2011 and the notes relating thereto, incorporated herein by reference; and

- consolidated financial statements of CPILP for the year ended December 31, 2010 and for the six months ended June 30, 2011 and the notes relating thereto, elsewhere in this prospectus.

The historical consolidated financial statements have been adjusted in the pro forma financial statements to give effect to pro forma events that are (1) directly attributable to the Plan of Arrangement, (2) factually supportable and (3) with respect to the unaudited pro forma condensed combined consolidated statements of operations (which we refer to as the pro forma statements of operations), expected to have a continuing impact on the combined results. The pro forma statements of operations for the year ended December 31, 2010 and for the six months ended June 30, 2011, give effect to the Plan of Arrangement as if it occurred on January 1, 2010. The Unaudited Pro Forma Condensed Combined Consolidated Balance Sheet (which we refer to as the pro forma balance sheet) as of June 30, 2011, gives effect to the Plan of Arrangement as if it occurred on June 30, 2011.

As described in the accompanying notes, the pro forma financial statements have been prepared using the acquisition method of accounting under existing United States generally accepted accounting principles, or GAAP, and the regulations of the SEC. Atlantic Power has been treated as the acquirer in the transaction for accounting purposes. The acquisition accounting is dependent upon certain valuations and other studies that have yet to commence or progress to a stage where there is sufficient information for a definitive measurement. Accordingly, the pro forma financial statements are preliminary and have been made solely for the purpose of providing unaudited pro forma condensed combined consolidated financial information. Differences between these preliminary estimates and the final acquisition accounting will occur and these differences could have a material impact on the accompanying pro forma financial statements and the combined company's future results of operations and financial position.

The pro forma financial statements have been presented for informational purposes only and are not necessarily indicative of what the combined company's results of operations and financial position would have been had the transaction been completed on the dates indicated. In addition, the pro forma financial statements do not purport to project the future results of operations or financial position of the combined company.

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ATLANTIC POWER CORPORATION AND CAPITAL POWER INCOME L.P.

UNAUDITED PRO FORMA CONDENSED COMBINED

CONSOLIDATED STATEMENT OF OPERATIONS

For the Six Months Ended June 30, 2011

(in thousands, except per share data)

	Atlantic Power Historical (unaudited)[(a)]	CPILP Historical (unaudited)[(a)(1)]	Pro Forma Adjustments[(b)]	Pro Forma Combined
Project revenue:	$ 106,923	$ 257,148	$ (18,056)[(d)]	$ 346,015
Project expenses:				
Fuel	31,384	145,152	(10,308)[(d)]	166,228
Operations and maintenance	18,873	16,997	(10,416)[(d)]	25,454
Depreciation and amortization	21,803	45,461	19,485(c),(d),(e)	86,749
	72,060	207,610	(1,239)	278,431
Project other income (expense):				
Change in fair value of derivative instruments	(1,013)	299	17	(697)
Equity in earnings of unconsolidated affiliates	3,273			3,273
Interest expense, net	(9,190)			(9,190)
Other expense, net	(33)			(33)
	(6,963)	299	17	(6,647)
Project income	27,900	49,837	(16,800)	60,937
Administrative and other expenses (income):				
Administration	8,725	14,016	(350)[(d)]	22,391
Interest expense, net	7,478	21,430	13,397(c),(f)	42,305
Foreign exchange gain	(1,193)	(4,351)	(91)	(5,635)
	15,010	31,095	12,956	59,061
Income (loss) from operations before income taxes	12,890	18,742	(29,756)	1,876
Income tax expense (benefit)	(6,161)	1,159	(12,939)[(e),(i)]	(17,941)
Net income (loss)	19,051	17,583	16,817	19,817
Net (loss) income attributable to noncontrolling interest	(271)	7,054	169	6,952
Net income (loss) attributable to Atlantic Power Corporation/CPILP	$ 19,322	$ 10,529	$ (16,986)	$ 12,865
Net income (loss) per share attributable to Atlantic Power Corporation shareholders / CPILP unitholders:				
Basic	$ 0.28	$ 0.19	$ (0.36)	$ 0.11
Diluted	$ 0.28	$ 0.19	$ (0.36)	$ 0.11

(1) The CPILP historical results are in recorded in Canadian dollars and are in accordance with IFRS. See Note 5(b) and (c) for an explanation of the conversion to U.S. dollars and U.S. GAAP.

See accompanying Notes to the Unaudited Pro Forma Condensed Combined Consolidated Financial Statements, which are an integral part of these statements.

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ATLANTIC POWER CORPORATION AND CAPITAL POWER INCOME L.P.

UNAUDITED PRO FORMA CONDENSED COMBINED

CONSOLIDATED STATEMENT OF OPERATIONS

For the Year Ended December 31, 2010

(in thousands, except per share data)

	Atlantic Power Historical (unaudited)[(a)]	CPILP Historical (unaudited)[(a)(1)]	Pro Forma Adjustments[(b)]	Pro Forma Combined
Project revenue:	$ 195,256	$ 524,569	$ (49,840)(d)	$ 669,985
Project expenses:				
Fuel	65,553	219,218	(27,387)(c),(d)	257,384
Operations and maintenance	31,237	114,164	(18,908)(d)	126,493
Depreciation and amortization	40,387	98,277	28,604(d),(e)	167,268
	137,177	431,659	(17,691)	551,145
Project other income (expense):				
Change in fair value of derivative instruments	(14,047)	(11,421)	468	(25,000)
Equity in earnings of unconsolidated affiliates	15,288			15,288
Interest expense, net	(17,660)			(17,660)
Other expense, net	219			219
	(16,200)	(11,421)	468	(27,153)
Project income	41,879	81,489	(31,681)	91,687
Administrative and other expenses (income):				
Administration	16,149	13,945	(2,292)(d)	27,802
Interest expense, net	11,701	40,129	26,771(d),(f)	78,601
Foreign exchange gain	(1,014)	(7,808)	234(c)	(8,588)
Other (income)	(26)		(1,121)(d)	(1,147)
	26,810	46,266	23,592	96,668
Income (loss) from operations before income taxes	15,069	35,223	(55,273)	(4,981)
Income tax expense (benefit)	18,924	(9,384)	(25,656)(e),(i)	(16,116)
Net income (loss)	(3,855)	44,607	(29,617)	11,135
Net (loss) income attributable to noncontrolling interest	(103)	14,107	(407)	13,597
Net income (loss) attributable to Atlantic Power Corporation/CPILP	$ (3,752)	$ 30,500	$ (29,210)	$ (2,462)
Net income (loss) per share attributable to Atlantic Power Corporation shareholders/CPILP unitholders:				
Basic	$ (0.06)	$ 0.55	$ (0.51)	$ (0.02)
Diluted	$ (0.06)	$ 0.55	$ (0.51)	$ (0.02)

(1) The CPILP historical results are recorded in Canadian dollars and are in accordance with Canadian GAAP. See Note 5(b) and (c) for an explanation of the conversion to U.S. dollars and U.S. GAAP.

See accompanying Notes to the Unaudited Pro Forma Condensed Combined Consolidated Financial Statements, which are an integral part of these statements.

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ATLANTIC POWER CORPORATION AND CAPITAL POWER INCOME L.P.

UNAUDITED PRO FORMA CONDENSED COMBINED

CONSOLIDATED BALANCE SHEET

As of June 30, 2011

(in thousands)

	Atlantic Power Historical (unaudited)[(a)]	CPILP Historical (unaudited)[(a)(1)]	Pro Forma Adjustments[(b)]	Pro Forma Combined
Assets				
Current assets:				
Cash and cash equivalents	$ 46,551	$ 12,826	$ 86,032(d),(f)	$ 145,409
Restricted cash	21,034			21,034
Accounts receivable	20,028	48,749	1,805	70,582
Note receivable related party	7,326			7,326
Current portion of derivative instruments asset	9,297	13,021	482	22,800
Prepayments, supplies, and other	8,451	18,143	672	27,266
Asset held for sale		130,613	(130,613)[(d)]	
Refundable income taxes	1,611			1,611
Total current assets	114,298	223,352	(41,622)	296,028
Property, plant, and equipment, net	308,051	835,881	204,252(c),(e)	1,348,184
Transmission system rights	184,208			184,208
Equity investments in unconsolidated affiliates	276,962	31,344	1,160	309,466
Other intangible assets, net	77,425	270,441	363,179(c),(e)	711,045
Goodwill	12,453	19,689	421,639(c),(h)	453,781
Derivative instruments asset	18,865	32,710	1,211	52,786
Deferred income taxes		20,337	19,459(c),(i)	39,796
Other assets	16,718	38,018	6,448(c),(f)	61,184
Total assets	$ 1,008,980	$ 1,471,772	$ 975,726	$ 3,456,478
Liabilities				
Current Liabilities:				
Accounts payable and accrued liabilities	$ 16,333	$ 59,423	$ 27,557(c),(g)	$ 103,313
Liabilities held for sale		15,367	(15,367)[(d)]	
Current portion of long-term debt	21,962			21,962
Current portion of derivative instruments liability	7,410	23,138	857	31,405
Interest payable on convertible debentures	1,948			1,948
Dividends payable	6,490			6,490
Other current liabilities	7			7
Total current liabilities	54,150	97,928	13,047	165,125
Long-term debt	263,111	675,465	454,420(c),(f)	1,392,996
Convertible debentures	209,703			209,703
Derivative instruments liability	24,822	79,686	2,950	107,458
Deferred income taxes	23,594	17,200	150,812(c),(i)	191,606
Other non-current liabilities	2,121	49,031	(21,082)(c)	30,070
Equity				
Common shares	644,001	332,301	345,079(f),(j)	1,321,381
Accumulated other comprehensive loss	24			24
Retained deficit	(215,782)		23,048(g),(i)	(192,734)
Total shareholders' equity	428,243	332,301	368,127	1,128,671
Noncontrolling interest	3,236	220,161	7,452(c)	230,849

Total equity	431,479	552,462	375,579	1,359,520
Total liabilities and equity	$ 1,008,980	$ 1,471,772	$ 975,726	$ 3,456,478

(1) The CPILP historical results are in recorded in Canadian dollars and are in accordance with IFRS. See Note 5(b) and (c) for an explanation of the conversion to U.S. dollars and U.S. GAAP.

See accompanying Notes to the Unaudited Pro Forma Condensed Combined Consolidated Financial Statements, which are an integral part of these statements.

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ATLANTIC POWER CORPORATION AND CAPITAL POWER INCOME L.P.

NOTES TO THE UNAUDITED PRO FORMA CONDENSED

COMBINED CONSOLIDATED FINANCIAL STATEMENTS

Note 1. Description of the Transaction

On June 20, 2011, Atlantic Power, CPILP, CPILP's general partner and CPI Investments Inc. entered into the Arrangement Agreement, which provides that Atlantic Power will acquire, directly or indirectly, all of the issued and outstanding CPILP units pursuant to a court-approved statutory Plan of Arrangement under the CBCA. Under the terms of the Plan of Arrangement, CPILP unitholders will be permitted to exchange each of their CPILP units for, at their election, C$19.40 in cash or 1.3 Atlantic Power common shares. All cash elections will be subject to proration if total cash elections exceed approximately C$506.5 million and all share elections will be subject to proration if total share elections exceed approximately 31.5 million Atlantic Power common shares.

Pursuant to the Plan of Arrangement, CPILP will sell its Roxboro and Southport facilities located in North Carolina to an affiliate of Capital Power Corporation, for approximately C$121.4 million. Additionally, in connection with the Plan of Arrangement, the management agreements between certain subsidiaries of Capital Power Corporation and CPILP and certain subsidiaries of CPILP will be terminated (or assigned to Atlantic Power) in consideration of a payment of C$10 million. Atlantic Power will assume the management of CPILP and enter into a transitional services agreement with Capital Power Corporation for a term of up to 12 months following closing, which will facilitate the integration of CPILP into Atlantic Power.

Note 2. Basis of Pro Forma Presentation

The pro forma financial statements were derived from historical consolidated financial statements of Atlantic Power and CPILP. Certain reclassifications have been made to the historical financial statements of CPILP to conform with Atlantic Power's presentation. This resulted in income statement adjustments to operating revenues, operating expenses, other income and deductions and balance sheet adjustments to current assets, long term assets, current liabilities and other long term liabilities.

The historical consolidated financial statements have been adjusted in the pro forma financial statements to give effect to pro forma events that are (1) directly attributable to the transaction, (2) factually supportable, and (3) with respect to the pro forma statement of operations, expected to have a continuing impact on the combined results. The following matters have not been reflected in the pro forma financial statements as they do not meet the aforementioned criteria.

- Cost savings (or associated costs to achieve such savings) from operating efficiencies, synergies or other restructuring that could result from the transaction with CPILP. The timing and effect of actions associated with integration are currently uncertain.

- A fair value adjustment for CPILP's pension and other postretirement benefit obligations. Atlantic Power management believes the actuarial assumptions and methods used to measure CPILP's obligations and costs for financial accounting purposes for 2010 and 2011 are appropriate in the circumstances. The final fair value determination of the pension and postretirement benefit obligations may differ materially, largely due to potential changes in discount rates, return on plan assets up to the date of completion of the transaction and the conforming of certain Atlantic Power and CPILP assumptions surrounding the determination of these obligations.

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ATLANTIC POWER CORPORATION AND CAPITAL POWER INCOME L.P.

NOTES TO THE UNAUDITED PRO FORMA CONDENSED

COMBINED CONSOLIDATED FINANCIAL STATEMENTS (Continued)

Note 2. Basis of Pro Forma Presentation (Continued)

The pro forma financial statements were prepared using the acquisition method of accounting under GAAP and the regulations of the SEC. Atlantic Power has been treated as the acquirer in the transaction for accounting purposes. Acquisition accounting requires, among other things, that most assets acquired and liabilities assumed be recognized at fair value as of the acquisition date. In addition, acquisition accounting establishes that the consideration transferred be measured at the closing date of the transaction at the then-current market price. Since acquisition accounting is dependent upon certain valuations and other studies that have yet to commence or progress to a stage where there is sufficient information for a definitive measurement, the pro forma financial statements are preliminary and have been prepared solely for the purpose of providing unaudited pro forma condensed combined consolidated financial information. Differences between these preliminary estimates and the final acquisition accounting will occur and these differences could have a material impact on the accompanying pro forma financial statements and the combined company's future results of operations and financial position.

Note 3. Significant Accounting Policies

Based upon Atlantic Power's initial review of CPILP's summary of significant accounting policies, as disclosed in the CPILP consolidated historical financial statements elsewhere in this prospectus, as well as on preliminary discussions with CPILP's management, the pro forma condensed combined consolidated financial statements assume there will be significant adjustments necessary to conform CPILP's accounting policies under International Financial Reporting Standards ("IFRS") to Atlantic Power's accounting policies under U.S. GAAP. Upon completion of the transaction and a more comprehensive comparison and assessment, differences may be identified that would necessitate changes to CPILP's future accounting policies and such changes could result in material differences in future reported results of operations and financial position for CPILP as compared to historically reported amounts.

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ATLANTIC POWER CORPORATION AND CAPITAL POWER INCOME L.P.

NOTES TO THE UNAUDITED PRO FORMA CONDENSED

COMBINED CONSOLIDATED FINANCIAL STATEMENTS (Continued)

Note 4. Estimated Purchase Price and Preliminary Purchase Price Allocation

Atlantic Power is proposing to acquire all of the outstanding units of CPILP for a combination of either C$19.40 in cash or 1.3 Atlantic Power shares per CPILP unit. The purchase price for the business combination is estimated as follows (in thousands):

Fair value of consideration transferred:		
Cash	$	525,689
Equity		487,480
Total estimated purchase price		1,013,169
Preliminary purchase price allocation		
Working capital	$	10,932
Property, plant and equipment		1,040,133
Intangibles		633,620
Other long-term assets		129,883
Long-term debt		(704,885)
Other long-term liabilities		(110,585)
Deferred tax liability		(199,644)
Total identifiable net assets		799,454
Noncontrolling interest		(227,613)
Goodwill		441,328
Total estimated purchase price		1,013,169

The preliminary purchase price was computed using CPILP's outstanding units as of June 30, 2011, adjusted for the exchange ratio. The preliminary purchase price reflects the market value of Atlantic Power's common shares to be issued in connection with the transaction based on the closing price of Atlantic Power's common shares on the NYSE on June 30, 2011.

The allocation of the preliminary purchase price to the fair values of assets acquired and liabilities assumed includes pro forma adjustments to reflect the fair values of CPILP's assets and liabilities at the time of the completion of the transaction. The final allocation of the purchase price could differ materially from the preliminary allocation used for the Unaudited Pro Forma Condensed Combined Consolidated Balance Sheet primarily because power market prices, interest rates and other valuation variables will fluctuate over time and be different at the time of completion of the transaction compared to the amounts assumed in the pro forma adjustments.

Note 5. Pro Forma Adjustments to Financial Statements

The pro forma adjustments included in the pro forma financial statements are as follows:

(a) *Atlantic Power and CPILP historical presentation* Based on the amounts reported in the consolidated statements of operations and balance sheets of Atlantic Power and CPILP for the year ended December 31, 2010 and for the six months ended and as of June 30, 2011. Certain financial statement line items included in CPILP's historical presentation have been reclassified to corresponding line items included in Atlantic Power's historical presentation. These reclassifications had no impact on the historical operating income, net income from continuing operations or partners' equity reported

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ATLANTIC POWER CORPORATION AND CAPITAL POWER INCOME L.P.

NOTES TO THE UNAUDITED PRO FORMA CONDENSED

COMBINED CONSOLIDATED FINANCIAL STATEMENTS (Continued)

Note 5. Pro Forma Adjustments to Financial Statements (Continued)

by CPILP. The adjustments to total assets and liabilities were not material to CPILP's balance sheet.

(b)

CPILP conversion to US dollars Based on the amounts reported in the historical consolidated statements of operations of CPILP for the year ended December 31, 2010 and for the six months ended June 30, 2011, the amounts have been converted from Canadian dollars to US dollars using average exchange rates for the applicable periods. For the historical consolidated balance sheet as of June 30, 2011, the amounts have been converted from Canadian dollars to US dollars using ending exchange rates for that period. The adjustments to total assets, total liabilities, revenues and expenses were not material to CPILP's consolidated balance sheet and income statements.

(c)

CPILP conversion to U.S. GAAP Based on the amounts reported in the consolidated statements of operations and balance sheets of CPILP for the year ended December 31, 2010 and for the six months ended and as of June 30, 2011, certain financial statement line items included in CPILP's historical presentation have been reclassified or adjusted to conform to U.S. GAAP presentation. For the six months ended June 30, 2011, the CPILP statements conform to the IFRS and for the year ended December 31, 2010 the CPILP statements conform to Canadian GAAP. The adjustments to total assets, total liabilities, revenues and expenses were not material to CPILP's consolidated balance sheet and income statements.

(d)

CPILP exclusion of the North Carolina Plants CPILP will sell its Roxboro and Southport facilities located in North Carolina to an affiliate of Capital Power Corporation. Based on the amounts reported in the historical consolidated statements of operations and balance sheets of CPILP for the year ended December 31, 2010 and for the six months ended and as of June 30, 2011, the following amounts have been excluded from the unaudited pro forma condensed combined consolidated financial statements:

	Six months ended June 30, 2011	Year ended December 31, 2010
Project revenue	$ 24,210	$ 34,726
Project expenses		
Fuel	13,787	24,816
Project operations and maintenance	10,843	15,916
Depreciation and amortization	4,539	8,936
	29,169	49,668
Project loss	(4,959)	(14,942)
Administration	1,032	3,438
Net loss	$ (5,991)	$ (18,380)

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ATLANTIC POWER CORPORATION AND CAPITAL POWER INCOME L.P.

NOTES TO THE UNAUDITED PRO FORMA CONDENSED

COMBINED CONSOLIDATED FINANCIAL STATEMENTS (Continued)

Note 5. Pro Forma Adjustments to Financial Statements (Continued)

	As of June 30, 2011
Assets held for sale	$ 130,613
Liabilities held for sale	(15,367)
Retained earnings	$ 115,246

(e)

Power Purchase Agreements and Plants The pro forma balance sheet includes pro forma adjustments to reflect the fair value of CPILP's power contracts (including those designated as "normal purchases normal sales") recorded to intangible assets and additional fair value of plants in the amounts of $353.3 million and $136.5 million, respectively. The pro forma statements of operations include pro forma adjustments to reflect the increase in expense resulting from the amortization of the valuation adjustment related to CPILP's intangibles and the depreciation of the plants of $21.9 million and $40.4 million for the six months ended June 30, 2011 and the year ended December 31, 2010, respectively. The pro forma estimated annual amortization for the power contracts is $39.3 million based on the timing and fair value of the underlying contracts. This estimate is preliminary, subject to change and could vary materially from the actual adjustments at the time the transaction is completed, driven by various factors including changes in energy commodity prices and fuel prices.

(f)

Debt and Equity issuance The pro forma balance sheet includes a pro forma adjustment of $425.0 million to reflect Atlantic Power's proceeds from third-party debt and proceeds of $200.0 million from the issuance of 13.1 million common shares. The assumptions for the $425.0 million debt facility include a term of 5 years at 6.00% per annum. The proceeds from the debt and equity offering will be used to pay the CPILP unitholders the cash portion of the purchase price. The debt and equity amounts are offset by $11.7 million and $10.1 million of transaction costs classified as deferred financing costs and a reduction of common stock, respectively. The pro forma statements of operations include pro forma adjustments to reflect the net incremental interest expense resulting from the new debt and amortization of deferred financing costs of $14.0 million and $27.8 million for the six months ended June 30, 2011 and the year ended December 31, 2010, respectively.

(g)

Transaction Costs The pro forma balance sheet includes a pro forma adjustment to accounts payable and accrued liabilities to reflect estimated transaction costs of $25.7 million. The transaction costs have been excluded from the pro forma statements of operations as they reflect non-recurring charges not expected to have a continuing impact on the combined results.

(h)

Goodwill The pro forma balance sheet includes a preliminary estimate of the allocation of the excess of the purchase price paid over the fair value of CPILP's identifiable assets acquired and liabilities assumed. The estimated purchase price of the transaction, based on the closing price of Atlantic Power's common shares on the NYSE on June 30, 2011, is $1,013.2 million, and the excess purchase price over the fair value of the identifiable net assets acquired is $441.3 million.

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ATLANTIC POWER CORPORATION AND CAPITAL POWER INCOME L.P.

NOTES TO THE UNAUDITED PRO FORMA CONDENSED

COMBINED CONSOLIDATED FINANCIAL STATEMENTS (Continued)

Note 5. Pro Forma Adjustments to Financial Statements (Continued)

(i)

Deferred Tax Assets and Liabilities: The pro forma balance sheet includes a preliminary estimated deferred tax impact of $40.6 million to deferred tax liabilities. This adjustment reflect the estimated deferred tax impacts of the acquisition on the balance sheet, primarily related to the reversal of the Atlantic Power's valuation allowance associated with its Canadian accumulated net operating losses as of June 30, 2011. For purposes of the unaudited pro forma condensed combined consolidated financial statements, deferred taxes are provided at the Canadian enacted statutory rate of 25%. This rate does not reflect Atlantic Power's effective tax rate, which includes other tax items, such as non-deductible items, as well as other tax charges or benefits, and does not take into account any historical or possible future tax events that may impact the combined company. When the transaction is completed and additional information becomes available, it is likely the applicable income tax rate will change.

The $159,874 deferred tax liability adjustment reflects the estimated deferred tax liability impact of the acquisition on the balance sheet, primarily related to estimated fair value adjustments for acquired tangible and intangible assets. For purposes of the unaudited pro forma condensed combined consolidated financial information, deferred taxes are provided at Atlantic Power's deferred tax rate of 33%, which includes the U.S. federal statutory income tax rate plus the Canadian statutory income tax rate. This rate does not reflect Atlantic Power's effective tax rate, which includes other tax items, such as state taxes, as well as other tax charges or benefits and does not take into account any historical or possible future tax events that may impact the combined company. When the transaction is completed and additional information becomes available, it is likely the applicable income tax rate will change.

(j)

Common Shares outstanding Reflects the elimination of the CPILP units offset by issuance of 31.5 million Atlantic Power common shares as part of purchase price and the issuance of 13.1 million Atlantic Power common shares in new equity. The pro forma weighted average number of basic shares outstanding is calculated by adding these additional share issuances to Atlantic Power's weighted average number of basic common shares outstanding for the six months ended June 30, 2011 or the year ended December 31, 2010. The following table illustrates these computations (in thousands):

(in thousands of shares)	Six months ended June 30, 2011	Year ended December 31, 2010
Atlantic Power's basic shares outstanding	68,116	61,706
Additional shares issued to CPILP unit holders	31,500	31,500
Additional shares on new equity issuance	13,141	13,141
Basic shares outstanding	112,757	106,347
Dilutive potential shares		
Convertible debentures	14,430	12,339
LTIP notional units	427	542
Potentially dilutive shares	127,614	119,228

Potentially dilutive shares from convertible debentures have been excluded from fully dilutive shares for the six months ended June 30, 2011 and for the year ended December 31, 2010 because their impact would be anti-dilutive.

ACQUISITION OF CPILP

The Arrangement Agreement and Plan of Arrangement

On June 20, 2011, we entered into an Arrangement Agreement, as amended effective July 25, 2011, with CPILP, a publicly traded Canadian limited partnership, CPILP's general partner and CPI Investments Inc., a holding company that owns 100% of the shares of the general partner and, together with the CPILP units held by the general partner, 29.18% of the outstanding CPILP units. An affiliate of Capital Power Corporation, a Canadian public company, holds a 49% voting interest and a 100% economic interest in CPI Investments Inc. and EPCOR Utilities Inc. holds the other 51% voting interest. The Arrangement Agreement provides that we will acquire, directly or indirectly, all of the issued and outstanding CPILP units pursuant to a plan of arrangement under the Canada Business Corporations Act. Under the terms of the Plan of Arrangement, CPILP unitholders will be permitted to exchange each of their CPILP units for, at their election, C$19.40 in cash or 1.3 Atlantic Power common shares. All cash elections will be subject to proration if total cash elections exceed approximately C$506.5 million and all share elections will be subject to proration if total share elections exceed approximately 31.5 million Atlantic Power common shares.

Under the Plan of Arrangement, we will indirectly acquire the 16,513,504 CPILP units held by CPI Investments Inc. and CPILP's general partner through the acquisition of all of the outstanding shares of CPI Investments Inc. on effectively the same basis as the acquisition of CPILP units under the Plan of Arrangement.

Atlantic Power shareholders will continue to hold our existing common shares after the Plan of Arrangement. Based on the number of Atlantic Power common shares expected to be outstanding immediately prior to the effective date of the Plan of Arrangement, and excluding the common shares to be sold in this offering, we estimate that upon completion of the Plan of Arrangement current Atlantic Power shareholders will own approximately 70% of the combined company and former CPILP unitholders will own approximately 30% of the combined company, in each case on a fully-diluted basis.

Pursuant to the Plan of Arrangement, CPILP will sell its Roxboro and Southport facilities located in North Carolina to an affiliate of Capital Power Corporation, a publicly traded Canadian company, for approximately C$121.4 million. Additionally, in connection with the Plan of Arrangement, the management agreements between certain subsidiaries of Capital Power Corporation and CPILP and certain of its subsidiaries will be terminated (or assigned to Atlantic Power) in consideration of a payment of C$10.0 million. Atlantic Power or its subsidiaries will assume the management of CPILP and intends to enter into a transitional services agreement with Capital Power Corporation for a term of up to 12 months following the completion of the Plan of Arrangement, which will facilitate the integration of CPILP into Atlantic Power.

The Arrangement Agreement contains customary representations, warranties and covenants. Among these covenants, CPILP and its affiliates have each agreed not to solicit alternative transactions, except that CPILP may respond to an alternative transaction proposal that constitutes, or would reasonably be expected to lead to, a superior proposal. In addition, we or CPILP may be required to pay a C$35.0 million fee if the Arrangement Agreement is terminated in certain circumstances.

Completion of the Plan of Arrangement is conditioned upon the receipt of certain governmental authorizations, consents, orders or other approvals, including but not limited to approval under the *Investment Canada Act*, the *Competition Act* (Canada), the *Hart-Scott-Rodino Antitrust Improvements Act of 1976*, as amended (United States) and the *United States Federal Power Act*. The Plan of Arrangement must also be approved by the Court of Queen's Bench of Alberta and both our shareholders and CPILP's unitholders. We currently expect to complete the Plan of Arrangement in the fourth quarter of 2011, subject to receipt of required shareholder/unitholder, court and regulatory approvals and the satisfaction or waiver of the financing and other conditions contained in the

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Arrangement Agreement. However, we cannot be certain that our acquisition of CPILP will be completed. See "Risk factors Risks related to the Plan of Arrangement."

A copy of the Arrangement Agreement, including the Plan of Arrangement, is included as an exhibit to our Current Report on Form 8-K filed with the Securities and Exchange Commission on June 24, 2011, which is incorporated by reference into this prospectus. The foregoing description of the proposed transaction and the Arrangement Agreement does not purport to be complete and is qualified in its entirety by reference to such exhibit.

The terms of the Arrangement Agreement are the result of arm's length negotiation between the parties and their respective advisors. Effective July 25, 2011, the Arrangement Agreement was amended to account for our receiving the written commitment of a Canadian chartered bank and another financial institution to structure, arrange, underwrite and syndicate a senior secured credit facility in the amount of $625 million, the termination of a commitment regarding certain bridge loans that we had entered into at the time of entering into the Arrangement Agreement and the correction of certain other references.

Reasons for the Arrangement Agreement and Plan of Arrangement

At a meeting held on June 19, 2011, our board of directors unanimously determined that the Arrangement Agreement and the transactions contemplated thereby, including the issuance of Atlantic Power common shares to CPILP unitholders necessary to complete the Plan of Arrangement, are in the best interests of Atlantic Power and are fair to its stakeholders. In reaching these determinations, our board of directors consulted with our management and legal, financial and other advisors, and also considered numerous factors, including the strategic and financial benefits of the Plan of Arrangement and other factors, which our board of directors viewed as supporting its decision.

The strategic benefits that our board of directors believes should result from the combination of Atlantic Power and CPILP include, among other things, the following:

- Atlantic Power will become a leading publicly traded power generation and infrastructure company, with a larger and more diversified portfolio of contracted power generation assets in the United States and Canada;

- the transaction will combine Atlantic Power's proven management team with CPILP's highly qualified operations, maintenance, commercial management, accounting, human resources, legal and other personnel;

- Atlantic Power's market capitalization and enterprise value are expected to increase significantly, which is expected to add liquidity and enhance access to capital to fuel the long term growth of Atlantic Power's asset base throughout North America;

- the combination will expand and diversify Atlantic Power's asset portfolio to include projects in Canada and regions of the United States where we do not currently have a presence;

- our enhanced geographic diversification is anticipated to lead to additional growth opportunities in those regions in which we did not previously operate; and

- the transaction will further diversify the fuel types used by Atlantic Power's projects to include additional hydro, biomass and natural gas.

Our board of directors also believes that the combination of Atlantic Power and CPILP will result in significant financial benefits to Atlantic Power's shareholders. These financial benefits include:

upon completion of the Plan of Arrangement, our board of directors anticipates being able to increase dividends by 5%, from C$1.094 to C$1.15 per share on an annual basis;

the transaction is expected to strengthen Atlantic Power's dividend sustainability for the foreseeable future with immediate accretion to cash available for distribution;

the transaction is expected to result in a significant improvement in Atlantic Power's dividend payout ratio starting in 2012;

the transaction extends Atlantic Power's average PPA term from 8.8 to 9.1 years and enhances the credit quality of Atlantic Power's power off-takers; and

following completion of the Plan of Arrangement, we expect to benefit from cost savings attributable to synergies from combining the two entities and eliminating the public company reporting costs for CPILP.

Financing Transactions

We intend to use the net proceeds from this offering to pay a portion of the cash consideration required under the Plan of Arrangement and related fees and expenses. We plan to fund the remainder of the cash consideration payable by us under the Plan of Arrangement, including related fees and expenses, with the net proceeds from a senior unsecured notes offering and/or drawings under a $625 million senior secured credit facility, each as described below.

Under a separate offering memorandum or otherwise, we may offer senior unsecured notes to fund a portion of the cash consideration payable by us under the Plan of Arrangement, pursuant to Rule 144A and Regulation S under the Securities Act. The completion of this offering of common shares is not subject to the completion of an offering of senior unsecured notes and the completion of an offering of senior unsecured notes will not be subject to the completion of this offering. No assurance can be given that a notes offering will be commenced or completed or, if completed, as to the final terms of the notes offering.

We do not intend to register any notes under the Securities Act or the securities laws of any other jurisdiction, and notes may not be offered or sold in the United States absent registration or an applicable exemption from registration requirements. Any such notes will be offered only to qualified institutional buyers in the United States pursuant to Rule 144A under the Securities Act and outside the United States pursuant to Regulation S under the Securities Act. This description and other information regarding a possible notes offering is included in this prospectus solely for information purposes. Nothing in this prospectus should be construed as an offer to sell, or the solicitation of an offer to buy, any notes.

We have received the written commitment of a Canadian chartered bank and another financial institution to structure, arrange, underwrite and syndicate a senior secured credit facility in the amount of $625 million in order to finance the cash consideration payable by us under the Plan of Arrangement. Funding under this facility is subject to certain conditions, including, without limitation, that there shall not have occurred a material adverse effect with respect to Atlantic Power, CPILP, CPI Income Services Ltd. and CPI Investments Inc. taken as a whole.

About Atlantic Power

We own and operate a diverse fleet of power generation and infrastructure assets in the United States. Our generation projects sell electricity to utilities and other large commercial customers under long-term power purchase agreements, which seek to minimize exposure to changes in commodity prices. Our power generation projects in operation have an aggregate gross electric generation capacity of approximately 1,948 MW, in which our ownership interest is approximately 871 MW. Our current portfolio consists of interests in 12 operational power generation projects across nine states, one biomass project under construction in Georgia, and a 500 kilovolt 84-mile electric transmission line located in California. We also own a majority interest in Rollcast Energy, a biomass power plant developer with several projects under development. Six of our projects are wholly-owned subsidiaries: Lake Cogen, Ltd., Pasco Cogen, Ltd., Auburndale Power Partners, L.P., Cadillac Renewable

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Energy, LLC, Piedmont Green Power, LLC (98%)and Atlantic Path 15, LLC. Our common shares trade on the NYSE under the symbol "AT" and on the TSX under the symbol "ATP."

About CPILP

CPILP's primary business is the ownership and operation of power plants in Canada and the United States, which generate electricity and steam, from which it derives its earnings and cash flows. CPILP's generation projects sell electricity to utilities and other large commercial customers under long-term PPAs, which seek to minimize exposure to changes in commodity prices. At present, CPILP's portfolio consists of 19 wholly-owned power generation assets located in both Canada (in the provinces of British Columbia and Ontario) and the United States (in the states of California, Colorado, Illinois, New Jersey, New York and North Carolina), a 50.15% interest in a power generation asset in Washington State, and a 14.3% common equity interest in Primary Energy Recycling Holdings LLC. CPILP's assets have a total net generating capacity of 1,400 MW and more than four million pounds per hour of thermal energy. The CPILP units trade on the TSX under the symbol "CPA.UN."

CPILP's power projects generate electricity and steam from a combination of natural gas, waste heat, wood waste, water flow, coal and tire-derived fuel. CPILP's Canadian operations consist of:

- four natural gas-fired plants with a combined generating capacity of 163 MW;
- two biomass, wood waste plants with a combined generating capacity of 101 MW; and
- two hydroelectric facilities with a combined generating capacity of 56 MW.

CPILP's United States operations consist of:

- one simple-cycle natural gas-fired power plant with a generating capacity of 300 MW;
- one combined-cycle natural gas-fired power plant with a generating capacity of 125 MW;
- seven natural gas-fired combined heat and power ("CHP") plants, three of which can also use distillate fuel, with a combined generating capacity of 440 MW and steam generating capacity of 2,537 mlbs/hr; and
- a hydroelectric plant with a total generating capacity of 60 MW.

Pursuant to the Plan of Arrangement, CPILP will sell its Roxboro and Southport facilities located in North Carolina to an affiliate of Capital Power Corporation, a publicly traded Canadian company, for approximately C$121.4 million.

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The following table summarizes each of CPILP's power plants in each of Canada and the United States, and their respective operating characteristics (other than the Roxboro and Southport facilities):

Project Name	Location	Type	Net MW	Economic Interest	Primary Electric Purchaser	Power Contract Expiry	Customer S&P Credit Rating
Calstock	Ontario	Biomass	35	100%	Ontario Electricity Financial Corporation	2020	AA-
Kapuskasing	Ontario	Natural Gas	40	100%	Ontario Electricity Financial Corporation	2017	AA-
Nipigon	Ontario	Natural Gas	40	100%	Ontario Electricity Financial Corporation	2012(1)	AA-
North Bay	Ontario	Natural Gas	40	100%	Ontario Electricity Financial Corporation	2017	AA-
Tunis	Ontario	Natural Gas	43	100%	Ontario Electricity Financial Corporation	2014	AA-
Mamquam	British Columbia	Hydro	50	100%	British Columbia Hydro and Power Authority	2027(2)	AAA
Moresby Lake	British Columbia	Hydro	6	100%	British Columbia Hydro and Power Authority	2022	AAA
Williams Lake	British Columbia	Biomass	66	100%	British Columbia Hydro and Power Authority	2018(3)	AAA
Frederickson	Washington	Natural Gas	125(4)	50.15%(5)	3 Public Utility Districts(6)	2022	A to A+
Greeley	Colorado	Natural Gas	72	100%	Public Service Company of Colorado	2013	A-
Manchief	Colorado	Natural Gas	300	100%	Public Service Company of Colorado	2022(7)	A-
Naval Station	California	Natural Gas	47	100%	San Diego Gas & Electric	2019	A
Naval Training Centre	California	Natural Gas	25	100%	San Diego Gas & Electric	2019	A
North Island	California	Natural Gas	40	100%	San Diego Gas & Electric	2019	A
Oxnard	California	Natural Gas	49	100%	Southern California Edison	2020	BBB+
Curtis Palmer	New York	Hydro	60	100%	Niagara Mohawk Power Corp.	2027	A-
Kenilworth	New Jersey	Natural Gas	30	100%	Schering-Plough Corporation	2012(8)	AA
Morris	Illinois	Natural Gas	177	100%	Equistar Chemicals, LP(9)	2023(10)	BB-

(1) CPILP has the option to extend the PPA for ten years at existing terms.

(2) BC Hydro has an option exercisable in 2021 and every five years thereafter to buy the Mamquam facility or extend the contract.

(3) BC Hydro has an option to extend the agreement by up to 10 years, on the basis of two five-year term extensions.

(4) In addition, there is 10 MW dust firing.

(5)

Represents CPILP's 50.15% ownership interest in Frederickson. Puget Sound Energy, Inc. owns the remaining 49.85% ownership interest.

(6) PUDs are: Benton (A+), Franklin (A) and Grays Harbor (A).

(7) Public Service Company of Colorado has an option during the latter part of the extension term to purchase the Manchief facility.

(8) Pursuant to the ESA, Schering-Plough Corporation has the option to purchase the Kenilworth facility. The ESA can be extended automatically for successive five year periods.

(9) 100 MW is sold forward through April 2014 into the Pennsylvania, New Jersey, and Maryland market.

(10) Equistar Chemicals, LP has a right to purchase the Morris facility at fair market value at the end of 2013, 2018 and 2023.

Power Purchase Agreements

Canada

Ontario

The Ontario Electricity Financial Corporation ("OEFC") is the sole purchaser of power from CPILP's five Ontario power plants. The power is purchased under long-term power purchase agreements. The earliest expiry date of these agreements is at the Nipigon plant where the initial term of the PPA expires in 2012 and the longest expiry date is at the Calstock plant where the PPA expires in 2020. CPILP reached an agreement with the OEFC to amend the Tunis PPA effective January 16, 2010 that allows CPILP to flow-through natural gas and transportation costs in excess of benchmark amounts to OEFC and extends OEFC the right to curtail the plant during summer off-peak periods through the remaining term of the PPA in 2014.

Williams Lake

The Williams Lake power plant sells power to the British Columbia Hydro and Power Authority ("BC Hydro") under a 25-year PPA with the initial term expiring in 2018. BC Hydro has an option to extend the agreement by up to 10 years, on the basis of two five-year term extensions.

The Williams Lake Electricity Purchase Agreement ("EPA") contains two pricing tranches: a firm energy tranche, representing approximately 82% of total energy produced; and a surplus energy tranche, representing approximately 18% of total energy produced. The firm energy tranche price consists of a fixed energy component, an operations and maintenance component (adjusted annually for average weekly earnings in British Columbia), and a reimbursable cost component. The surplus energy tranche price is adjusted annually for changes in the Dow Jones California Oregon Border index. The year end surplus energy tranche price would have been set at C$32/MWh for 2010, compared to C$58/MWh for 2009. However CPILP sold the surplus energy to a third party at a higher price. The surplus energy price for 2011 was set through negotiations with BC Hydro and is attractive.

Mamquam

The Mamquam hydroelectric facility sells all of its electricity generated to BC Hydro under a long-term contract (the "Mamquam EPA") which will expire in October 2027. BC Hydro has an option, exercisable in 2021 and every five years thereafter, to either purchase the Mamquam facility or extend the Mamquam EPA.

Energy rates payable under the Mamquam EPA consist of a fixed energy component, an operations and maintenance component (adjusted annually for inflation), and a reimbursable cost component which covers costs such as property taxes, water and land use fees as well as comprehensive liability insurance costs.

Moresby Lake

The Moresby Lake hydroelectric facility sells substantially all its electricity to BC Hydro under a long-term contract (the "Moresby Lake PPA") which will expire in 2022.

The energy rate payable by BC Hydro under the Moresby Lake PPA consists of a fixed energy component adjusted annually for inflation.

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United States

Frederickson

CPILP's portion (50.15% or approximately 125 MW) of the Frederickson facility's base 249 MW generating capacity has been sold under PPAs to three Washington State Public Utility Districts ("PUDs") for a term of 20 years ending in 2022. Under the PPAs, CPILP provides generating capacity and associated energy to each PUD, and the PUDs pay CPILP a capacity charge, a fixed operations and maintenance charge, a variable operations and maintenance charge and a fuel charge. The PUDs must supply their proportionate share of natural gas to CPILP at Huntingdon, British Columbia. CPILP is responsible for contracting firm transportation for natural gas from Huntingdon to the Frederickson facility. CPILP is responsible for any fixed and variable cost increases above those recoverable under the PPAs, other than costs that result from the effects of material changes to environmental and tax laws.

Manchief

The Manchief power plant operates under a PPA with the Public Service Company of Colorado ("PSCo") that expires in 2022. PSCo is an electricity and natural gas distribution company that primarily serves northern Colorado. Under the PPA, PSCo purchases: (i) the electricity capacity consisting of 301.8 MW of net generating capacity per hour, or the actual net generating capacity that is available in any given hour, whichever is less; and (ii) the electrical energy which is actually dispatched by PSCo and associated with such capacity, and Manchief is paid capacity and energy payments. Capacity payments are typically stable and are made on a monthly basis, regardless of whether the plant is actually dispatched by PSCo. Energy payments are also made on a monthly basis and are comprised of tolling fees, start-up fees, heat rate adjustment payments (payable either to or by Manchief) and natural gas transportation charges. Starting in May 2012, the capacity payments will be reduced by approximately 15% under the tolling arrangement.

Manchief obtains operations and maintenance services for its generating facility from Colorado Energy Management, LLC pursuant to the terms of a plant operating and maintenance agreement.

CPILP and PSCo have also signed an Option Agreement under which PSCo has the right, during the latter part of the PPA term, to acquire the Manchief power plant. If PSCo exercises the purchase option, CPILP would receive a fixed purchase price, as specified in the Option Agreement, which management believes will maintain the economic value of the term and compensate CPILP for the power plant's expected residual value.

Greeley

The Greeley facility provides all of its electrical output to PSCo under an on-system PPA which expires in August 2013. PSCo pays the Greeley facility a monthly capacity payment and energy payment pursuant to the PPA. CPILP entered into a three-year forward natural gas swap contract expiring in October 2011 that covers most of the anticipated supply requirements for the Greeley facility during this period. Extension of the forward swap to cover the expiry of the PPA is being evaluated by management.

Under a development agreement between Ventures and KN/Thermo LLC, KN/Thermo LLC is currently entitled to up to 33.5% of the Pre-Tax Cash Flow from the Greeley facility. Pre-Tax Cash Flow is defined in the development agreement to include the net proceeds realized by CPILP from the sale of the Greeley facility under certain circumstances, and cash proceeds received from operation of the Greeley facility (including from sales of electric power and hot water), as reduced by the reasonable operating costs of the facility.

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California Facilities

CPILP's California facilities are comprised of three facilities located on U.S. naval bases (the "Naval Facilities") and the Oxnard facility.

The Naval Facilities are comprised of Naval Station, North Island and Naval Training Center. Except for the 4 MW steam turbine at the North Island facility, each of the Naval Facilities provides all of its electrical output to San Diego Gas and Electric Company ("SDG&E") under the terms of the Long Run Standard Offer No. 4 for Power Purchase and Interconnection agreements from Qualifying Facilities, each of which expire in 2019. SDG&E is an electricity and natural gas distribution company primarily serving the San Diego area. Each of the Naval Facilities is required to operate throughout the term of the applicable PPA as a Qualifying Facility ("QF") in accordance with the cogeneration facility requirements established by the Federal Energy Regulatory Commission ("FERC").

In 2009, CPILP completed an upgrade to its gas turbine at the North Island facility in southern California from a GE LM5000 to a GE LM6000 unit for an approximate cost of US$17.0 million. The repowering project was completed in time for the summer peak demand season in southern California. The project improved the operating efficiency of the facility reducing the gas turbine gross heat rate by approximately 1,127 Btu/kWh. The replaced LM5000 unit is available as a spare gas turbine for CPILP's other LM5000 turbines. The energy produced by the 4 MW steam turbine at the North Island facility is sold to the U.S. Navy at a discount to SDG&E's retail rates. The energy produced by the 2.5 MW steam turbine at the Naval Training Center is sold to SDG&E under a Standard Offer No. 1 for Power Purchase and Interconnection from Qualifying Facilities ("SO1"). The energy rates under the SO1 are the SDG&E short run avoided cost ("SRAC") rates. Capacity payments are paid on an as-available basis under rates that are reviewed by the California Public Utility Commission ("CPUC") periodically.

The Navy has the right to terminate the Naval Facility Negotiated Utility Service Contracts ("NUSCs") for convenience on one year's notice. Termination costs incurred under the PPA would be reimbursed under the NUSC in the event of termination for convenience. See "Thermal Supply Agreements."

The Oxnard facility provides all of its natural gas turbine electrical output to Southern California Edison Company ("SCE") under a contract that expires in 2020. SCE is an electricity and natural gas distribution company primarily serving areas of southern California outside Los Angeles and San Diego. The Oxnard facility is required to operate throughout the term of the Oxnard PPA meeting QF efficiency standards in accordance with the cogeneration facility requirements established by the FERC. The Oxnard facility is qualified as both a QF and an Exempt Wholesale Generator ("EWG").

In May 2010, CPILP completed the replacement of the existing GE LM5000 natural gas turbine with a more efficient and reliable GE LM6000 at Oxnard at a cost of US$19.3 million. The final capital cost could potentially be lower if the sale of the used General Electric LM5000 turbine is successful. The repowering project was completed in time for the summer peak demand season in southern California. While the project improved the Oxnard facility heat rate by 2.4%, the primary economic driver of the project is an expected reduction in forced outage costs relative to the GE LM5000.

The price paid under the Naval Facilities' PPAs includes a capacity payment and an energy payment based on SDG&E's SRAC. The price paid under the Oxnard PPA includes a capacity payment and an energy payment based on SCE's SRAC. Capacity payments are based on achieving availability performance targets. These performance requirements require that forced outage rates for the facility are to be less than 20% during specified on-peak hours during the summer peak demand months. An additional performance bonus is applied when on-peak forced outage rates are less than 15%. Each of

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the Naval Facilities and the Oxnard facility has historically achieved its firm capacity revenue and near maximization of capacity bonus revenues.

On September 20, 2007, the CPUC accepted an alternative decision regarding revisions to the SRAC formulae that became effective August 1, 2009. The essence of the decision was to provide a 50/50 split between market and administratively determined heat rates for the calculation of the overall heat rate used in the energy price calculation; provide an escalating operating and maintenance fee adder; and use a 12-month forward-looking market heat rate rather than the historical pricing. The SRAC change impacts the steam payment component of the Naval Facilities PPAs and CPILP is currently in discussions with the Navy regarding implications of future steam pricing.

SRAC energy prices are published monthly in accordance with the above mentioned decision. As such, this pricing provision recovers the month-to-month natural gas costs related to electricity production and substantially passes through the fuel cost to SDG&E and SCE in the variable energy charge. Time of use factors are applied to the SRAC energy rate to value the electricity delivered during on-peak hours relative to electricity delivered during off-peak hours. The Oxnard facility typically operates during on-peak hours in order to take advantage of higher electricity prices provided from on-peak time of use rates. Changes in natural gas prices have a nominal impact on the Oxnard facility's operating margin.

Curtis Palmer

The Curtis Palmer hydroelectric facility sells all power generated to Niagara Mohawk Power Corporation ("Niagara") under a long-term contract. The Curtis Palmer PPA ends after the earlier of 2027 and the delivery to Niagara of a cumulative 10,000 GWh of electricity.

The Curtis Palmer PPA sets out 11 different prices for electricity sold to Niagara, with the applicable price to be paid at any given time being dependent upon the cumulative GWh of electricity which have been delivered to Niagara. In December 2008, the pricing increased by 18% as the plant moved into the sixth pricing block. Over the remaining term of the PPA, the price increases by US$10/MWh with each additional 1,000 GWh of electricity delivered. The plant requires approximately three years to move through each 1,000 GWh block, depending upon river flow.

Under certain circumstances, Niagara has the ability to relocate, rearrange, retire or abandon its transmission system which would potentially give rise to material future capital cost outlays by Curtis Palmer to maintain its interconnection.

Morris

The Morris facility sells electrical energy to Equistar Chemicals, LP ("Equistar"), a wholly-owned subsidiary of LyondellBasell AF S.C.A. (LyondellBasell), under an Energy Supply Agreement ("ESA") that expires in 2023. Pursuant to the Morris ESA, Equistar pays a tiered energy rate based on the amount of energy consumed to a maximum of 77 MW. Equistar also pays capacity fees, comprised of both a non-escalating fixed fee that expires in 2013 and a variable fee that escalates with materials and labour indices and expires in 2023. The non-escalating capacity payment is fixed at US$8.3 million per year. In addition, the Morris facility earns energy payments based on electricity and steam delivered that is adjusted monthly for natural gas prices. Based on the energy payment formula, there is a small portion of energy costs that are not recovered through the energy payments, and this non-recoverable amount fluctuates with the price of natural gas. Most of this natural gas price exposure has been hedged through 2011. Equistar has a right to purchase the Morris facility at fair market value at the end of 2013, 2018 and 2023. The Morris facility is certified as a QF.

Excess capacity and energy above the needs of Equistar can be sold into the Pennsylvania, New Jersey, and Maryland ("PJM") market. 100 MW of electrical capacity has been sold through the PJM market from May 2011 to April 2014 at auction prices.

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On January 6, 2009, Equistar, along with LyondellBasell's other North American operating entities, filed a voluntary petition for reorganization under Chapter 11 of the U.S. Bankruptcy Code. Since that date, Equistar made all post-petition payments required under the ESA. On April 23, 2010 the plan of reorganization for LyondellBasell's U.S. subsidiaries, including Equistar, under Chapter 11 of the U.S. Bankruptcy Code was approved. Pursuant to the plan of reorganization, Equistar assumed the Morris ESA, and as a result, CPILP received a US$12.4 million payment for pre-petition services under the ESA along with interest.

Kenilworth

The Kenilworth facility sells electrical energy to Schering-Plough Corporation ("Schering"), a subsidiary of Merck & Co., Inc., under an amended and extended ESA that expires in July 2012. Pursuant to the Kenilworth ESA, Schering pays an energy rate that escalates annually. The Kenilworth ESA imposes a minimum take or pay obligation on Schering of 125,000 MWh per year. Load growth at Schering's facility over the years has caused certain seasonal loads to match more closely with the capacity of the Kenilworth facility. Excess generation above the Schering loads are sold to Public Service Enterprise Group Incorporated under a contract entered into in 2009.

Thermal Supply Agreements

The Greeley facility sells hot water to the University of Northern Colorado ("UNC") pursuant to a Thermal Supply Agreement ("TSA") which expires in August 2013. Under the Greeley TSA, the Greeley facility is obligated to deliver for sale to UNC only such heat energy as is generated during the production of electrical capacity and energy for sale to PSCo. The charge per million Btu of thermal energy is calculated in a manner that gives UNC a discount when compared to UNC avoided natural gas-fired boiler costs.

The Naval Facilities sell steam to the Navy pursuant to NUSCs, each of which expires in February 2018. The Naval Facility NUSCs give the Navy a right to purchase electrical energy from the Naval Facilities at prices comparable to those under the Naval Facility PPAs. Under the Naval Facility NUSCs, the Navy has an obligation to consume enough thermal energy for the Naval Facilities to maintain their QF status. The Navy has the right to terminate the NUSCs for convenience on one year's notice. The Navy is obligated to pay a termination payment if it breaches an agreement or causes any loss of a Naval Facility's QF status.

The contracted steam for the Naval Facilities is based on a take or pay formula using a specified volume at each facility. Additional steam can be taken above these specified volumes and such steam is priced at avoided package boiler costs. The monthly price payable by the Navy for steam under the Naval Facility NUSCs includes: (i) a steam commodity charge; (ii) fixed service charge for plant capital and operations and maintenance avoidance; and (iii) water cost pass-through provisions, a feed water charge and a credit for condensate return.

Steam pricing is linked to the cost of natural gas and SDG&E's SRAC by an energy sharing formula. This formula provides the Naval Facilities with reduced price volatility as the SRAC price of electricity primarily increases or decreases as a result of changes to the price of natural gas. Changes in natural gas prices have a nominal impact on the Naval Facilities' cash provided by operating activities. On September 20, 2007, the CPUC accepted an alternative decision regarding revisions to the SRAC formulae that became effective on August 1, 2009.

The Oxnard facility supplies steam to its anhydrous ammonia absorption refrigeration plant, which then provides refrigeration services to Boskovich Farms at no charge; thereby maintaining the Oxnard facility's QF status.

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The Morris facility sells steam to Equistar to a maximum of 720 million lbs/hr under the Morris ESA through 2023. Ten year average usage is approximately 320 million lbs/hr. The Morris ESA charge for steam is calculated on the basis of a tiered pricing schedule ranging from US$2.60/mlbs of steam to US$3.18/mlbs of steam depending on quantity of average monthly steam demand. The agreement provides for the option to renegotiate pricing if steam demand falls outside a set range for a stipulated period of time.

The Kenilworth facility sells steam to Schering under an amended and extended Kenilworth ESA that expires in July 2012. The Kenilworth ESA provides for a contract minimum of 160,000 million Btu per year. The average annual heat content of steam sales directly from the Kenilworth facility under the terms of the Kenilworth ESA has been higher (740,000 million Btu per year average) than the contract minimum. The Kenilworth ESA charge per million Btu of steam is calculated as a function of the delivered cost of fuel to Schering's auxiliary boilers. Schering is able to request long term purchase strategies to minimize the monthly volatility of natural gas prices.

Fuel Purchase Agreements

The largest of CPILP's expenses is the cost of fuel used in the generation of electricity. Fuel costs include the natural gas commodity price, natural gas transportation charges, waste heat optimization costs and wood waste costs at the Calstock and Williams Lake plants. Wood waste costs include the cost of wood waste, the transportation of wood waste, fuel and management costs and the disposal of wood ash. Although wood waste and the related transportation services have been purchased under contract for the majority of the fuel requirements at the Calstock and Williams Lake facilities, the suppliers have no obligation to provide in the event they scale back or shut down operations.

CPILP purchases fuel gas and/or waste heat for each of the Ontario power plants except Tunis, under long-term natural gas and waste heat supply agreements. CPILP reached an agreement with the OEFC to amend the Tunis PPA effective January 16, 2010 that allows CPILP to flow-through natural gas and transportation costs in excess of benchmark amounts to OEFC and extends OEFC the right to curtail the plant during summer off-peak periods through the remaining term of the PPA in 2014. Firm capacity for the transportation of fuel gas to the Ontario power plants has been contracted for on the TransCanada natural gas transmission system under long-term transportation agreements, the earliest of which expires in 2011.

In late 2008, CPILP completed a new supply agreement with a nearby wood waste landfill site for Calstock. The landfill site is estimated by management to have equivalent to one million green metric tons of supply, which is equal to three years of supply for the plant. Pursuant to a Certificate of Approval ("CoA") from the Ministry of Environment, Calstock successfully completed a rail ties test burn in November 2009. CPILP has applied for a permanent CoA amendment from the Ministry of Environment. If approved, the rail ties could provide up to 20% of the Calstock facility's fuel requirement.

Wood waste supply to the Williams Lake facility was sufficient in 2010. Traditional suppliers returned to near normal production levels with the exception of one supplier who continues to idle one of their sawmills. CPILP has identified other sources of supply to replace volume lost from the curtailed sawmill. These sources are more expensive; however, approximately 82% of the fuel cost is borne by BC Hydro under the EPA. The facility is well positioned to withstand potential fuel shortages largely due to an agreement with Pioneer Biomass Inc. to supply processed forest based residuals, on an as needed basis, to the Williams Lake facility. Fuel inventory levels were reduced significantly in 2010 to bring back to normal operating levels. The expanded wood waste storage capacity continues to provide flexibility in managing available lower cost wood waste supplies. At December 31, 2010, the plant had sufficient wood waste inventory for the plant to produce its maximum output of 66 MW for 35 days at full output.

Natural gas supply purchased for the Greeley facility is financially fixed under an agreement with Shell Energy North America and CP Energy Marketing (US) Inc. which expires in October 2011. Natural gas for the Naval Facilities and Oxnard is purchased through natural gas contracts with RBS Sempra Energy Trading Corporation (Sempra) at monthly index prices similar to those used in the utility SRAC calculations. Kenilworth natural gas is also purchased from Sempra with that price used directly in the steam pricing under the ESA. The Morris facility obtains the majority of its required natural gas through a Purchase and Sale Agreement with DCP Midstream Marketing LP and Tenaska Power Services Co. (Tenaska) which expires in 2014 at a price indexed to the Chicago City Gate market. Under the agreement, Tenaska also provides power market trading services through a year-to-year agreement that may be cancelled on 60 days notice. Additionally, the Morris facility contracts gas storage facility as a seasonal hedge and to maximize operational flexibility.

Waste Heat Agreements

Pursuant to long-term waste heat agreements, TransCanada provides the Ontario power plants with all waste heat generated by the natural gas turbine compressors located at the compressor stations adjacent to the Ontario power plants on an as available basis. Each agreement continues in effect for as long as CPILP delivers electrical energy from the particular plant. The waste heat agreements provide that TransCanada will be obligated to supply waste heat to the Ontario power plants only when such waste heat is available from the compressor stations. In the event waste heat output is reduced at a compressor station as a result of reduced natural gas turbine output arising from any cause, TransCanada's obligation to deliver waste heat is reduced accordingly.

In 2003, CPILP entered into an agreement with TransCanada to optimize the waste heat availability at certain of CPILP's Ontario plants. Under the agreement, CPILP pays for incremental natural gas used in the compressor station turbines to optimize the quantities of waste heat which can be available to CPILP's adjacent power plant. Any incremental maintenance or repair costs as a result of the increased use of TransCanada's turbines are also charged to CPILP.

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SECURITY OWNERSHIP OF CERTAIN BENEFICIAL OWNERS AND MANAGEMENT

The following table sets forth information regarding the beneficial ownership of our common shares as of September 14, 2011 with respect to:

- each person (including any "group" of persons as that term is used in Section 13(d)(3) of the Exchange Act) who is known to us to be the beneficial owner of more than 5% of our outstanding common shares (none as of September 14, 2011);
- each of our directors;
- each of our named executive officers; and
- all of our directors and named executive officers as a group.

The address of each beneficial owner listed in the following table is c/o Atlantic Power Corporation, 200 Clarendon Street, Floor 25, Boston, MA 02116.

Except as otherwise indicated in the footnotes to the following table, we believe, based on the information provided to us, that the persons named in the following table have sole voting and investment power with respect to the shares they beneficially own, subject to applicable community property laws.

Owner	Number of common shares beneficially owned	Percentage of common shares beneficially owned(1)
Directors and named executive officers		*
Irving R. Gerstein	10,400	*
Kenneth M. Hartwick	57,485(2)	*
John A. McNeil	12,500	*
R. Foster Duncan(3)	1,500	*
Holli Nichols(3)	2,550(2)	*
Barry E. Welch	223,105	*
Paul H. Rapisarda	40,009	*
William B. Daniels	7,173	*
John J. Hulburt	4,643	*
All directors and named executive officers as a group (9 persons)	359,365	0.01

* Less than l%.

(1) The applicable percentage ownership is based on 68,639,654 common shares issued and outstanding as of June 30, 2011.

(2) Common shares beneficially owned include units held in our Deferred Share Unit Plan of 55,485 for Ken Hartwick and 2,550 for Holli Nichols.

(3) Joined our board of directors in June 2010.

DESCRIPTION OF COMMON SHARES

The following summary description sets forth some of the general terms and provisions of our common shares. Because this is a summary description, it does not contain all of the information that may be important to you. For a more detailed description of our common shares, you should refer to the provisions of our Articles of Continuance, which we refer to as our "Articles."

The last reported sale price of our common shares on the TSX on September 14, 2011 was C$14.65 per common share, and the last reported sale price of our common shares on the NYSE on September 14, 2011 was $14.79 per common share.

Common Shares

Our Articles authorize an unlimited number of common shares. At the close of business on September 14, 2011, 68,984,192 of our common shares were issued and outstanding.

Our common shares are listed on the TSX under the symbol "ATP" and began trading on the NYSE under the symbol "AT" on July 23, 2010. Holders of our common shares are entitled to receive dividends as and when declared by our board of directors and are entitled to one vote per common share on a vote by poll, or one vote per person present who is a shareholder or a proxy holder for a vote by show of hands, in each case with respect to all matters to be voted on at meetings of shareholders. We are limited in our ability to pay dividends on our common shares by restrictions under the Business Corporations Act (British Columbia), which we refer to as the "BC Act," relating to our solvency before and after the payment of a dividend. Holders of our common shares have no preemptive, conversion or redemption rights and are not subject to further assessment by us.

Upon our voluntary or involuntary liquidation, dissolution or winding up, the holders of common shares are entitled to share ratably in the remaining assets available for distribution, after payment of liabilities.

Holders of our common shares will have one vote for each common share held at meetings of our common shareholders on a vote by poll, and one vote per person present who is a shareholder or a proxy holder for a vote by show of hands.

Pursuant to our Articles and the provisions of the BC Act, certain actions that may be proposed by us require the approval of our shareholders. We may, by special resolution and subject to our Articles, increase our authorized capital by such means as creating shares with or without par value or increasing the number of shares with or without par value. We may, by special resolution and subject to the BC Act, alter our Articles to subdivide, consolidate, change from shares with par value to shares without par value or from shares without par value to shares with par value or change the designation of all or any of our shares. We may also, by special resolution and subject to the BC Act, alter our Articles to create, define, attach, vary, or abrogate special rights or restrictions to any shares. Under the BC Act and our Articles, a special resolution is a resolution passed at a duly-convened meeting of shareholders by not less than two-thirds of the votes cast in person or by proxy at the meeting, or a written resolution consented to by all shareholders who would have been entitled to vote at the meeting of shareholders.

Certain provisions of our Articles and the BC Act

We are governed by the BC Act. Our Articles 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.

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Advance notice procedures

Our Articles establish an advance notice procedure for "special business" and shareholder proposals to be brought before a meeting of shareholders. For special business, advance notice describing the special business to be discussed at the meeting must be provided and that notice must include any documents to be approved or ratified as an addendum or state that such document will be available for inspection at our records office or other reasonably accessible location. Shareholders at an annual meeting may not consider proposals or nominations that are not specified in the notice of meeting or brought before the meeting by or at the direction of the board of directors or by a shareholder of record on the record date for the meeting or a proxyholder who is entitled to vote at the meeting.

Advance notice procedures

Under the BC Act, shareholders may make proposals for matters to be considered at the annual general meeting of shareholders. Such proposals must be sent to us in advance of any proposed meeting by delivering a timely written notice in proper form to our registered office. The notice must include information on the business the shareholder intends to bring before the meeting. These provisions could have the effect of delaying until the next shareholder meeting shareholder actions that are favored by the holders of a majority of our outstanding voting securities.

Shareholder requisitioned meeting

Under the BC Act, shareholders holding $^{1}/_{20}$ of our outstanding common shares may request the directors to call a general meeting of shareholders to deal with matters that may be dealt with at a general meeting, including election of directors. If the directors do not call the meeting within the timeframes specified in the BC Act, the shareholder can call the meeting and we must reimburse the costs.

Removal of directors and increasing board size

Under our Articles, directors may be removed by shareholders by passing an ordinary resolution of a simple majority of shareholders with the right to vote on such resolution. Further, under our Articles and subject to the BC Act, the directors may appoint additional directors up to one-third of the directors elected by the shareholders.

Canadian Securities Laws

We are a reporting issuer in Canada and therefore subject to the securities laws in each province and territory in which we are reporting. Canadian securities laws require reporting of share purchases and sales by shareholders holding more than 10% of our common shares, including certain prescribed public disclosure of their intentions for their holdings. Canadian securities laws also govern how any offer to acquire more than 20% of our equity or voting shares must be conducted.

Transfer Agent and Registrar

Computershare Investor Services Inc. and Computershare Trust Company, N.A. serve as our transfer agents and registrars for our common shares.

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CERTAIN UNITED STATES FEDERAL INCOME TAX CONSIDERATIONS

The following general summary describes certain U.S. federal income tax considerations for U.S. Holders (as defined below) of our common shares. This summary does not address all of the tax considerations that may be relevant to certain types of U.S. Holders subject to special treatment under U.S. federal income tax laws, such as:

- persons who do not hold common shares as capital assets;
- dealers in securities or currencies;
- financial institutions;
- regulated investment companies;
- real estate investment trusts;
- tax-exempt entities (including private foundations);
- qualified retirement plans, individual retirement accounts, and other tax-deferred accounts;
- insurance companies;
- persons holding common shares as a part of a hedging, integrated, conversion or constructive sale transaction or a straddle;
- persons that own, directly, indirectly or as a result of certain constructive ownership rules, common shares representing 10% or more of the voting power in Atlantic Power;
- traders in securities that elect to use a mark-to-market method of accounting;
- persons liable for alternative minimum tax;
- U.S. Holders whose "functional currency" is not the U.S. dollar; or
- U.S. tax expatriates and certain former citizens and long-term residents of the United States.

This summary is based upon the provisions of the United States Internal Revenue Code of 1986 (as amended, the "Code"), the United States Treasury Regulations promulgated thereunder, and administrative and judicial interpretations of the Code and the United States Treasury Regulations, all as currently in effect, and all subject to differing interpretations or change, possibly on a retroactive basis. This summary does not address any estate, gift, state, local, non-U.S. or other tax consequences, except as specifically provided herein.

For purposes of this summary, a "U.S. Holder" means a person that holds common shares that is, for U.S. federal income tax purposes:

an individual who is a citizen or resident of the U.S. (as determined under U.S. federal income tax rules);

a corporation (or other entity taxable as a corporation for U.S. federal income tax purposes) created or organized in or under the laws of the United States or of any political subdivision thereof;

an estate, the income of which is subject to U.S. federal income taxation regardless of its source; or

a trust if it (i) is subject to the primary supervision of a court within the United States and one or more U.S. persons have the authority to control all substantial decisions of the trust or (ii) has in effect a valid election under applicable United States Treasury Regulations to be treated as a U.S. person.

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If a partnership or an entity treated as a partnership for U.S. federal income tax purposes holds common shares, the U.S. federal income tax treatment of a partner in the partnership will generally depend on the status of the partner and the activities of the partnership. Partnerships or a partner in a partnership holding common shares should consult their own tax advisor regarding the consequences of the ownership and disposition of common shares by the partnership.

The following summary is of a general nature only and is not a substitute for careful tax planning and advice. U.S. Holders of common shares are urged to consult their own tax advisors concerning the U.S. federal income tax consequences of the issues discussed herein, in light of their particular circumstances, as well as any considerations arising under the laws of any foreign, state, local or other taxing jurisdiction.

Taxation of distributions on common shares

The gross amount (i.e., before Canadian withholding tax) of distributions to a U.S. Holder on our common shares (other than distributions in liquidation or in redemption of stock that are treated as exchanges) will be treated as a dividend, to the extent paid out of our current or accumulated earnings and profits (as determined under U.S. federal income tax principles). Such dividend will be includible in a U.S. Holder's gross income on the day actually or constructively received. Distributions to a U.S. Holder in excess of earnings and profits will be treated first as a return of capital that reduces a U.S. Holder's tax basis in such common shares (thereby increasing the amount of gain or decreasing the amount of loss that a U.S. Holder would recognize on a subsequent disposition of our common shares), and then as gain from the sale or exchange of such common shares.

Non-corporate U.S. Holders will generally be eligible for the preferential U.S. federal rate on qualified dividend income for tax years beginning on or before December 31, 2012, provided that we are a "qualified foreign corporation," the stock on which the dividend is paid is held for a minimum holding period, and other requirements are satisfied.

A qualified foreign corporation includes a foreign corporation that is not a PFIC (as defined below) in the year of the distribution or in the prior tax year and that is eligible for the benefits of an income tax treaty with the United States, if such treaty contains an exchange of information provision and the United States Treasury Department has determined that the treaty is satisfactory for purposes of the legislation. Based on current law and applicable administrative guidance, our dividends paid before December 31, 2012 should be eligible for treatment as qualified dividend income, provided the holding period and other requirements are satisfied. In the absence of intervening legislation, dividends received by a U.S. Holder after tax years beginning on or after December 31, 2012 will be taxed to such Holder at ordinary income rates.

Distributions to U.S. Holders generally will not be eligible for the dividends received deduction generally allowed to U.S. corporations in respect of dividends received from other U.S. corporations.

A U.S. Holder will be taxed on the U.S. dollar value of any Canadian dollars received as dividends, generally determined at the spot rate as of the date the payment is actually or constructively received. No currency exchange gain or loss will be recognized by a U.S. Holder on such dividend payments if the Canadian dollars are converted into U.S. dollars on the date received at that spot rate. Any gain or loss on a subsequent conversion or other disposition of Canadian dollars generally will be treated as U.S.-source ordinary income or loss.

Taxation of sale, exchange or other taxable disposition of common shares

Upon the sale, exchange or other taxable disposition of a common share, a U.S. Holder generally will recognize gain or loss equal to the difference between the amount realized upon the sale, exchange or other disposition and such U.S. Holder's tax basis in the common share. The amount realized on the sale, exchange or other taxable disposition of the common shares will be the U.S. dollar value of any Canadian dollars received in the transaction, which is determined for cash basis taxpayers on the settlement date for the transaction and for accrual basis taxpayers on the trade date (although accrual basis taxpayers can also elect the settlement date). Any such gain or loss will generally be capital gain or loss and will generally be long-term capital gain or loss if the U.S. Holder's holding period for the common shares transferred exceeds one year on the date of the sale or disposition. Long-term capital gains of non-corporate U.S. Holders derived with respect to the disposition of common shares are currently subject to tax at reduced rates. The deductibility of capital losses is subject to several limitations. Any gain or loss realized on a subsequent conversion or other disposition of Canadian dollars will be ordinary gain or loss.

Disclosure of reportable transactions

If a U.S. Holder sells or disposes of the common shares at a loss or otherwise incurs certain losses that meet certain thresholds, such U.S. Holder may be required to file a disclosure statement with the IRS. For U.S. Holders that are individuals or trusts, there is a special reporting requirement threshold for foreign currency losses, which is US$50,000. Failure to comply with these and other reporting requirements could result in the imposition of significant penalties.

Foreign tax credit limitations

U.S. Holders may be subject to Canadian withholding tax on payments made with respect to the common shares. Subject to certain conditions and limitations, such withholding taxes may be treated as foreign taxes eligible for credit against a U.S. Holder's U.S. federal income tax liability. Such credit may not be available to U.S. holders owning the common shares in a non-taxable account. Additionally, foreign taxes may not be eligible to the extent they could have been reduced pursuant to an income tax treaty.

It is possible that we are, or at some future time will be, at least 50% owned by U.S. persons. Dividends paid by a foreign corporation that is at least 50% owned by U.S. persons may be treated as U.S.-source income (rather than foreign-source income) for foreign tax credit purposes to the extent the foreign corporation has more than an insignificant amount of U.S.-source income. The effect of this rule may be to treat a portion of any dividends we pay as U.S.-source income. Treatment of the dividends as U.S.-source income in whole or in part may limit a U.S. Holder's ability to claim a foreign tax credit for the Canadian withholding taxes payable in respect of the dividends. Subject to certain limitations, the Code permits a U.S. Holder entitled to benefits under the U.S.-Canadian income tax treaty to elect to treat any Company dividends as foreign-source income for foreign tax credit purposes. U.S. Holders should consult their own tax advisors about the desirability of making, and the method of making, such an election.

The rules governing foreign tax credits are complex. U.S. Holders are urged to consult their own tax advisors regarding the availability of foreign tax credits in their particular circumstances.

Passive foreign investment company

A foreign corporation is a passive foreign investment company ("PFIC") within the meaning of Section 1297 of the Code if, during any taxable year, (i) 75% or more of its gross income consists of certain types of passive income, or (ii) the average value (or basis in certain cases) of its passive assets (generally assets that generate passive income) is 50% or more of the average value (or basis in certain cases) of all of its assets. If we were a PFIC while a taxable U.S. Holder held common shares, the PFIC rules could have the effect of subjecting such U.S. Holder to an interest charge on any deferred taxation and taxing gain upon the sale of our common shares as ordinary income. In addition, under recently enacted legislation each U.S. Holder of a PFIC is required to file an annual report containing such information as the U.S. Department of the Treasury may require. The reporting requirements imposed by this new legislation have been suspended until the IRS issues the revised form necessary to report the requisite information, but following the release of such revised form, affected U.S. Holders will have to attach the form for the suspended tax year to their next return to be filed with the IRS. If we were classified as a PFIC in any year with respect to which a U.S. Holder owns common shares, we would continue to be treated as a PFIC with respect to the U.S. Holder in all succeeding years during which the U.S. Holder owns common shares, regardless of whether we continue to meet the tests described above. However, if we ceased to be a PFIC, a U.S. Holder of our common shares could avoid some of the adverse effects of the PFIC regime by making a deemed sale election with respect to our common shares.

We do not believe we are a PFIC, and we do not expect to become a PFIC. If our income or asset composition were to become more passive (including through the acquisition of assets that generate passive income, or minority investments in stock of corporations), we could potentially become a PFIC. Our PFIC status for any taxable year may also depend upon the extent to which our revenue is subject to special PFIC rules with respect to "commodities," an analysis that raises uncertainties in application and interpretation. Additionally, if we were a PFIC and were to form or acquire non-U.S. subsidiaries that are treated as corporations for U.S. tax purposes, such subsidiaries could potentially be PFICs. If we owned a subsidiary that is a PFIC, then taxable U.S. Holders could be adversely affected as a result of their indirect ownership of stock in any subsidiary of ours that is a PFIC.

Information reporting and backup withholding

In general, information reporting requirements will apply to payments with respect to common shares paid to a U.S. Holder other than certain exempt recipients (such as corporations). Backup withholding will apply to such payments if such U.S. Holder fails to provide a taxpayer identification number or certification of other exempt status or fails to comply with the applicable requirements of the backup withholding rules. Any amounts withheld under the backup withholding rules will be allowed as a refund or a credit against such U.S. Holder's U.S. federal income tax liability provided the required information is furnished by such U.S. Holder to the IRS. A U.S. Holder who does not provide a correct taxpayer identification number may be subject to penalties imposed by the IRS.

In addition, for taxable years beginning after March 18, 2010, certain U.S. Holders who are individuals who hold certain foreign financial assets (which may include common shares) are required to report information relating to such assets, subject to certain exceptions. The reporting requirement has been suspended until the IRS issues the form necessary to report the requisite information, but following the release of such form, affected U.S. Holders will have to attach the form for the suspended tax year to their next return to be filed with the IRS. U.S. Holders should consult their own tax advisors regarding the effect, if any, of this legislation on their ownership and disposition of common shares.

Additional Tax on Passive Income

Certain U.S. Holders that are individuals, estates or trusts will be required to pay up to an additional 3.8% tax on, among other things, dividends and capital gains for taxable years beginning after December 31, 2012. Such tax will apply to dividends to and capital gains from the sale or other disposition of our common shares.

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CERTAIN CANADIAN FEDERAL INCOME TAX CONSIDERATIONS

The following is a summary of the principal Canadian federal income tax considerations generally applicable under the Income Tax Act (Canada) and the regulations thereunder (collectively, the "Tax Act") to a holder that acquires our common shares pursuant to the offering and that, for the purposes of the Tax Act and the Canada-United States Income Tax Convention (the "Canadian Treaty"), at all relevant times (a) is a resident of the United States and is not resident, or deemed to be resident, in Canada, (b) holds the common shares as capital property, (c) deals at arm's length with the Company, (d) is not affiliated with the Company, and (e) does not use or hold and is not deemed to use or hold the common shares in connection with a trade or business that the prospective purchaser carries on, or is deemed to carry on, in Canada at any time (a "U.S. Holder"). For the purpose of the Tax Act, related persons (as defined therein) are deemed not to deal at arm's length, and it is a question of fact whether persons not related to each other deal at arm's length. Special rules which are not discussed in this summary may apply to "financial institutions" (as defined in the Tax Act), to a U.S. Holder that is an insurer carrying on an insurance business in Canada and elsewhere and to an "authorized foreign bank" (as defined in the Tax Act) and, accordingly, such persons should consult their own tax advisors.

Limited liability companies ("LLCs") that are not taxed as corporations pursuant to the provisions of the Code do not qualify as resident in the U.S. for purposes of the Canadian Treaty. Under the Canadian Treaty, a resident of the U.S. that is a member of such an LLC and is otherwise eligible for benefits under the Canadian Treaty may generally be entitled to claim benefits under the Canadian Treaty in respect of income, profits or gains derived through the LLC.

The Canadian Treaty includes limitation on benefits rules that restrict the ability of certain persons that are resident in the U.S. for purposes of the Canadian Treaty to claim any or all benefits under the Canadian Treaty. U.S. Holders should consult their own tax advisors with respect to their eligibility for benefits under the Canadian Treaty, having regard to these rules.

This summary is of a general nature only and is based upon the facts set out herein, the provisions of the Tax Act, the Canadian Treaty and the current published administrative policies and assessing practices of the Canada Revenue Agency (the "CRA"), all in effect as of the date hereof. This summary is based on the assumption that the common shares issuable will at all relevant times be listed on the Toronto Stock Exchange. This summary takes into account all specific proposals to amend the Tax Act publicly announced by or on behalf of the Minister of Finance (Canada) prior to the date hereof. There can be no assurance that any such proposals will be implemented in their current form or at all. This summary does not otherwise take into account or anticipate any changes in law or in the administrative policies and assessing practices of the CRA, whether by legislative, governmental or judicial decision or action, and does not take into account provincial, territorial or foreign tax legislation or considerations, which may differ significantly from those discussed herein.

This summary is not exhaustive of all possible Canadian federal tax considerations applicable to an investment in common shares. Moreover, the Canadian tax consequences of acquiring, holding or disposing of common shares will vary depending on the U.S. Holder's particular circumstances. Accordingly, this summary is of a general nature only and is not intended to be, and should not be interpreted as, legal or tax advice to any prospective purchaser and no representation with respect to the tax consequence to any particular U.S. Holder is made. Prospective investors should consult their own tax advisors with respect to the Canadian tax consequences of an investment in common shares based on their particular circumstances.

Prospective investors may also be subject to certain Canadian provincial or territorial tax consequences as a result of acquiring, holding or disposing of common shares. Accordingly, prospective investors are urged to consult with their tax advisors for advice with respect to Canadian provincial or territorial tax consequences of an investment in common shares based on their particular circumstances.

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For purposes of the Tax Act, all amounts relating to the acquisition, holding or disposition of common shares, including income, gain or profit, adjusted cost base and proceeds of disposition, must be converted into Canadian dollars based on the prevailing United States dollar exchange rate at the time such amounts arise in accordance with the detailed rules in the Tax Act.

Dividends on Common Shares

Dividends paid or credited on the common shares, or deemed under the Tax Act to be paid or credited on the common shares, to a U.S. Holder will generally be subject to Canadian withholding tax at the rate of 25%, unless the rate is reduced under the provisions of an applicable tax treaty. Under the Canadian Treaty, the withholding tax rate in respect of a dividend paid to a U.S. Holder that is the beneficial owner of the dividend and entitled to full benefits under the Canadian Treaty, is generally reduced to 15%.

Disposition of Common Shares

A U.S. Holder will not be subject to tax under the Tax Act in respect of any capital gain realized by such U.S. Holder on a disposition of common shares unless the common shares constitute "taxable Canadian property" (as defined in the Tax Act) of the U.S. Holder at the time of disposition and the U.S. Holder is not entitled to relief under an applicable tax treaty. Where the common shares are listed on a designated stock exchange for purposes of the Tax Act (which currently includes both the TSX and the NYSE) at a particular time, the common shares will not constitute taxable Canadian property to a U.S. Holder at such time provided that at any time during the sixty-month period that ends at that time, either: (a) the U.S. Holder, persons with which the U.S. Holder does not deal at arm's length, or the U.S. Holder together with all such persons, have not owned 25% or more of any class or series of shares of the capital stock of the Company; or (b) such common shares did not derive, directly or indirectly, more than 50% of their fair market value from one or any combination of (i) real or immovable property situated in Canada, (ii) "Canadian resource properties" (as defined in the Tax Act), (iii) "timber resource properties" (as defined in the Tax Act), and (iv) options or interests in respect of property described in (i), (ii) and (iii).

In the event that the common shares constitute or are deemed to constitute taxable Canadian property to any U.S. Holder, the Canadian Treaty (or other applicable tax treaty or convention) may exempt the U.S. Holder from tax under the Tax Act in respect of the disposition thereof. U.S. Holders whose common shares may be taxable Canadian property should consult with their own tax advisors for advice having regard to their particular circumstances.

UNDERWRITING

We are offering the common shares described in this prospectus through the underwriters named below. TD Securities Inc. and Morgan Stanley & Co. LLC are the joint book-running managers of this offering and the representatives of the underwriters (the "Representative"). We have entered into an underwriting agreement (the "Underwriting Agreement") with the representatives. Subject to the terms and conditions of the Underwriting Agreement, each of the underwriters has severally agreed to purchase, and we have agreed to sell to the underwriters, the number of common shares listed next to its name in the following table.

Underwriters	Number of shares
TD Securities Inc.	
Morgan Stanley & Co. LLC	
Total	

The Underwriting Agreement provides that the underwriters must buy all of the shares if they buy any of them. However, the underwriters are not required to take or pay for the shares covered by the underwriters' over-allotment option described below.

Our common shares are offered subject to a number of conditions, including:

- receipt and acceptance of our common shares by the underwriters, and
- the underwriters' right to reject orders in whole or in part.

In connection with this offering, certain of the underwriters or securities dealers may distribute prospectuses electronically.

We expect that delivery of the shares will be made against payment therefor on or about the closing date of this offering specified on the cover page of this Prospectus, which is five business days following the date of pricing of the shares (this settlement cycle being referred to as "T+5"). Under Rule 15c6-1 of the Exchange Act, trades in the secondary market generally are required to settle in three business days, unless the parties to any such trade expressly agree otherwise. Accordingly, purchasers who wish to trade their shares on the date of pricing or the next succeeding business day will be required, by virtue of the fact that the shares initially will settle in T+5, to specify an alternate settlement cycle at the time of any such trade to prevent a failed settlement. Purchasers of the shares who wish to trade their shares on the date of pricing or the next succeeding business day should consult their own advisor.

Over-Allotment Option

We have granted the underwriters an option to buy up to an aggregate of additional common shares. The underwriters may exercise this option solely for the purpose of covering over-allotments, if any, made in connection with this offering. The underwriters have 30 days from the date of this prospectus to exercise this option. If the underwriters exercise this option, they will each purchase additional shares approximately in proportion to the amounts specified in the table above.

Commissions and Discounts

Shares sold by the underwriters to the public will initially be offered at the public offering price set forth on the cover of this prospectus. Any shares sold by the underwriters to securities dealers may

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be sold at a discount of up to $ per share from the public offering price. Sales of shares may be made in other jurisdictions by affiliates of the underwriters. If all the shares are not sold at the public offering price, the representatives may change the offering price and the other selling terms. Upon execution of the Underwriting Agreement, the underwriters will be obligated to purchase the shares at the prices and upon the terms stated therein.

The following table shows the per share and total underwriting discounts and commissions we will pay to the underwriters assuming both no exercise and full exercise of the underwriters' option to purchase additional common shares.

	No exercise	Full exercise
Per share	$	$
Total	$	$

We estimate that the total expenses of this offering payable by us, not including the underwriting discounts and commissions, will be approximately $ million.

No Sales of Similar Securities

We and our executive officers and directors have entered into lock-up agreements with the underwriters. Under these agreements, subject to certain exceptions, we and each of these persons may not, without the prior written approval of the Representatives, offer, sell, contract to sell or otherwise dispose of, directly or indirectly, or hedge our common shares or securities convertible into or exchangeable or exercisable for our common shares. These restrictions will be in effect for a period of 90 days after the date of this prospectus. At any time and without public notice, the Representatives may, in their sole discretion, release some or all of the securities from these lock-up agreements.

Indemnification

We have agreed to indemnify the underwriters against certain liabilities, including certain liabilities under the Securities Act. If we are unable to provide this indemnification, we have agreed to contribute to payments the underwriters may be required to make in respect of those liabilities.

NYSE and TSX Stock Market Listings

Our common shares are listed on the NYSE under the symbol "AT" and on the TSX under the symbol "ATP."

Price Stabilizations, Short Positions

In connection with this offering, the underwriters may engage in activities that stabilize, maintain or otherwise affect the price of our common shares, including:

- stabilizing transactions;
- short sales;
- purchases to cover positions created by short sales;
- imposition of penalty bids; and
- syndicate covering transactions.

Stabilizing transactions consist of bids or purchases made for the purpose of preventing or retarding a decline in the market price of our common shares while this offering is in progress. These transactions may also include making short sales of our common shares, which involve the sale by the underwriters of a greater number of common shares than they are required to purchase in this offering, and purchasing common shares on the open market to cover positions created by short sales. Short sales may be "covered short sales," which are short positions in an amount not greater than the underwriters' over-allotment option referred to above, or may be "naked short sales," which are short positions in excess of that amount.

The underwriters may close out any covered short position by either exercising their over-allotment option, in whole or in part, or by purchasing shares in the open market. In making this determination, the underwriters will consider, among other things, the price of shares available for purchase in the open market as compared to the price at which they may purchase shares through the over-allotment option.

Naked short sales are short sales made in excess of the over-allotment option. The underwriters must close out any naked short position by purchasing shares in the open market. A naked short position is more likely to be created if the underwriters are concerned that there may be downward pressure on the price of the common shares in the open market that could adversely affect investors who purchased in this offering.

The underwriters also may impose a penalty bid. This occurs when a particular underwriter repays to the underwriters a portion of the underwriting discount received by it because the representatives have repurchased shares sold by or for the account of that underwriter in stabilizing or short covering transactions.

As a result of these activities, the price of our common shares may be higher than the price that otherwise might exist in the open market. If these activities are commenced, they may be discontinued by the underwriters at any time. The underwriters may carry out these transactions on the NYSE, the TSX, in the over-the-counter market or otherwise.

Affiliations

Certain of the underwriters and their affiliates have in the past provided, are currently providing and may in the future from time to time provide, investment banking and other financing, trading, banking, research, transfer agent and trustee services to us or our subsidiaries, for which they have in the past received, and may currently or in the future receive, customary fees and expenses.

The Representatives have provided and are providing services with respect to the Plan of Arrangement pursuant to which they were and are to be paid customary fees upon the public announcement of the Plan of Arrangement and upon consummation thereof, if completed. We agreed to pay TD Securities Inc. and Morgan Stanley & Co. LLC $1.9 million and $1.0 million, respectively, upon public announcement of the Plan of Arrangement and an additional fee of $5.6 million and $4.0 million, respectively, if the Plan of Arrangement is completed.

In addition, the Representatives have jointly committed to provide to us a $625 million credit facility to fund the cash consideration required under the Plan of Arrangement, for which the Representatives will receive customary compensation.

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NOTICE TO INVESTORS

Notice to Prospective Investors in the European Economic Area

In relation to each Member State of the European Economic Area, or EEA, which has implemented the Prospectus Directive (each, a "Relevant Member State"), with effect from, and including, the date on which the Prospectus Directive is implemented in that Relevant Member State (the "Relevant Implementation Date"), an offer to the public of our securities which are the subject of the offering contemplated by this prospectus may not be made in that Relevant Member State, except that, with effect from, and including, the Relevant Implementation Date, an offer to the public in that Relevant Member State of our securities may be made at any time under the following exemptions under the Prospectus Directive, if they have been implemented in that Relevant Member State:

a) to legal entities which are authorized or regulated to operate in the financial markets, or, if not so authorized or regulated, whose corporate purpose is solely to invest in our securities;

b) to any legal entity which has two or more of: (1) an average of at least 250 employees during the last (or, in Sweden, the last two) financial year(s); (2) a total balance sheet of more than €43,000,000 and (3) an annual net turnover of more than €50,000,000, as shown in its last (or, in Sweden, the last two) annual or consolidated accounts; or

c) to fewer than 100 natural or legal persons (other than qualified investors as defined in the Prospectus Directive) subject to obtaining the prior consent of the representatives for any such offer; or

d) in any other circumstances falling within Article 3(2) of the Prospectus Directive provided that no such offer of our securities shall result in a requirement for the publication by us or any underwriter or agent of a prospectus pursuant to Article 3 of the Prospectus Directive.

As used above, the expression "offered to the public" in relation to any of our securities in any Relevant Member State means the communication in any form and by any means of sufficient information on the terms of the offer and our securities to be offered so as to enable an investor to decide to purchase or subscribe for our securities, as the same may be varied in that Member State by any measure implementing the Prospectus Directive in that Member State and the expression "Prospectus Directive" means Directive 2003/71/EC and includes any relevant implementing measure in each Relevant Member State.

The EEA selling restriction is in addition to any other selling restrictions set out in this prospectus.

Notice to Prospective Investors in the United Kingdom

This prospectus is only being distributed to and is only directed at: (1) persons who are outside the United Kingdom; (2) investment professionals falling within Article 19(5) of the Financial Services and Markets Act 2000 (Financial Promotion) Order 2005 (the "Order"); or (3) high net worth companies, and other persons to whom it may lawfully be communicated, falling within Article 49(2)(a) to (d) of the Order (all such persons falling within (1)-(3) together being referred to as "relevant persons"). The shares are only available to, and any invitation, offer or agreement to subscribe, purchase or otherwise acquire such shares will be engaged in only with, relevant persons. Any person who is not a relevant person should not act or rely on this prospectus or any of its contents.

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Notice to Prospective Investors in Switzerland

The Prospectus does not constitute an issue prospectus pursuant to Article 652a or Article 1156 of the Swiss Code of Obligations ("CO") and the shares will not be listed on the SIX Swiss Exchange. Therefore, the Prospectus may not comply with the disclosure standards of the CO and/or the listing rules (including any prospectus schemes) of the SIX Swiss Exchange. Accordingly, the shares may not be offered to the public in or from Switzerland, but only to a selected and limited circle of investors, which do not subscribe to the shares with a view to distribution.

Notice to Prospective Investors in Australia

This prospectus is not a formal disclosure document and has not been, nor will be, lodged with the Australian Securities and Investments Commission. It does not purport to contain all information that an investor or their professional advisers would expect to find in a prospectus or other disclosure document (as defined in the Corporations Act 2001 (Australia)) for the purposes of Part 6D.2 of the Corporations Act 2001 (Australia) or in a product disclosure statement for the purposes of Part 7.9 of the Corporations Act 2001 (Australia), in either case, in relation to the securities.

The securities are not being offered in Australia to "retail clients" as defined in sections 761G and 761GA of the Corporations Act 2001 (Australia). This offering is being made in Australia solely to "wholesale clients" for the purposes of section 761G of the Corporations Act 2001 (Australia) and, as such, no prospectus, product disclosure statement or other disclosure document in relation to the securities has been, or will be, prepared.

This prospectus does not constitute an offer in Australia other than to wholesale clients. By submitting an application for our securities, you represent and warrant to us that you are a wholesale client for the purposes of section 761G of the Corporations Act 2001 (Australia). If any recipient of this prospectus is not a wholesale client, no offer of, or invitation to apply for, our securities shall be deemed to be made to such recipient and no applications for our securities will be accepted from such recipient. Any offer to a recipient in Australia, and any agreement arising from acceptance of such offer, is personal and may only be accepted by the recipient. In addition, by applying for our securities you undertake to us that, for a period of 12 months from the date of issue of the securities, you will not transfer any interest in the securities to any person in Australia other than to a wholesale client.

Notice to Prospective Investors in Hong Kong

Our securities may not be offered or sold in Hong Kong, by means of this prospectus or any document other than (i) to "professional investors" within the meaning of the Securities and Futures Ordinance (Cap.571, Laws of Hong Kong) and any rules made thereunder, or (ii) in circumstances which do not constitute an offer to the public within the meaning of the Companies Ordinance (Cap.32, Laws of Hong Kong), or (iii) in other circumstances which do not result in the document being a "prospectus" within the meaning of the Companies Ordinance (Cap.32, Laws of Hong Kong). No advertisement, invitation or document relating to our securities may be issued or may be in the possession of any person for the purpose of issue (in each case whether in Hong Kong or elsewhere) which is directed at, or the contents of which are likely to be accessed or read by, the public in Hong Kong (except if permitted to do so under the securities laws of Hong Kong) other than with respect to the securities which are or are intended to be disposed of only to persons outside Hong Kong or only to "professional investors" within the meaning of the Securities and Futures Ordinance (Cap. 571, Laws of Hong Kong) and any rules made thereunder.

Notice to Prospective Investors in Japan

Our securities have not been and will not be registered under the Financial Instruments and Exchange Law of Japan (the Financial Instruments and Exchange Law) and our securities will not be offered or sold, directly or indirectly, in Japan, or to, or for the benefit of, any resident of Japan (which term as used herein means any person resident in Japan, including any corporation or other entity organized under the laws of Japan), or to others for re-offering or resale, directly or indirectly, in Japan, or to a resident of Japan, except pursuant to an exemption from the registration requirements of, and otherwise in compliance with, the Financial Instruments and Exchange Law and any other applicable laws, regulations and ministerial guidelines of Japan.

Notice to Prospective Investors in Singapore

This document has not been registered as a prospectus with the Monetary Authority of Singapore and in Singapore, the offer and sale of our securities is made pursuant to exemptions provided in sections 274 and 275 of the Securities and Futures Act, Chapter 289 of Singapore ("SFA"). Accordingly, this prospectus and any other document or material in connection with the offer or sale, or invitation for subscription or purchase, of our securities may not be circulated or distributed, nor may our securities be offered or sold, or be made the subject of an invitation for subscription or purchase, whether directly or indirectly, to persons in Singapore other than (i) to an institutional investor as defined in Section 4A of the SFA pursuant to Section 274 of the SFA, (ii) to a relevant person as defined in section 275(2) of the SFA pursuant to Section 275(1) of the SFA, or any person pursuant to Section 275(1A) of the SFA, and in accordance with the conditions specified in Section 275 of the SFA or (iii) otherwise pursuant to, and in accordance with the conditions of, any other applicable provision of the SFA, in each case subject to compliance with the conditions (if any) set forth in the SFA. Moreover, this document is not a prospectus as defined in the SFA. Accordingly, statutory liability under the SFA in relation to the content of prospectuses would not apply. Prospective investors in Singapore should consider carefully whether an investment in our securities is suitable for them.

Where our securities are subscribed or purchased under Section 275 of the SFA by a relevant person which is:

(a) by a corporation (which is not an accredited investor as defined in Section 4A of the SFA) the sole business of which is to hold investments and the entire share capital of which is owned by one or more individuals, each of whom is an accredited investor; or

(b) for a trust (where the trustee is not an accredited investor) whose sole purpose is to hold investments and each beneficiary of the trust is an individual who is an accredited investor, shares of that corporation or the beneficiaries' rights and interest (howsoever described) in that trust shall not be transferable for six months after that corporation or that trust has acquired the shares under Section 275 of the SFA, except:

    (i) to an institutional investor (for corporations under Section 274 of the SFA) or to a relevant person defined in Section 275(2) of the SFA, or any person pursuant to an offer that is made on terms that such shares of that corporation or such rights and interest in that trust are acquired at a consideration of not less than S$200,000 (or its equivalent in a foreign currency) for each transaction, whether such amount is to be paid for in cash or by exchange of securities or other assets, and further for corporations, in accordance with the conditions, specified in Section 275 of the SFA;

    (ii) where no consideration is given for the transfer; or

    (iii) where the transfer is by operation of law.

In addition, investors in Singapore should note that the securities acquired by them are subject to resale and transfer restrictions specified under Section 276 of the SFA, and they, therefore, should seek their own legal advice before effecting any resale or transfer of their securities.

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LEGAL MATTERS

Certain legal matters relating to the issue and sale of the common shares offered hereby will be passed upon by Goodmans on behalf of Atlantic Power and by Blake, Cassels & Graydon LLP on behalf of the underwriters. Goodwin Procter LLP is acting as U.S. counsel to Atlantic Power in this offering and Paul, Weiss, Rifkind, Wharton & Garrison LLP is acting as U.S. counsel for the underwriters.

EXPERTS

The consolidated financial statements and financial statement schedule of Atlantic Power as of December 31, 2010 and 2009 and for each of the years in the three-year period ended December 31, 2010 appearing in Atlantic Power's Annual Report on Form 10-K (including the schedule appearing therein) have been incorporated by reference herein in reliance upon the reports of the United States and Canadian firms of KPMG LLP, independent registered public accounting firms, incorporated by reference herein, and upon the authority of said firms as experts in accounting and auditing.

The financial statements of Chambers Cogeneration Limited Partnership as of December 31, 2010, and for the year then ended incorporated in this registration statement by reference to Atlantic Power's Annual Report on Form 10-K for the year ended December 31, 2010, have been so incorporated in reliance on the report of PricewaterhouseCoopers LLP, independent auditors, given on the authority of said firm as experts in auditing and accounting.

The consolidated financial statements of CPILP as of December 31, 2010 and 2009 and for each of the years in the three year period ended December 31, 2010 have been included in this registration statement in reliance on the report of the Canadian firm of KPMG LLP, an independent registered public accounting firm, and upon the authority of said firm as experts in auditing and accounting.

WHERE YOU CAN FIND MORE INFORMATION

We have filed with the SEC a registration statement under the Securities Act that registers the offer and sale of the securities offered by this prospectus. This prospectus is part of the registration statement, but the registration statement, including the accompanying exhibits included or incorporated by reference therein, contains additional relevant information about us.

We are required to file annual, quarterly and current reports, proxy statements and other information with the SEC. You may read and copy any document we file, including the registration statement containing this prospectus and the registration statement with respect to the registration of the common shares, at the SEC's Public Reference Room at 100 F Street, N.E., Washington, D.C. 20549. You may call the SEC at 1-800-SEC-0330 for further information on the operation of the Public Reference Room. Our SEC filings are also available to the public from the SEC's website at *http://www.sec.gov* and on our website at *http://www.atlanticpower.com*. We have included the SEC's web address and our web address as inactive textual references only. 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.

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INCORPORATION BY REFERENCE OF CERTAIN DOCUMENTS

We are "incorporating by reference" into this prospectus certain information we file with the SEC, which means that we are disclosing important information to you by referring you to those documents. The documents that we incorporate disclose important information that each prospective purchaser should consider when deciding whether to invest in the common shares. We incorporate the documents listed below:

- our Annual Report on Form 10-K for the year ended December 31, 2010, filed with the SEC on March 18, 2011;

- our Quarterly Reports on Form 10-Q for the quarters ended March 31, 2011 and June 30, 2011, respectively, filed with the SEC on May 11, 2011 and August 12, 2011, respectively;

- our annual Proxy Statement on Schedule 14A relating to our annual meeting of shareholders, filed with the SEC on May 2, 2011 (with respect to those portions incorporated by reference into our 2010 Annual Report on Form 10-K); and

- our Current Reports on Form 8-K filed with the SEC on May 4, 2011, June 16, 2011, June 20, 2011, June 24, 2011, July 15, 2011 and August 2, 2011 (as amended by our Current Report on Form 8-K/A filed on August 5, 2011), except, in any such cases, the portions furnished and not filed pursuant to Item 7.01 or otherwise.

You may request a copy of these filings, and any exhibits we have specifically incorporated by reference as an exhibit in this prospectus, at no cost by writing or telephoning us at the following: Atlantic Power Corporation, 200 Clarendon Street, Floor 25, Boston, Massachusetts 02116. Our telephone number is (617) 977-2400.

INDEX TO CONSOLIDATED FINANCIAL STATEMENTS OF CPILP

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KPMG LLP	Telephone	(780) 429-7300
Chartered Accountants	Fax	(780) 429-7379
10125 - 102 Street	Internet	www.kpmg.ca
Edmonton AB T5J 3V8		
Canada		

INDEPENDENT AUDITORS' REPORT

To the Partners of Capital Power Income L.P.

We have audited the accompanying consolidated balance sheets of Capital Power Income L.P. and subsidiaries ("the Partnership") as of December 31, 2010, 2009, and 2008 and the related consolidated statements of income and loss, partners' equity, comprehensive loss and cash flows for each year in the three-year period ended December 31, 2010. These consolidated financial statements are the responsibility of the Partnership's management. Our responsibility is to express an opinion on these consolidated financial statements based on our audits.

We conducted our audits in accordance with auditing standards generally accepted in the United States of America. Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. An audit includes consideration of internal control over financial reporting as a basis for designing audit procedures that are appropriate in the circumstances, but not for the purpose of expressing an opinion on the effectiveness of the Partnership's internal control over financial reporting. Accordingly, we express no such opinion. An audit also includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements. An audit also includes assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

In our opinion, the consolidated financial statements referred to above present fairly, in all material respects, the financial position of the Partnership as of December 31, 2010, 2009, and 2008 and the results of their operations and their cash flows for each of the years in the three-year period ended December 31, 2010 in conformity with Canadian generally accepted accounting principles.

Accounting principles generally accepted in Canada vary in certain significant respects from U.S. generally accepted accounting principles. Information relating to the nature and effect of such differences is presented in note 27 to the consolidated financial statements.

"signed KPMG"

KPMG LLP
Edmonton, Canada

March 2, 2011, except as to notes 27 and 28, which are as of July 25, 2011

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Capital Power Income L.P.

CONSOLIDATED STATEMENTS OF INCOME AND LOSS

	Years ended December 31		
	2010	**2009**	**2008**
	(In millions of dollars except units and per unit amounts)		
Revenues	**$ 532.4**	$ 586.5	$ 499.3
Cost of fuel	**230.7**	271.4	288.8
Operating and maintenance expense	**114.2**	103.4	99.1
	187.5	211.7	111.4
Other costs			
Depreciation, amortization and accretion (Note 5)	**98.3**	93.3	88.3
Financial charges and other, net (Note 9)	**40.1**	46.4	70.7
Management and administration	**13.9**	15.2	20.2
Asset impairment charge (Note 8)			24.1
	152.3	154.9	203.3
Net income (loss) from continuing operations before income tax and preferred share dividends	**35.2**	56.8	(91.9)
Income tax recovery (Note 14)	**9.4**	8.9	31.4
Net income (loss) from continuing operations before preferred share dividends	**44.6**	65.7	(60.5)
Preferred share dividends of a subsidiary company (Note 11)	**14.1**	7.9	6.6
Net income (loss) from continuing operations	**30.5**	57.8	(67.1)
Loss from discontinued operations (Note 25)		(0.2)	(0.7)
Net income (loss)	**$ 30.5**	$ 57.6	$ (67.8)
Net income (loss) per unit from continuing operations	**$ 0.55**	$ 1.07	$ (1.24)
Net loss per unit from discontinued operations			(0.01)
Net income (loss) per unit	**$ 0.55**	$ 1.07	$ (1.26)
Weighted average units outstanding (millions)	**55.0**	53.9	53.9

See accompanying notes to the consolidated financial statements.

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Capital Power Income L.P.

CONSOLIDATED STATEMENTS OF CASH FLOW

	Years ended December 31		
	2010	**2009**	**2008**
	(In millions of dollars)		
Operating activities			
Net income (loss) from continuing operations	**$ 30.5**	$ 57.8	$ (67.1)
Items not affecting cash:			
Depreciation, amortization and accretion	**98.3**	93.3	88.3
Asset impairment charge			24.1
Future income tax recovery	**(13.9)**	(12.4)	(34.4)
Fair value changes on derivative instruments	**3.6**	(6.2)	98.4
Unrealized foreign exchange losses		0.3	26.2
Other	**6.6**	10.0	8.7
	125.1	142.8	144.2
Change in non-cash working capital (Note 16)	**(7.3)**	(8.3)	13.3
Cash provided by operating activities of continuing operations	**117.8**	134.5	157.5
Cash (used in) provided by operating activities of discontinued operations		(2.8)	2.7
Cash provided by operating activities	**117.8**	131.7	160.2
Investing activities			
Additions to property, plant and equipment and other assets	**(28.3)**	(100.7)	(40.0)
Change in non-cash working capital	**(7.2)**	4.2	2.7
Dividends from equity investment		1.3	3.2
Acquisition of Morris Cogeneration LLC (Note 24)			(90.7)
Acquisition of equity investment		(8.8)	
Cash used in investing activities of continuing operations	**(35.5)**	(104.0)	(124.8)
Cash provided by (used in) investing activities of discontinued operations		11.6	(3.5)
Cash used in investing activities	**(35.5)**	(92.4)	(128.3)
Financing activities			
Distributions paid	**(69.5)**	(127.7)	(135.8)
Net borrowings under credit facilities	**8.1**	1.8	85.7
Proceeds from preferred share offering (Note 11)		100.0	
Long-term debt repaid	**(1.4)**	(1.3)	(1.1)
Issue costs	**(0.5)**	(4.1)	
Cash used in financing activities	**(63.3)**	(31.3)	(51.2)
Foreign exchange gains (losses) on cash held in a foreign currency	**(1.0)**	(1.5)	2.2
Increase (decrease) in cash and cash equivalents	**18.0**	6.5	(17.1)
Cash and cash equivalents, beginning of year	**9.5**	3.0	20.1
Cash and cash equivalents, end of year	**$ 27.5**	$ 9.5	$ 3.0
Supplementary cash flow information			
Income taxes paid	**$ 5.6**	$ 2.4	$ 6.7
Interest paid	**$ 38.0**	$ 43.6	$ 37.1

See accompanying notes to the consolidated financial statements.

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Capital Power Income L.P.

CONSOLIDATED BALANCE SHEETS

	As at December 31		
	2010	**2009**	**2008**
	(In millions of dollars)		
ASSETS			
Current assets			
Cash and cash equivalents	**$ 27.5**	$ 9.5	$ 3.0
Accounts receivable	**52.5**	51.8	60.6
Inventories (Note 4)	**19.5**	24.6	23.2
Prepaids and other	**4.0**	4.5	5.0
Derivative assets (Note 15)	**10.4**	7.8	22.8
Future income taxes (Note 14)	**7.1**	1.9	2.3
Current assets of discontinued operations			2.3
	121.0	100.1	119.2
Property, plant and equipment (Note 5)	**994.1**	1,064.7	1,106.0
Power purchase arrangements (Note 6)	**290.0**	330.4	408.6
Goodwill (Note 7)	**45.0**	47.6	55.1
Derivative assets (Note 15)	**29.7**	31.8	27.1
Future income taxes (Note 14)	**41.2**	35.0	16.8
Other assets (Note 8)	**62.8**	58.5	64.4
Long-term assets of discontinued operations (Note 25)			12.0
	$ 1,583.8	$ 1,668.1	$ 1,809.2
LIABILITIES AND PARTNERS' EQUITY			
Current liabilities			
Accounts payable	**$ 52.9**	$ 59.6	$ 70.3
Distributions payable	**8.2**	7.9	33.9
Long-term debt due within one year (Note 9)		1.4	1.3
Derivative liabilities (Note 15)	**21.1**	2.9	13.0
Current liabilities of discontinued operations			1.2
Future income taxes (Note 14)		3.8	
	82.2	75.6	119.7
Long-term debt (Note 9)	**704.5**	719.4	798.5
Derivative liabilities (Note 15)	**81.9**	36.4	38.5
Other liabilities (Note 10)	**37.1**	34.8	33.3
Long-term liabilities of discontinued operations (Note 25)			4.2
Future income taxes (Note 14)	**50.7**	62.7	60.7
Preferred shares issued by a subsidiary company (Note 11)	**219.7**	219.7	122.0
Partners' equity	**407.7**	519.5	632.3
Commitments (Note 23)			
Subsequent event (Note 28)			
	$ 1,583.8	$ 1,668.1	$ 1,809.2

Approved by CPI Income Services Ltd., as General Partner of Capital Power Income L.P.

"signed Brian Vaasjo"	*"signed Brian Felesky"*
Brian T. Vaasjo	**Brian A. Felesky**
Director and Chairman of the Board	Director and Chairman of the Audit Committee

See accompanying notes to the consolidated financial statements.

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Capital Power Income L.P.

CONSOLIDATED STATEMENTS OF PARTNERS' EQUITY

	Years ended December 31		
	2010	**2009**	**2008**
	(In millions of dollars)		
Partnership capital (Note 12)			
Balance, beginning of year	**$ 1,200.6**	$ 1,197.1	$ 1,197.1
Partnership units issued pursuant to distribution reinvestment plan	**27.0**	3.5	
Balance, end of year	**$ 1,227.6**	$ 1,200.6	$ 1,197.1
Deficit			
Balance, beginning of year:	**(543.7)**	(496.1)	(296.5)
Net income (loss)	**30.5**	57.6	(67.8)
Distributions	**(96.9)**	(105.2)	(135.8)
Balance, end of year	**$ (610.1)**	$ (543.7)	$ (500.1)
Accumulated other comprehensive loss (Note 13)			
Balance, beginning of year	**$ (137.4)**	$ (64.7)	$ 5.1
Other comprehensive loss	**(72.4)**	(72.7)	(69.8)
Balance, end of year	**$ (209.8)**	$ (137.4)	$ (64.7)
Total of deficit and accumulated other comprehensive loss	**$ (819.9)**	$ (681.1)	$ (564.8)
Partners' equity	**$ 407.7**	$ 519.5	$ 632.3

See accompanying notes to the consolidated financial statements.

Capital Power Income L.P.

CONSOLIDATED STATEMENTS OF COMPREHENSIVE LOSS

	Years ended December 31		
	2010	**2009**	**2008**
	(In millions of dollars)		
Net income (loss)	**$ 30.5**	$ 57.6	$ (67.8)
Other comprehensive income (loss), net of income taxes			
Losses on translating net assets of self-sustaining foreign operations[1]	**(27.4)**	(65.9)	(66.0)
Amortization of deferred gains on derivative instruments de-designated as cash flow hedges to income[2]	**(0.5)**	(0.4)	(3.8)
Unrealized losses on derivative instruments designated as cash flow hedges[3]	**(46.7)**	(6.7)	
Ineffective portion of cash flow hedges reclassified to net income[2]	**2.2**	0.3	
	(72.4)	(72.7)	(69.8)
Comprehensive loss	**$ (41.9)**	$ (15.1)	$ (137.6)

(1) Includes income tax expense of $0.6 million (2009 and 2008 $nil).

(2) Net of income tax of $nil.

(3) Net of income tax of $14.6 million (2009 $2.5 million; 2008 $nil).

See accompanying notes to the consolidated financial statements.

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Capital Power Income L.P.

Notes to the Consolidated Financial Statements

Note 1. Description of the Partnership

Capital Power Income L.P. (the Partnership) is a limited partnership created under the laws of the Province of Ontario pursuant to a Partnership Agreement dated March 27, 1997, as amended and restated November 4, 2009. The Partnership commenced operations on June 18, 1997 and currently has independent power generating facilities in British Columbia, Ontario, California, Colorado, Illinois, New Jersey, New York, North Carolina and Washington State.

CPI Income Services Ltd., the general partner of the Partnership (the General Partner), has the responsibility for overseeing the management of the Partnership and distributions to unitholders. The General Partner is a wholly owned subsidiary of CPI Investments Inc. (Investments). Capital Power Corporation (collectively with its subsidiaries, CPC, unless otherwise indicated) indirectly owns all of the 49 voting, participating shares of Investments and EPCOR Utilities Inc. (EPCOR) indirectly owns all of the 51 voting, non-participating shares of Investments. The General Partner has engaged certain other subsidiaries of CPC (collectively herein, the Manager) to perform management and administrative services on behalf of the Partnership and to operate and maintain the power plants pursuant to management and operations agreements.

Note 2. Significant accounting policies

Basis of presentation

The consolidated financial statements of the Partnership have been prepared by the management of the General Partner in accordance with Canadian generally accepted accounting principles (GAAP) and include the accounts of the Partnership and of its subsidiaries. All significant intercompany transactions and balances have been eliminated.

Measurement uncertainty

The preparation of the Partnership's financial statements in accordance with GAAP requires management to make estimates that affect the reported amounts of revenues, expenses, assets and liabilities as well as the disclosure of contingent assets and liabilities at the financial statement date. The Partnership uses the most current information available and exercises careful judgment in making these estimates and assumptions.

For determining asset impairments, recording financial assets and liabilities and for certain disclosures, the Partnership is required to estimate the fair value of certain assets or obligations. Estimates of fair value may be based on readily determinable market values, depreciated replacement cost or discounted cash flow techniques employing estimated future cash flows based on a number of assumptions and using an appropriate discount rate.

Adjustments to previous estimates, which may be material, will be recorded in the period they become known.

Revenue recognition

Power purchase arrangements, steam purchase arrangements and energy services agreements (collectively referred to as power purchase arrangements or PPAs) are long-term contracts to sell power and steam from the Partnership on a predetermined basis. As explained in "Power purchase arrangements containing a lease," PPAs may be classified as a lease (either operating or capital) and the income is recognized in revenue according to lease revenue recognition standards. For those PPAs

Capital Power Income L.P.

Notes to the Consolidated Financial Statements (Continued)

Note 2. Significant accounting policies (Continued)

that are not considered to contain a lease, income earned on the PPA is recognized in revenue as follows: Revenue from the sales of electricity, steam and natural gas are recognized on delivery or availability for delivery under take or pay contracts. Revenue from certain long-term contracts with fixed payments is recognized at the lower of (1) the megawatt hours (MWhs) made available during the period multiplied by the billable contract price per MWh and (2) an amount determined by the MWhs made available during the period multiplied by the average price per MWh over the term of the contract from the date of acquisition. Any excess of the current period contract price over the average price is recorded as deferred revenue.

Gains and losses on non-financial derivative instruments settlements are recorded in revenues or cost of fuel, as appropriate.

Financial instruments

Financial assets are identified and classified as either available for sale, held for trading, held to maturity or loans and receivables. Financial liabilities are classified as either held for trading or other liabilities. Initially, all financial assets and financial liabilities are recorded on the balance sheet at fair value with subsequent measurement determined by the classification of each financial asset and liability.

Financial assets and financial liabilities held for trading are measured at fair value with the changes in fair value reported in net income. Financial assets held to maturity, loans and receivables and financial liabilities other than those held for trading are measured at amortized cost. Available for sale financial assets are measured at fair value with changes in fair value reported in other comprehensive income until the financial asset is disposed of or becomes impaired. Investments in equity instruments classified as available for sale that do not have quoted market prices in an active market are measured at cost.

Upon initial recognition, the Partnership may designate financial instruments as held for trading when such financial instruments have a reliably determinable fair value and where doing so eliminates or significantly reduces a measurement or recognition inconsistency that would otherwise arise from measuring assets and liabilities or recognising gains and losses on them on a different basis. The Partnership has designated its cash and cash equivalents as held for trading. All other non-derivative financial assets not meeting the Partnership's criteria for designation as held for trading are classified as available for sale, loans and receivables or held to maturity.

Financial assets purchased or sold, where the contract requires the asset to be delivered within an established timeframe, are recognized on a settlement date basis.

Transaction costs on financial assets and liabilities classified as other than held for trading are capitalized and amortized over the expected life of the instrument, based on contractual cash flows, using the effective interest method (EIM). The EIM calculates the amortized cost of a financial asset or liability and allocates the interest income or expense over the term of the financial asset or liability using an effective interest rate.

Derivative instruments and hedging activities

To reduce its exposure to movements in energy commodity prices, interest rate changes and foreign currency exchange rates, the Partnership uses various risk management techniques including the

Capital Power Income L.P.

Notes to the Consolidated Financial Statements (Continued)

Note 2. Significant accounting policies (Continued)

use of derivative instruments. Derivative instruments may include forward contracts, fixed-for-floating swaps and option contracts. Such instruments are used to establish a fixed price for an energy commodity, a cash flow denominated in a foreign currency or an interest-bearing obligation. All derivative instruments, including embedded derivatives, are recorded at fair value on the balance sheet as derivative instruments assets or derivative instruments liabilities except for embedded derivatives instruments that are clearly and closely linked to their host contract and the combined instrument is not measured at fair value. Any contract to buy or sell a commodity that was entered into and continues to be held for the purpose of the receipt or delivery of that commodity in accordance with the Partnership's expected purchase, sale or usage requirements is not treated as a derivative. All changes in the fair value of derivatives are recorded in net income unless cash flow hedge accounting is used, in which case changes in fair value of the effective portion of the derivatives are recorded in other comprehensive income.

The Partnership uses non-financial forward delivery contracts and financial contracts-for-differences to manage the Partnership's exposure to fluctuations in natural gas prices related to obligations arising from its natural gas fired generation facilities. Under the non-financial forward delivery contracts, the Partnership agrees to purchase natural gas at a fixed price for delivery of a pre-determined quantity under a specified timeframe. Under the financial contracts-for-differences derivatives, the Partnership agrees to exchange, with creditworthy or adequately secured counterparties, the difference between the variable or indexed price and the fixed price on a notional quantity of the underlying commodity for a specified timeframe.

Foreign exchange forward contracts are used by the Partnership to manage foreign exchange exposures, consisting mainly of U.S. dollar exposures, resulting from anticipated transactions denominated in foreign currencies.

The Partnership may use forward interest rate or swap agreements and option agreements to manage the impact of fluctuating interest rates on existing debt.

The Partnership may use hedge accounting when there is a high degree of correlation between the risk in the item designated as being hedged (the hedged item) and the derivative instrument designated as a hedge (the hedging instrument). The Partnership documents all relationships between hedging instruments and hedged items at the hedge's inception, including its risk management objectives and its assessment of the effectiveness of the hedging relationship on a retrospective and prospective basis. The Partnership uses cash flow hedges for certain of its anticipated transactions to reduce exposure to fluctuations in changes in natural gas prices. In a cash flow hedging relationship, the effective portion of the change in the fair value of the hedging derivative is recognized in other comprehensive income, while the ineffective portion is recognized in net income. The amounts recognized in accumulated other comprehensive income are reclassified into net income in the same period or periods in which the hedged item occurs and is recorded in net income or when the hedged item becomes probable of not occurring. The hedging relationship for the natural gas contracts, which are derivative instruments, was established after the inception of the contracts. The fair value of these contracts at the date of hedge designation is recognized in net income as the natural gas is delivered under the contracts based on the anticipated fair value of the deliveries at the inception of the hedging relationship.

A hedging relationship is discontinued if the hedging relationship ceases to be effective, if the hedged item is an anticipated transaction and it is probable that the transaction will not occur by the

Capital Power Income L.P.

Notes to the Consolidated Financial Statements (Continued)

Note 2. Significant accounting policies (Continued)

end of the originally specified time period, if the Partnership terminates its designation of the hedging relationship or if either the hedged or hedging instrument ceases to exist as a result of its maturity, expiry, sale, termination or cancellation and is not replaced as part of the Partnership's hedging strategy.

If a cash flow hedging relationship is discontinued or ceases to be effective, any cumulative gains or losses arising prior to such time are deferred in accumulated other comprehensive income and recognized in net income in the same period as the hedged item, and subsequent changes in the fair value of the derivative instrument are reflected in net income. If the hedged or hedging item matures, expires, or is sold, extinguished or terminated and the hedging item is not replaced, any gains or losses associated with the hedging item that were previously recognized in other comprehensive income are recognized in net income in the same period as the corresponding gains or losses on the hedged item. When it is no longer probable that an anticipated transaction will occur within the originally determined period and the associated cash flow hedge has been discontinued, any gains or losses associated with the hedging item that were previously recognized in other comprehensive income are recognized in net income in the period.

When the conditions for hedge accounting cannot be applied, the changes in fair value of the derivative instruments are recognized as described above. The fair value of derivative financial instruments reflects changes in the commodity market prices and foreign exchange rates. Fair value is determined based on exchange or over-the-counter price quotations by reference to bid or asking price as appropriate, in active markets. In illiquid or inactive markets, the Partnership uses appropriate valuation and price modeling techniques commonly used by market participants to estimate fair value. Fair values determined using valuation models require the use of assumptions concerning the amounts and timing of future cash flows. Fair value amounts reflect management's best estimates using external readily observable market data such as future prices, interest rate yield curves, foreign exchange rates, discount rates for time value and volatility where available. It is possible that the assumptions used in establishing fair value amounts will differ from future outcomes and the impact of such variations could be material.

Income taxes

Future income tax assets and liabilities are determined based on temporary differences between the tax basis of assets and liabilities and their carrying amounts for accounting purposes. Future income tax assets and liabilities are measured using the tax rate that is expected to apply when the temporary differences reverse.

The Partnership was not subject to Canadian income taxes and accordingly those taxes which are the responsibility of individual partners have not been reflected in these consolidated financial statements. Certain subsidiaries are taxable and applicable income, withholding and other taxes have been reflected in these consolidated financial statements. However, the Partnership is subject to Canadian income taxes after 2010. As a result, the Partnership recognized future income taxes based on the estimated net taxable timing differences which are expected to reverse after 2010.

Cash and cash equivalents

Cash and cash equivalents include cash or highly liquid, investment-grade, short-term investments and are recorded at fair value.

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Capital Power Income L.P.

Notes to the Consolidated Financial Statements (Continued)

Note 2. Significant accounting policies (Continued)

Inventories

Inventories represent small parts and other consumables and fuel, the majority of which is consumed by the Partnership in provision of its goods and services, and are valued at the lower of cost and net realizable value. Cost includes the purchase price, transportation costs and other costs to bring the inventories to their present location and condition. The cost of inventory items that are interchangeable are determined on an average cost basis. For inventory items that are not interchangeable, cost is assigned using specific identification of their individual costs. Previous write downs of inventories from cost to net realizable value can be fully or partially reversed if supported by economic circumstances.

Property, plant and equipment

Property, plant and equipment is recorded at cost. Power generation plant and equipment, less estimated residual value, is depreciated on a straight-line basis over estimated service lives of one to fifty years. Other equipment, which includes the costs of office furniture, tools and vehicles, is capitalized and depreciated over estimated service lives of three to fifteen years.

Property, plant and equipment, including asset retirement costs, is periodically reviewed for impairment whenever events or changes in circumstances indicate that the carrying amount may not be recoverable from estimated undiscounted future cash flows. If it is determined that the estimated net recoverable amount is less than the net carrying amount, a write-down to the asset's fair value is recognized during the period, with a charge to income.

Power purchase arrangements

On acquisition of power plants with existing PPAs in place, the acquired PPAs are capitalized as an intangible asset and included within the balance sheet as PPAs. The Partnership records acquired PPAs at their fair value and amortizes them over the remaining terms of the contracts.

Power purchase arrangements containing a lease

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

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

Payments received under PPAs classified as direct financing leases are segmented into those for the lease and those for other elements on the basis of their relative fair value.

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Capital Power Income L.P.

Notes to the Consolidated Financial Statements (Continued)

Note 2. Significant accounting policies (Continued)

Long-term investments

Investments that are not controlled by the Partnership, but over which it has significant influence are accounted for using the equity method and recorded at original cost and adjusted periodically to recognize the Partnership's proportionate share of the investee's net income or losses after the date of investment, additional contributions made and dividends received. Other investments are stated at cost. When there has been a decline in value that is other than temporary, the carrying amount of an investment is reduced to its fair value.

Investment in joint venture

The investment in a joint venture is accounted for using the proportionate consolidation method. Under this method, the Partnership records its proportionate share of assets, liabilities, revenue and expenses of the joint venture.

Goodwill

Goodwill is the residual amount that results when the purchase price of an acquired business exceeds the sum of the amounts allocated to the net assets acquired based on their fair values. Goodwill is not amortized, but rather is tested for impairment at least annually or more frequently if events and circumstances indicate that a possible impairment may exist. To test for impairment, the fair value of the reporting unit to which the goodwill relates is compared to the carrying amount, including goodwill, of the reporting unit. If the carrying amount of the reporting unit exceeds its fair value, the fair value of the reporting unit's goodwill is compared with its carrying amount to measure the impairment loss, if any. The Partnership determines the fair value of a reporting unit using discounted cash flow techniques and estimated future cash flows.

Other intangible assets

Other intangible assets consist primarily of emissions allowances and are amortized over their remaining lives.

Asset retirement obligations

The Partnership recognizes asset retirement obligations for its power plants. The fair value of the liability is added to the carrying amount of the associated plant asset and depreciated accordingly. The liability is accreted at the end of each period through charges to depreciation, amortization and accretion. The Partnership has recorded these asset retirement obligations, as it is legally required to remove the facilities at the end of their useful lives and restore the plant sites to their original condition.

Foreign currency translation

The Partnership's functional and presentation currency is the Canadian dollar. The Partnership indirectly owns U.S. subsidiaries which are self-sustaining foreign operations translated to Canadian dollars using the current rate method. Assets and liabilities are translated at the exchange rate in effect at the balance sheet date. Revenues and expenses are translated at average exchange rates prevailing during the period. The resulting translation gains and losses are deferred and included in accumulated

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Capital Power Income L.P.

Notes to the Consolidated Financial Statements (Continued)

Note 2. Significant accounting policies (Continued)

other comprehensive income until there is a reduction in the Partnership's net investment in the foreign operations. Prior to October 1, 2008, the U.S. subsidiaries were considered integrated foreign operations.

Net income per unit

Net income per unit is calculated by dividing net income by the weighted average number of units outstanding, including those held by CPC.

Note 3. Changes in accounting policies

Future accounting changes

International financial reporting standards

The CICA has announced that Canadian reporting issuers will need to begin reporting under IFRS, including comparative figures, by the first quarter of 2011. In the fourth quarter of 2010, the Audit Committee reviewed accounting policy decisions for all standards that were in effect at the end of the year ended December 31, 2010.

Note 4. Inventories

	2010	2009	2008
Parts and other consumables	**$ 9.0**	$ 14.2	$ 7.7
Fuel	**10.5**	10.4	15.5
	$ 19.5	$ 24.6	$ 23.2

Inventories expensed in cost of fuel and other plant operating expenses were $47.1 million for the year ended December 31, 2010 (December 31, 2009 $21.2 million; December 31, 2008 $40.5 million).

No write-down of inventory or reversal of a previous write-down was recognized in the years ended December 31, 2010, 2009 or 2008. As at December 31, 2010, 2009 and 2008, no inventories were pledged as security for liabilities.

Note 5. Property, plant and equipment

	2010			**2009**		
	Cost	**Accumulated Depreciation**	**Net Book Value**	**Cost**	**Accumulated Depreciation**	**Net Book Value**
Land	**$ 4.9**	**$**	**$ 4.9**	$ 5.0	$	$ 5.0
Plant and equipment	**1,439.2**	**455.3**	**983.9**	1,421.6	399.0	1,022.6
Other equipment	**10.1**	**9.3**	**0.8**	11.0	8.7	2.3
Construction in progress	**4.5**		**4.5**	34.8		34.8
	$ 1,458.7	**$ 464.6**	**$ 994.1**	$ 1,472.4	$ 407.7	$ 1,064.7

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Capital Power Income L.P.

Notes to the Consolidated Financial Statements (Continued)

Note 5. Property, plant and equipment (Continued)

	2008		
	Cost	Accumulated Depreciation	Net Book Value
Land	$ 3.3	$	$ 3.3
Plant and equipment	1,423.9	346.3	1,077.6
Other equipment	8.7	7.7	1.0
Construction in progress	24.1		24.1
	$ 1,460.0	$ 354.0	$ 1,106.0

Depreciation, amortization and accretion expense consists of:

	2010	2009	2008
Depreciation of property, plant and equipment	**$ 69.6**	$ 65.0	$ 55.9
Accretion of asset retirement obligations	**2.9**	1.9	1.6
Amortization of PPAs	**25.4**	27.8	31.4
Other amortization	**0.4**	(1.4)	(0.6)
	$ 98.3	$ 93.3	$ 88.3

Note 6. Power purchase arrangements

	2010			2009			2008		
	Cost	Accumulated Amortization	Net Book Value	Cost	Accumulated Amortization	Net Book Value	Cost	Accumulated Amortization	Net Book Value
PPAs	**$ 440.9**	**$ 150.9**	**$ 290.0**	$ 462.8	$ 132.4	$ 330.4	$ 530.0	$ 121.4	$ 408.6

The PPAs are being amortized over the remaining terms of the contracts, which range from four months to seventeen years.

Note 7. Goodwill

The changes in the carrying value of goodwill are as follows:

	2010	2009	2008
Goodwill, beginning of year	**$ 47.6**	$ 55.1	$ 50.9
Foreign currency translation adjustment	**(2.6)**	(7.5)	4.2
Goodwill, end of year	**$ 45.0**	$ 47.6	$ 55.1

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Capital Power Income L.P.

Notes to the Consolidated Financial Statements (Continued)

Note 8. Other assets

	2010	2009	2008
Net investment in lease	**$ 23.7**	$ 26.9	$ 33.2
Other long-term receivable	**17.6**		
Long-term investments	**20.3**	21.4	19.2
Receivable from Equistar		9.1	9.6
Other intangible assets:			
Cost	**1.4**	1.2	2.5
Accumulated amortization	**(0.2)**	(0.1)	(0.1)
	$ 62.8	$ 58.5	$ 64.4

Net investment in lease

The PPA under which the power generation facility located in Oxnard, California operates is considered to be a direct financing lease for accounting. The PPA expires in 2020. The current portion of the net investment in lease of $1.5 million is included in accounts receivable (2009 $1.6 million; 2008 $1.8 million). Financing income for the year ended December 31, 2010 of $2.5 million is included in revenues (2009 $2.9 million; 2008 $2.8 million).

Other long-term receivable

Other long-term receivable relates to amounts recoverable over the remaining term of the Oxnard PPA for unbilled services.

Long-term investment and asset impairment charge

The Partnership's common ownership interest in Primary Energy Recycling Holdings LLC (PERH) was accounted for on the equity basis up to August 24, 2009 and on a cost basis thereafter as a result of a recapitalization of PERH and changes to the management agreement between the Partnership, PERH, Primary Energy Recycling Corporation (PERC) and Primary Energy Operations LLC. The Partnership has converted all of its common and preferred interests in PERH to a 14.3% common equity interest in PERH in connection with a recapitalization of PERH pursuant to which all previously outstanding common and preferred interests in PERH, including those held by the Partnership and PERC, were converted to new common equity interests. No gain or loss was recorded on the conversion.

In November 2009, the Partnership exercised its pre-emptive right to maintain its pro-rata interest (14.3%) in PERH whereby the Partnership subscribed for new common equity interests at an aggregate subscription price of $8.8 million (US$8.3 million).

The Partnership recorded a pre-tax impairment charge of $24.1 million during the year ended December 21, 2008 to write down the investment based on its fair value.

Capital Power Income L.P.

Notes to the Consolidated Financial Statements (Continued)

Note 9. Long-term debt

	Effective interest rate	2010	2009	2008
Senior unsecured notes, due June 2036 at 5.95%	**6.12%**	**210.0**	$ 210.0	$ 210.0
Senior unsecured notes (US$190.0 million), due July 2014 at 5.90%	**6.16%**	**189.0**	199.7	231.4
Senior unsecured notes (US$150.0 million), due August 2017 at 5.87%	**6.01%**	**149.2**	157.6	182.7
Senior unsecured notes (US$75.0 million), due August 2019 at 5.97%	**6.11%**	**74.6**	78.8	91.4
Secured term loan at 11.25%	**11.57%**		1.4	2.6
Revolving credit facilities at floating rates	**2.85%**	**86.1**	78.3	86.7
		708.9	725.8	804.8
Less: Current portion of long-term debt			1.4	1.3
Deferred debt issue costs		**4.4**	5.0	5.0
		$ 704.5	$ 719.4	$ 798.5

Senior unsecured notes

The notes are unsecured obligations of the Partnership and, subject to statutory preferred exemptions, rank equally with all other unsecured and unsubordinated indebtedness of the Partnership. Interest on the senior unsecured notes is payable semi-annually.

Revolving credit facilities

The Partnership has available to it unsecured two-year credit facilities of $100.0 million, $100.0 million and $125.0 million, for a total of $325.0 million, committed to 2012 and uncommitted amounts of $20.0 million and $20.0 million (US$20.0 million). At December 31, 2010, $86.1 million was drawn against these facilities (December 31, 2009 $78.3 million; December 31, 2008 $86.7 million).

Under the terms of the extendible facilities, the Partnership may obtain advances by way of prime loans, US base rate loans, US LIBOR loans and bankers' acceptances. Depending on the facility, amounts drawn by way of prime loans bear interest at the prevailing Canadian prime rate or the average one-month bankers' acceptance rate plus a spread based on the Partnership's credit rating. Amounts drawn by way of US LIBOR loans bear interest at the prevailing LIBOR rate plus a spread based on the Partnership's credit rating. Amounts drawn by way of bankers' acceptances bear interest at the prevailing bankers' acceptance rate plus a spread based on the Partnership's credit rating. The Partnership's revolving credit facilities may be used for general partnership purposes including working capital support.

Deferred debt issue costs

At December 31, 2010 deferred debt issue costs were $7.3 million, net of accumulated amortization of $2.9 million (December 31, 2009 deferred debt issue costs were $6.8 million, net of accumulated amortization of $1.8 million; December 31, 2008 deferred debt issue costs were $6.4 million, net of accumulated amortization of $1.4 million).

Capital Power Income L.P.

Notes to the Consolidated Financial Statements (Continued)

Note 9. Long-term debt (Continued)

Financial charges and other, net

	2010	2009	2008
Interest on long-term debt	**$ 39.0**	$ 42.6	$ 40.3
Foreign exchange losses	**0.3**	1.0	26.2
Interest on Equistar receivable	**(1.8)**		
Losses from equity investment		3.1	6.3
Dividend income		(1.1)	(1.9)
Other	**2.6**	0.8	(0.2)
	$ 40.1	$ 46.4	$ 70.7

Note 10. Other liabilities

	2010	2009	2008
Asset retirement obligations	**$ 29.3**	$ 28.8	$ 28.6
Deferred revenue	**6.5**	4.5	
Other long-term liabilities	**1.3**	1.5	4.7
	$ 37.1	$ 34.8	$ 33.3

Asset retirement obligations

	2010	2009	2008
Asset retirement obligations, beginning of year	**$ 28.8**	$ 28.6	$ 21.1
Adjustment to asset retirement obligations	**(1.5)**		
Assumption of Morris asset retirement obligations			5.9
Accretion of asset retirement obligations	**2.9**	1.9	1.6
Foreign currency translation adjustment	**(0.9)**	(1.7)	
Asset retirement obligations, end of year	**$ 29.3**	$ 28.8	$ 28.6

At December 31, 2010, the estimated cost to settle the Partnership's asset retirement obligations was $129.4 million (2009 $146.0 million; 2008 $156.9 million) calculated using inflation rates ranging from 2.0% to 3.0% per annum (2009 2.1% to 3.0%; 2008 3.0%). The estimated cash flows were discounted at rates ranging from 6.4% to 7.5% (2009 6.4% to 7.5%; 2008 6.4% 7.5%). At December 31, 2010, the expected timing of payment for settlement of the obligations ranges from 9 to 80 years.

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Capital Power Income L.P.

Notes to the Consolidated Financial Statements (Continued)

Note 11. Preferred shares issued by a subsidiary company

In November 2009, a subsidiary of the Partnership issued 4 million 7.0% Cumulative Rate Reset Preferred Shares, Series 2 (the Series 2 Shares) priced at $25.00 per share. The Series 2 Shares pay fixed cumulative dividends of $1.75 per share per annum, as and when declared, for the initial five-year period ending December 31, 2014. The dividend rate will reset on December 31, 2014 and every five years thereafter at a rate equal to the sum of the then five-year Government of Canada bond yield and 4.18%. The Series 2 Shares are redeemable at $25.00 per share by the Partnership on December 31, 2014 and on December 31 every five years thereafter. The holders of the Series 2 Shares will have the right to convert their shares into Cumulative Floating Rate Preferred Shares, Series 3 (the Series 3 Shares) of the Partnership, subject to certain conditions, on December 31, 2014 and every five years thereafter. The holders of Series 3 Shares will be entitled to receive quarterly floating rate cumulative dividends, as and when declared by the board of directors of the Partnership, at a rate equal to the sum of the then 90-day Government of Canada treasury bill rate and 4.18%.

A subsidiary of the Partnership has issued 5 million 4.85% Cumulative Redeemable Preferred Shares, Series 1 priced at $25.00 per share with dividends payable on a quarterly basis at the annual rate of $1.2125 per share. On or after June 30, 2012, the shares are redeemable by the subsidiary company at $26.00 per share, declining by $0.25 each year to $25.00 per share after June 30, 2016. The shares are not retractable by the holders. Under the terms of the preferred share issue, the Partnership will not make any distributions on partnership units if the declaration or payment of dividends on the preferred shares is in arrears.

Dividends will not be paid on the preferred shares if the senior unsecured notes of the Partnership are in default.

The Partnership paid dividends of $13.1 million in 2010 (2009 $7.2 million; 2008 $6.1 million) and incurred associated net current and future income taxes of $1.0 million (2009 $0.7 million; 2008 $0.5 million) for an after-tax preferred share dividend of $14.1 million (2009 $7.9 million; 2008 $6.6 million).

Note 12. Partners' capital

	2010		2009	
	Number of Units	Millions of Dollars	Number of Units	Millions of Dollars
Partnership capital, beginning of year	**54,153,871**	**$ 1,200.6**	53,897,279	$ 1,197.1
Partnership units issued pursuant to distribution reinvestment plan	**1,670,657**	**27.0**	256,592	3.5
Partnership capital, end of year	**55,824,528**	**$ 1,227.6**	54,153,871	$ 1,200.6

	2008	
	Number of Units	Millions of Dollars
Partnership capital, beginning and end of year	53,897,279	$ 1,197.1

The Partnership is authorized to issue an unlimited number of limited partnership units. Each unit represents an equal, undivided limited partnership interest in the Partnership and entitles the

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Capital Power Income L.P.

Notes to the Consolidated Financial Statements (Continued)

Note 12. Partners' capital (Continued)

holder to participate equally in distributable cash and net income. Units are not subject to future calls or assessments and entitle the holder to limited liability. Each unit is transferable, subject to the requirements referred to in the Partnership Agreement.

In October 2009, the Partnership implemented a Premium Distribution (Premium Distribution is a trademark of Canaccord Capital Corporation) and Distribution Reinvestment Plan (the Plan) that provides eligible unitholders with two alternatives to receiving the monthly cash distributions, including the option to accumulate additional units in the Partnership by reinvesting cash distributions in additional units issued at a 5% discount to the Average Market Price of such units (as defined in the Plan) on the applicable distribution payment date. Alternatively, under the Premium Distribution™ component of the Plan, eligible unitholders may elect to exchange these additional units for a cash payment equal to 102% of the regular cash distribution on the applicable distribution payment date.

In 2010, the weighted average number of units outstanding was 54,968,742 (2009 53,914,046; 2008 53,897,279).

Note 13. Accumulated other comprehensive income

The components of accumulated other comprehensive income are as follows:

	2010	2009	2008
Cumulative unrealized losses on translating net assets of self-sustaining foreign operations	**$ (159.3)**	$ (131.9)	$ (66.0)
Deferred gains on derivatives de-designated as cash flow hedges	**0.4**	0.9	1.3
Unrealized losses on derivative instruments designated as cash flow hedges	**(50.9)**	(6.4)	
Total accumulated other comprehensive income	**$ (209.8)**	$ (137.4)	$ (64.7)

Note 14. Income taxes

Components of income tax recovery	**2010**	**2009**	**2008**
Current income taxes	**$ 0.4**	$ 1.3	$ 1.7
Future income taxes	**(9.8)**	(10.2)	(33.1)
	$ (9.4)	$ (8.9)	$ (31.4)

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Capital Power Income L.P.

Notes to the Consolidated Financial Statements (Continued)

Note 14. Income taxes (Continued)

Reconciliation of income tax recovery

	2010	2009	2008
Net income (loss) from continuing operations before income taxes and preferred share dividends	**$ 35.2**	$ 56.8	$ (91.9)
Combined federal and provincial tax rate	**29.0%**	31.0%	31.5%
Expected income tax expense (recovery)	**10.2**	17.6	(28.9)
Amounts related to (non-taxable) non-deductible foreign exchange and other permanent differences	**(9.9)**	(6.7)	2.7
Changes in valuation allowance	**(0.1)**	(4.5)	12.7
Change due to enactment of rate changes	**0.5**	0.7	
Income allocated to Partnership unitholders	**(7.5)**	0.1	(15.8)
Taxes related to prior periods	**1.3**	(9.9)	
Statutory and other rate differences	**1.4**	(9.6)	6.4
Other	**(5.3)**	3.4	(8.5)
Actual income tax recovery	**$ (9.4)**	$ (8.9)	$ (31.4)

Future income tax assets and liabilities

	2010	2009	2008
Loss carryforwards	**$ 87.1**	$ 75.4	$ 53.9
Difference in accounting and tax basis of intangible assets	**2.7**	4.5	6.7
Asset retirement obligations	**5.7**	4.1	3.9
Deferred financing charges	**3.5**	2.4	1.8
Non-deductible accrued amounts	**1.7**	1.8	2.1
Unrealized losses on derivative instruments	**16.0**	0.8	5.1
Deferred revenue	**2.9**	1.7	
Long-term receivable		0.8	1.0
Other			0.9
Future income tax assets	**$ 119.6**	$ 91.5	$ 75.4
Difference in accounting and tax basis of plant, equipment and PPAs	**$ (109.2)**	$ (114.5)	$ (115.4)
Unrealized foreign exchange gains	**(4.9)**	(4.3)	(1.6)
Long-term receivable	**(7.0)**		
Other	**(0.9)**	(2.3)	
Future income tax liabilities	**$ (122.0)**	$ (121.1)	$ (117.0)
Net future income tax liabilities	**$ (2.4)**	$ (29.6)	$ (41.6)

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Capital Power Income L.P.

Notes to the Consolidated Financial Statements (Continued)

Note 14. Income taxes (Continued)

Presented on the balance sheet as follows:

	2010	2009	2008
Current assets	**$ 7.1**	$ 1.9	$ 2.3
Non-current assets	**41.2**	35.0	16.8
Current liabilities		(3.8)	
Non-current liabilities	**(50.7)**	(62.7)	(60.7)
	$ (2.4)	$ (29.6)	$ (41.6)

Income taxes

The Partnership follows the liability method of accounting for income taxes, whereby income taxes are recognized on differences between the financial statement carrying values and the respective income tax basis of assets and liabilities. Future income tax assets and liabilities are measured using the substantively enacted tax rates and laws that will be effect when the temporary differences are expected to be recovered or settled. To the extent that the realization of a future tax asset is not considered 'more likely than not,' a valuation allowance is provided.

Taxation of flow-through entities

Pursuant to the Income Tax Act (Canada), beginning on January 1, 2011, the Partnership will be subject to a specified investment flow-through (SIFT) distribution tax of 16.5% (15% beginning in 2012) along with a provincial tax component of 10%. The tax rates are equivalent to the substantially enacted corporate income tax rates, but apply to distributions of certain types of income. As the partnership generates cash flows from both Canada and the United States, only the cash flows generated in Canada would be subject to the SIFT tax. Cash flows generated in the United States are exempt from the SIFT tax as they are subject to United States taxation. The Partnership expects that its distributions will be treated as eligible dividends starting on January 1, 2011.

The net future income tax liability relating to the SIFT legislation decreased $17.0 million to $45.7 million in 2010 (2009 $62.7 million; 2008 $60.7 million) due a reduction in the net taxable temporary differences which are expected to reverse subsequent to 2010. This estimate of the net future tax liability is based on the current best estimate of the accounting and tax values that exist on December 31, 2010. The Partnership and its Canadian subsidiary limited partnerships have net taxable temporary differences of $185.8 million (2009 $245.7 million, 2008 $309.1 million) of which the tax effects of $184.0 million (2009 $250.5 million, 2008 $230.5 million) are reflected in these consolidated financial statements due to the enactment of the SIFT legislation in 2007.

Taxation of corporate subsidiaries

Current and future taxes have been reflected in respect of taxable income and temporary differences relating to the corporate subsidiaries of the Partnership. The Canadian corporate subsidiaries of the Partnership are subject to tax on their taxable income at a rate of approximately 29% (2009 31.0%; 2008 31.5%) whereas the U.S. corporate subsidiaries are subject to tax on their taxable income at rates varying from 34% to 41% (2009 34.0% to 41.0%; 2008 34.0% 41.0%). Future income taxes relating to the corporate subsidiaries have been reflected in these consolidated

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Capital Power Income L.P.

Notes to the Consolidated Financial Statements (Continued)

Note 14. Income taxes (Continued)

financial statements except in respect of deductible temporary differences of $4.4 million (2009 $4.4 million; 2008 $54.9 million) for which no tax benefit has been recognized.

Income tax loss carry forwards

As at December 31, 2010, the Partnership has income tax loss carry forwards of approximately US $151.4 million (2009 US$128.9 million, 2008 US$84.8 million) in the US, which may be used to reduce future US taxable income. Of these losses, US$22.3 million (2009 US$22.3 million; 2008 US$22.3 million) expire between 2022 and 2025 with the remainder expiring thereafter and $18.1 million (2009 US$18.1 million; 2008 US$22.3 million) of the losses are restricted under Section 382 of the Internal Revenue Code. Under Section 382 of the Internal Revenue Code of 1986, as amended, the utilization of the restricted losses is limited to an annual amount of US$4.7 million.

As at December 31, 2010, the Partnership has both non-capital losses and capital losses that are available for carry forward in Canada. For Canadian income tax purposes, there are non-capital loss carry forwards of approximately $120.7 million (2009 $96.7 million; 2008 $56.3 million), which may be used to reduce future income taxes otherwise payable and which expire in the years 2011 to 2030. There are also capital loss carry forwards of $3.5 million (2009 $3.5 million; 2008 $14.9 million) which can be carried forward indefinitely. The tax benefit on $0.3 million (2009 $0.2 million; 2008 $0.1 million) of the non-capital losses carry forwards and on $3.5 million (2009 $3.5 million; 2008 $14.9 million) of the capital loss carry forwards have been fully offset by the recognition of a valuation allowance.

Out of period adjustment

During the year ended December 31, 2009, the Partnership recorded an out-of-period adjustment of $9.7 million relating to 2007 and 2008 in order to recognize net future income tax assets associated with the Partnership's interest in PERH. Management determined that the impact of the adjustment was not material, either individually or in aggregate, to any of the prior periods' financial statements and accordingly, that a restatement of previously issued financial statements was not necessary.

Note 15. Financial instruments

Fair values and classification of financial assets and liabilities

The Partnership classifies its cash and cash equivalents and current and non-current derivative instruments assets and liabilities as held for trading and measures them at fair value. Accounts receivable are classified as loans and receivables and accounts payable and distributions payable are classified as other financial liabilities and are measured at amortized cost. The fair values of accounts receivable, accounts payable and distributions payable are not materially different from their carrying amounts due to their short-term nature. The investment in PERH is classified as available for sale and the net investment in lease is classified as loans and receivables. The net investment in lease and other long-term receivable relates to the Oxnard PPA, which is considered a direct financing lease for accounting purposes.

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Capital Power Income L.P.

Notes to the Consolidated Financial Statements (Continued)

Note 15. Financial instruments (Continued)

The classification, carrying amounts and fair values of the Partnership's other financial instruments are summarized as follows:

	2010			
	Carrying amount			
	Loans and receivables	Other financial liabilities	Total	Total fair value
Other assets net investment in lease and other long-term receivable	**$ 41.3**	**$**	**$ 41.3**	**$ 42.4**
Long-term debt (including current portion)		**(704.5)**	**(704.5)**	**(697.7)**

	2009			
	Carrying amount			
	Loans and receivables	Other financial liabilities	Total	Total fair value
Other assets net investment in lease and other long-term receivable	$ 26.9	$	$ 26.9	$ 27.1
Other assets receivable from Equistar	9.1		9.1	$ 9.1
Long-term debt (including current portion)		(720.8)	(720.8)	(667.7)

	2008			
	Carrying amount			
	Loans and receivables	Other financial liabilities	Total	Total fair value
Other assets net investment in lease and other long-term receivable	$ 33.2	$	$ 33.2	$ 33.1
Other assets receivable from Equistar	9.6		9.6	$ 9.6
Long-term debt (including current portion)		(799.8)	(799.8)	(685.9)

The fair value of the Partnership's long-term debt is based on determining an appropriate yield for the Partnership's debt as at December 31, 2010, 2009 and 2008. This yield is based on an estimated credit spread for the Partnership over the yields of long-term Government of Canada and U.S. Government bonds that have similar maturities to the Partnership's debt. The estimated credit spread is based on the Partnership's indicative spread as published by independent financial institutions.

The Partnership has used the carrying amount of its investment in PERH as its fair value as the shares are not quoted in an active market and their fair value therefore cannot be measured reliably.

The fair value of the Partnership's net investment in the financing lease and related long-term receivables is based on the estimated interest rate implicit in a comparable lease arrangement as at December 31, 2010, 2009 and 2008.

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Capital Power Income L.P.

Notes to the Consolidated Financial Statements (Continued)

Note 15. Financial instruments (Continued)

Derivative instruments

Derivative instruments are held to manage financial risk related to energy procurement and treasury management. All derivative instruments, including embedded derivatives, are classified as held for trading and are recorded at fair value on the balance sheet unless exempted from derivative treatment as a normal purchase, sale or usage. All changes in their fair value are recorded in net income.

The derivative instruments assets and liabilities used for risk management purposes consist of the following:

	December 31, 2010			
	Natural gas		Foreign exchange	
	Hedges	Non-hedges	Non-hedges	Total
Derivative instruments assets:				
Current	**$**	**$**	**$ 10.4**	**$ 10.4**
Non-current			**29.7**	**29.7**
Derivative instruments liabilities:				
Current	**(16.2)**	**(3.0)**	**(1.9)**	**(21.1)**
Non-current	**(76.9)**		**(5.0)**	**(81.9)**
	$ (93.1)	**$ (3.0)**	**$ 33.2**	**$ (62.9)**
Net notional amounts:				
Gigajoules (GJs) (millions)	**37.8**	**6.5**		
U.S. foreign exchange (U.S. dollars in millions)			**309**	
Contract terms (years)	**6.0**	**0.8 to 2.0**	**0.2 to 5.5**	

	December 31, 2009			
	Natural gas		Foreign exchange	
	Hedges	Non-hedges	Non-hedges	Total
Derivative instruments assets:				
Current	$ 1.0	$ 2.5	$ 4.3	$ 7.8
Non-current		6.0	25.8	31.8
Derivative instruments liabilities:				
Current	(2.1)		(0.8)	(2.9)
Non-current	(32.8)		(3.6)	(36.4)
	$ (33.9)	$ 8.5	$ 25.7	$ 0.3
Net notional amounts:				
Gigajoules (GJs) (millions)	45.0	11.0		
U.S. foreign exchange (U.S. dollars in millions)			395	
Contract terms (years)	1.0 to 7.0	0.0 to 3.0	0.2 to 6.0	

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Capital Power Income L.P.

Notes to the Consolidated Financial Statements (Continued)

Note 15. Financial instruments (Continued)

	December 31, 2008			
	Natural gas		Foreign exchange	
	Hedges	Non-hedges	Non-hedges	Total
Derivative instruments assets:				
Current	$	$ 15.5	$ 7.3	$ 22.8
Non-current		23.5	3.6	27.1
Derivative instruments liabilities:				
Current		(1.5)	(11.5)	(13.0)
Non-current		(0.6)	(37.9)	(38.5)
	$	$ 36.9	$ (38.5)	$ (1.6)
Net notional amounts:				
Gigajoules (GJs) (millions)		69.0		
U.S. foreign exchange (U.S. dollars in millions)			456.9	
Contract terms (years)		0.1 to 8.0	0.2 to 6.0	

The fair value of derivative instruments are determined, where possible, using exchange or over-the-counter price quotations by reference to quoted bid, ask, or closing market prices, as appropriate in active markets. Where there are limited observable prices due to illiquid or inactive markets, the Partnership uses appropriate valuation and price modeling commonly used by market participants to estimate fair value. Fair value determined using valuation models requires the use of assumptions concerning the amount and timing of future cash flows. In general, fair value amounts reflect management's best estimates using external readily observable market data such as future prices, interest rate yield curves, foreign exchange rates, discount rates for time value, and volatility for all of the Partnership's financial instruments. It is possible that the assumptions used in establishing fair value amounts will differ from future outcomes and the impact of such variations could be material.

Unrealized and realized pre-tax gains and (losses) on derivative instruments recognized in net income and other comprehensive income were:

	Income statement category	2010	2009	2008
Foreign exchange non-hedges	Revenue	**$ 12.4**	$ 59.8	$ (57.6)
Natural gas non-hedges	Cost of fuel	**(9.3)**	(52.1)	(30.4)
Natural gas hedges ineffective portion	Cost of fuel	**(2.2)**	(0.3)	
Natural gas hedges effective portion	Other comprehensive loss	**(59.1)**	(8.9)	

If hedge accounting requirements are not met, unrealized and realized gains and losses on natural gas derivatives are recorded in cost of fuel. If hedge accounting requirements are met, realized gains and losses on natural gas derivatives are recorded in cost of fuel while unrealized gains and losses are recorded in other comprehensive income.

The Partnership has elected to apply hedge accounting effective July 31, 2009, on certain derivative instruments it uses to manage commodity price risk relating to natural gas prices. For the year ended December 31, 2010, the change in the fair value of the ineffective portion of hedging derivatives required to be recognized in the income statement was $2.2 million. Of the $50.9 million of after tax losses related to derivative instruments designated as cash-flow hedges included in accumulated other comprehensive income at December 31, 2010, losses of $8.8 million, net of income

Capital Power Income L.P.

Notes to the Consolidated Financial Statements (Continued)

Note 15. Financial instruments (Continued)

taxes of $3.2 million are expected to settle and be reclassified to net income during the year ended December 31, 2011. The Partnership's cash flow hedges extend up to 2016.

Fair value hierarchy

Fair value represents the Partnership's estimate of the price at which a financial instrument could be exchanged between knowledgeable and willing parties in an orderly arm's length transaction under no compulsion to act. Fair value measurements recognized in the consolidated balance sheets are categorized into levels within a fair value hierarchy based on the nature of the valuation inputs, and precedence is given to those fair value measurements calculated using observable inputs over those using unobservable inputs. The determination of fair value requires judgment and is based on market information where available and appropriate. The following levels were established for each input:

Level 1: Fair value is based on quoted prices (unadjusted) in active markets for identical instruments. Financial instruments classified in Level 1 include cash and cash equivalents, including highly liquid short term investments.

Level 2: Fair value is based on other than unadjusted quoted prices included in Level 1, which are either directly or indirectly observable at the reporting date. Level 2 includes those financial instruments that are valued using commonly used valuation techniques, such as the discounted cash flow model or black-scholes option pricing models. Valuation models use inputs such as quoted prices for similar instruments in active markets, quoted prices for identical or similar instruments in markets that are not active but observable, and other observable inputs that are principally derived from or corroborated by observable market data for substantially the full term of the instrument. Financial instruments classified in Level 2 includes commodity, foreign exchange, and interest rate derivatives whose values are determined based on broker quotes, observable trading activity for similar, but not identical instruments, and prices published on information platforms and exchanges.

Level 3: Fair value is based unobservable inputs that are supported by little or no market activity and that are significant to the fair value of the instrument. Level 3 includes financial instruments that are also valued using commonly used valuation techniques described in Level 2, however some inputs used in the models may not be based on observable market data and therefore based on the Partnership's best estimate from the perspective of a market participant. There are no financial instruments classified in Level 3 at the reporting date.

The fair value measurement of a financial instrument is included in only one of the three levels, the determination of which is based upon the lowest level input that is significant to the derivation of the fair value. The Partnership's assessment of the significance of a particular input to the fair value measurement requires judgment thereby affecting the placement within the fair value hierarchy levels. The following table presents the Partnership's financial instruments measured at fair

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Notes to the Consolidated Financial Statements (Continued)

Note 15. Financial instruments (Continued)

value on a recurring basis in the consolidated balance sheets, classified using the fair value hierarchy described above:

	Level 1	Level 2	Level 3	Total
Financial assets:				
Cash	**$ 27.5**	**$**	**$**	**$ 27.5**
Derivative instrument assets:				
Foreign exchange non-hedges		**40.1**		**40.1**
Derivative instrument liabilities:				
Natural gas hedges		**(93.1)**		**(93.1)**
Natural gas non-hedges		**(3.0)**		**(3.0)**
Foreign exchange non-hedges		**(6.9)**		**(6.9)**

There were no significant transfers between Level 1 and 2 for the period ended December 31, 2010.

Note 16. Changes in non-cash working capital

	2010	2009	2008
Accounts receivable	**$ 8.4**	$ 8.5	$ 10.5
Inventories	**(14.7)**	(1.2)	(4.7)
Accounts payable	**(1.1)**	(16.7)	8.9
Other	**0.1**	1.1	(1.4)
	$ (7.3)	$ (8.3)	$ 13.3

Note 17. Risk management

Risk management overview

The Partnership is exposed to a number of different financial risks arising from natural business exposures as well as its use of financial instruments which include market, interest, credit and liquidity risks. The Partnership's overall risk management process is designed to identify, manage and mitigate business risk which includes financial risk, among others. Financial risk is managed according to objectives, targets and policies set forth by the Board of Directors. Risk management strategies, policies and limits are designed to ensure the risk exposures are managed within the Partnership's business objectives and risk tolerance. The Partnership's risk management objective is to protect and minimize volatility in cash provided by operating activities and distributions therefrom.

Market risk

Market risk is the risk of loss that results from changes in market factors such as commodity prices, foreign currency exchange rates, interest rates and equity prices. The level of market risk to which the Partnership is exposed at any point in time varies depending on market conditions, expectations of future price or market rate movements and composition of the Partnership's financial assets and liabilities held, non-trading physical assets and contract portfolios. Commodity price risk management and the associated credit risk management are carried out in accordance with Partnership's financial risk management policies, as approved by the Board of Directors.

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Capital Power Income L.P.

Notes to the Consolidated Financial Statements (Continued)

Note 17. Risk management (Continued)

To manage the exposure related to changes in market risk, the Partnership uses various risk management techniques including the use of derivative instruments. Derivative instruments may include financial and physical forward contracts. Such instruments may be used to establish a fixed price for an energy commodity, an interest-bearing obligation or an obligation denominated in a foreign currency. Market risk exposures are monitored regularly against approved risk limits and control processes are in place to monitor that only authorized activities are undertaken.

The sensitivities provided in each of the following risk discussions disclose the effect of reasonably possible changes in relevant prices and rates on net income at the reporting date. The sensitivities are hypothetical and should not be considered to be predictive of future performance or indicative of earnings on these contracts. The Partnership's actual exposure to market risks is constantly changing as the Partnership's portfolio of debt, foreign currency and commodity contracts change. Changes in fair value based on market variable fluctuations cannot be extrapolated as the relationship between the change in the market variable and the change in fair value may not be linear. In addition, the effect of a change in a particular market variable on fair values or cash flows is calculated without considering interrelationships between the various market rates or mitigating actions that would be taken by the Partnership.

Commodity price risk

The Partnership is exposed to commodity price risk as part of its normal business operations, particularly in relation to the prices of electricity, natural gas and coal. The Partnership actively manages commodity price risk by optimizing its asset and contract portfolios in the following manner:

- The Partnership commits substantially all of its power supply to long-term fixed price PPAs which limits the exposure to electricity prices;

- The Partnership purchases natural gas under long-term fixed price supply contracts to reduce the exposure to natural gas prices on certain of its natural gas fired generation plants; and

- The Partnership has entered into certain PPAs whereby the counterparty bears the variable costs linked to the price of natural gas or coal.

The following represents the sensitivity of net income to derivative instruments that are accounted for on a fair value basis. As at December 31, 2010, with all other variables unchanged, a $1.00/GJ increase (decrease) of the natural gas price is estimated to increase (decrease) net income by approximately $4 million after tax and other comprehensive income by approximately $24 million after tax. This assumption is based on the volumes or position held at December 31, 2010.

Foreign exchange risk

The Partnership is exposed to foreign exchange risk on its net investment in self-sustaining foreign operations. The risk is that the Canadian dollar value of the U.S. dollar net investment in self-sustaining foreign operations will vary as a result of the movements in exchange rates.

The Partnership's foreign exchange management policy is to manage economic and material transactional exposures arising from movements in the Canadian dollar against the U.S. dollar. The Partnership's foreign currency exposure arises from anticipated U.S. dollar denominated cash flows from its U.S. operations and from debt service obligations on U.S. dollar borrowings. The Partnership

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Capital Power Income L.P.

Notes to the Consolidated Financial Statements (Continued)

Note 17. Risk management (Continued)

coordinates and manages foreign currency risk through the General Partner's central Treasury function. Foreign exchange risk is managed by considering naturally occurring opposite movements wherever possible and then managing any material residual foreign currency exchange risks according to the policies approved by the Board of Directors.

The Partnership primarily uses foreign currency forward contracts to fix the Canadian currency equivalent of its U.S. currency expected cash flows thereby reducing its anticipated U.S. denominated transactional exposure. The Partnership's foreign currency risk management practice is to ensure a majority of the net currency exposure on anticipated transactions within 7 years are economically hedged. At December 31, 2010, US$308.9 million of future anticipated net cash flows from its U.S. plants were economically hedged for 2011 to 2016 at a weighted average rate of $1.13 per US $1.00.

At December 31, 2010, holding all other variables constant, a $0.10 strengthening (weakening) of the Canadian dollar against the U.S. dollar would increase (decrease) net income by approximately $19 million after tax as a result of changes in the fair value of foreign exchange contracts.

This sensitivity analysis excludes translation risk associated with the application of the current rate and temporal translation methods, financial instruments that are non-monetary items, and financial instruments denominated in the functional currency in which they are transacted and measured.

Interest rate risk

The Partnership is exposed to changes in interest rates on its cash and cash equivalents and floating rate short-term and long-term obligations. The Partnership is exposed to interest rate risk from the possibility that changes in the interest rates will affect future cash flows or the fair values of its financial instruments. In some circumstances, floating rate funding may be used for short-term borrowings and other liquidity requirements. At December 31, 2010 the Partnership held $86.1 million in floating rate debt (December 31, 2009 $78.3 million; December 31, 2008 $86.7 million). The Partnership may also use derivative instruments to manage interest rate risk. At December 31, 2010, 2009 and 2008 the Partnership did not hold any interest rate derivative instruments.

Holding all other variables constant and assuming that the amount and mix of floating rate debt remains unchanged from that held at December 31, 2010, a 100 basis point change to interest rates would have a $0.9 million impact on net income and would have no impact on other comprehensive income.

Credit risk

The electricity and steam generated at the Partnership's facilities are sold under long-term contracts to 23 customers. Customers accounting for 10% or more of the Partnership's revenue in 2010 were as follows:

	2010	2009	2008
Ontario Electricity Financial Corporation	**26%**	23%	26%
San Diego Gas & Electric Company	**11%**	10%	18%
British Columbia Hydro and Power Authority	**11%**	10%	11%

Capital Power Income L.P.

Notes to the Consolidated Financial Statements (Continued)

Note 17. Risk management (Continued)

The Partnership has exposure to credit risk associated with counterparty default under the Partnership's PPAs, fuel supply agreements and foreign currency hedges. In the event of a default by a counterparty, existing PPAs may not be replaceable on similar terms as pricing in many of these agreements is favourable relative to their current markets. Credit risk is associated with the ability of counterparties to satisfy their contractual obligations to the Partnership, including payment and performance. Credit risk is managed by making appropriate credit assessments of counterparties on an ongoing basis, dealing primarily with creditworthy counterparties, diversifying the risk by using several counterparties and where appropriate and contractually allowed, requiring the counterparty to provide appropriate security.

Maximum credit risk exposure

The Partnership has the following financial assets that are exposed to credit risk:

		2010	
	Canada	U.S.	Total
Trade receivables	$ 21.1	$ 31.4	$ 52.5
Other assets net investment in lease and other long-term receivable		41.3	41.3
Derivative instruments current assets	10.4		10.4
Derivative instruments non-current assets	29.7		29.7
	$ 61.2	$ 72.7	$ 133.9

The maximum credit exposure of these assets is their carrying amount. No amounts were held as collateral at December 31, 2010.

Accounts receivable

Accounts receivable consist primarily of amounts due from customers including industrial and commercial customers, government-owned or sponsored entities, regulated public utility distributors and other counterparties. The Partnership historically has not experienced credit losses and accordingly has not provided for an allowance for doubtful accounts. The Partnership evaluates the need for an allowance for potential credit losses by reviewing any overdue accounts and monitoring changes in the credit profiles of counterparties. The Partnership manages its credit risk exposures by dealing with creditworthy counterparties and, where appropriate and contractually allowed, taking back appropriate security from the counterparty. The Partnership determines the creditworthiness of counterparties using its own assessments and credit ratings by Standard and Poor's (S&P) and DBRS Limited (DBRS) if available.

No material accounts receivable were past due and there was no provision for credit losses associated with these receivables and financial derivative instruments as all balances are considered to be fully recoverable. Accounts receivable are mostly from counterparties with an investment grade rating assigned by S&P.

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Capital Power Income L.P.

Notes to the Consolidated Financial Statements (Continued)

Note 17. Risk management (Continued)

Liquidity risk

Liquidity risk is the risk that the Partnership will not be able to meet its financial obligations as they come due. The Partnership's liquidity is managed centrally through the General Partner's Treasury function. The Partnership manages liquidity through regular monitoring of cash and currency requirements by preparing short-term and long-term cash flow forecasts and matching the maturity profiles of financial assets and liabilities to identify financing requirements. The financing requirements are addressed through a combination of committed and demand revolving credit facilities and access to capital markets.

As at December 31, 2010, the Partnership had available bank credit facilities of $238.8 million committed to 2012 as discussed in Note 11 Long-term debt. In addition, the Partnership has a Canadian shelf prospectus under which it may raise up to $600.0 million in partnership units or debt securities. The Canadian shelf prospectus expires in August 2012.

The Partnership has a long-term debt rating of BBB/stable and BBB(high)/under review (negative), assigned by S&P and DBRS respectively.

The following are the undiscounted cash flow requirements and contractual maturities of the Partnership's financial liabilities, including interest payments as at December 31, 2010:

	Within 1 year	Between 1 & 2 years	Between 2 & 3 years	Between 3 & 4 years	Between 4 & 5 years	Beyond 5 years	Total
Non-derivative financial liabilities:							
Long-term debt[1]	$	$ 86.1	$	$ 189.0	$	$ 433.8	$ 708.9
Interest payments on long-term debt	39.5	39.1	36.9	32.2	25.7	291.5	464.9
Accounts payable and accrued liabilities[2]	36.5						36.5
Distributions payable	8.2						8.2
Derivative financial liabilities:							
Net forward exchange contracts	$ 1.9	$ 2.2	$ 1.4	$ 0.9	$ 0.9	$	$ 7.3
Total	$ 86.1	$ 127.4	$ 38.3	$ 222.1	$ 26.6	$ 725.3	$ 1,225.8

(1) Excluding deferred debt issue costs of $4.4 million.

(2) Excluding interest on long-term debt of $10.5 million and non-cash accruals of $5.9 million.

Note 18. Capital management

The Partnership's primary objectives when managing capital are to safeguard the Partnership's ability to continue as a going concern, provide stable distributions to unitholders, to maintain an investment grade credit rating and to facilitate the acquisition or development of power projects in Canada and the U.S. consistent with the growth strategy of the Partnership. The Partnership's objective of maintaining an investment grade credit rating is subject to change in order to manage the Partnership's growth strategy with changing economic circumstances. The Partnership manages its capital structure in a manner consistent with the risk characteristics of the underlying assets. This

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Capital Power Income L.P.

Notes to the Consolidated Financial Statements (Continued)

Note 18. Capital management (Continued)

overall objective and policy for managing capital remained unchanged in 2010 from the prior comparative period.

The Partnership considers its capital structure to consist of long-term debt, preferred shares and partners' equity. The following table represents the total capital of the Partnership:

	2010	2009	2008
Long-term debt (including current portion)	**$ 704.5**	$ 720.8	$ 799.8
Preferred shares	**219.7**	219.7	122.0
Partners' equity	**407.7**	519.5	632.3
Total capital	**$ 1,331.9**	$ 1,460.0	$ 1,554.1

The Partnership's credit and stability ratings are presented in the following table:

	2010	2009	2008
Credit rating			
S&P	BBB (stable)	BBB+/negative outlook	BBB+
DBRS	BBB(high)/under review (negative)	BBB(high)/negative trend	BBB(high)
Stability rating			
S&P	Not Rated	SR-2	SR-2
DBRS	STA-2 (low)	STA-2	STA-2

The Partnership has the following externally imposed requirements on its capital:

The Partnership must maintain a debt to total capitalization ratio, as defined in the debt agreements, of not more than 65%; and

In the event the Partnership is assigned both a rating of less than BBB+ by S&P and a rating of less than BBB(high) by DBRS, the Partnership also would be required to maintain a ratio of earnings before interest, income taxes, depreciation and amortization to interest expense of not less than 2.5 to 1.

At December 31, 2010, the Partnership's debt to capitalization ratio was 53% (December 31, 2009 49%; December 31, 2008 51%) and ratings of BBB/stable and BBB(high)/under review (negative) were assigned by S&P and DBRS respectively (December 31, 2009 BBB+/negative outlook and BBB(high)/negative trend; December 31, 2008 BBB+ and BBB(high)).

In order to manage its capital structure, the Partnership may adjust the amount of distributions paid to unitholders, issue or redeem preferred shares, issue or repay debt or issue or buy back partnership units.

Note 19. Related party transactions

In operating the Partnership's 20 power plants, the Partnership and CPC (and prior to July 1, 2009, EPCOR) engage in a number of related party transactions which are in the normal course of business. These transactions are based on contracts and many of the fees are escalated by inflation. The

Capital Power Income L.P.

Notes to the Consolidated Financial Statements (Continued)

Note 19. Related party transactions (Continued)

table below summarizes the amounts included in the calculation of net income for the years ended December 31, 2010, 2009 & 2008.

	2010	2009	2008
Transactions with CPC[(1)]			
Revenue Frederickson duct firing capacity fees	**$ 0.1**	$ 0.1	$ 0.1
Cost of fuel Greeley natural gas swap contract	**1.5**	2.6	0.3
Operating and maintenance expense	**47.5**	50.5	45.1
Management and administration			
Base fee	**0.9**	1.1	1.4
Incentive fee			2.3
Enhancement fee	**0.1**	0.2	2.4
General and administrative costs	**8.4**	8.0	5.9
	9.4	9.3	12.0
Transactions of discontinued operations			
Cost of fuel gas demand charge		1.1	2.2
Operating and maintenance expense		1.4	2.9
Acquisition and divestiture fees		0.2	1.9
Distributions	**29.1**	32.2	41.6

(1) Prior to July 1, 2009, EPCOR.

Greeley natural gas swap contract

The Partnership has entered into a three year natural gas swap contract with CPC to cover most of the anticipated natural gas supply for Greeley.

Operating and maintenance

CPC is entitled to receive a fee for services related to the operation and maintenance of the power plants under the Management and Operations Agreements. The annual fees are payable on an equal monthly basis. The annual fees for the Canadian plants and two U.S. plants are annually adjusted for inflation. The annual fees for the other U.S. plants are determined using a cost recovery basis.

Base and incentive fee

CPC is entitled to a base fee and an incentive fee under the Management and Operations Agreements in each fiscal year of the Partnership. The base fee is equal to 1% of the Partnership's annual cash distributions. The incentive fee is equal to 10% of annual distributable cash flow greater than $2.40 per unit. Annual distributable cash flow is defined as cash flow from operating activities before changes in non-cash operating working capital plus dividends from PERH less scheduled debt repayments and maintenance capital.

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Capital Power Income L.P.

Notes to the Consolidated Financial Statements (Continued)

Note 19. Related party transactions (Continued)

Enhancement fee

CPC can curtail operations of the Ontario power plants and re-sell contracted natural gas at market prices, rather than produce off-peak power at lower rates. CPC is entitled to receive an enhancement fee equivalent to 35% of the incremental profit.

General and administrative costs

CPC is entitled to a fee related to the salaries and wages for management and administration employees for the U.S. plants. The fee is payable monthly on a cost recovery basis. CPC is also entitled to receive a fee for Canadian support staff costs for public entity services required per the Management and Operations Agreements. The annual fee is payable on an equal monthly basis and is adjusted annually for changes in salary costs.

Acquisition and divestiture fees

CPC is entitled to acquisition and divestiture fees under the Transaction Fees and Costs Agreements. The fee is based on the transaction value of the acquisition or disposition.

Distributions

During the year ended December 31, 2010, the Partnership made cash distributions to CPC in the amount proportionate to its ownership interest. At December 31, 2010, CPC owned 29.6% of the Partnership's units (30.5% at December 31, 2009; at December 31, 2008 EPCOR owned 30.6% of the Partnership's units).

Note 20. Joint venture

A financial summary of the Partnership's investments in the Frederickson joint venture is as follows:

	2010	2009	2008
Current assets	**$ 1.8**	$ 4.9	$ 2.3
Long-term assets	**109.5**	120.3	145.3
Current liabilities	**0.7**	0.4	1.0
Long term liabilities	**0.5**	0.5	0.5
Revenues	**21.3**	23.3	23.0
Expenses	**12.9**	15.5	21.9
Net income	**8.4**	7.8	1.1
Cash provided by operating activities	**13.2**	13.3	8.1
Cash used in investing activities			
Cash used in financing activities	**(16.4)**	(10.2)	(8.4)

Note 21. Operating leases

From the point of view of a lessor, the terms of the Manchief, Mamquam, Moresby Lake, Greeley and Kenilworth PPAs (2009 and 2008 Manchief, Mamquam, Moresby Lake, Greeley, Kenilworth, Southport and Roxboro PPAs) are operating leases. At December 31, 2010, the carrying

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Notes to the Consolidated Financial Statements (Continued)

Note 21. Operating leases (Continued)

amounts of the property, plant and equipment of these facilities was $247.7 million less accumulated depreciation of $46.7 million (2009 $359.7 million and $47.6 million respectively; 2008 $317.6 million and $39.6 million respectively). The Partnership's revenues for the year ended December 31, 2010 include $74.9 million with respect to the PPAs for these plants (2009 $116.2 million; 2008 $141.8 million).

Note 22. Segment disclosures

The Partnership operates in one reportable business segment involved in the operation of independent power generation plants within British Columbia, Ontario and in the U.S. in California, Colorado, Illinois, New Jersey, New York, North Carolina and Washington State.

Geographic information

	2010			2009			2008		
	Canada	U.S.	Total	Canada	U.S.	Total	Canada	U.S.	Total
Revenue	**$ 217.6**	**$ 314.8**	**$ 532.4**	$ 263.8	$ 322.7	$ 586.5	$ 159.2	$ 340.1	$ 499.3

	As at December 31, 2010			As at December 31, 2009			As at December 31, 2008		
	Canada	U.S.	Total	Canada	U.S.	Total	Canada	U.S.	Total
Assets									
PP&E	**$ 502.2**	**$ 491.9**	**$ 994.1**	$ 534.5	$ 530.2	$ 1,064.7	$ 559.3	$ 546.7	$ 1,106.0
PPAs	**33.6**	**256.4**	**290.0**	36.6	293.8	330.4	39.7	368.9	408.6
Goodwill		**45.0**	**45.0**		47.6	47.6		55.1	55.1
Other assets		**62.8**	**62.8**		58.5	58.5		64.4	64.4
	$ 535.8	**$ 856.1**	**$ 1,391.9**	$ 571.1	$ 930.1	$ 1,501.2	$ 599.0	$ 1,035.1	$ 1,634.1

Note 23. Commitments

As of December 31, 2010 the Partnership's future purchase obligations were estimated as follows, based on existing contract terms and estimated inflation.

	2011	2012	2013	2014	2015	Later years	Total payments
Natural gas purchase contracts	$ 51.9	$ 53.7	$ 43.9	$ 47.2	$ 50.7	$ 53.6	$ 301.0
Natural gas transportation contracts	12.9	10.4	10.6	10.2	7.6	15.6	67.3
Operating and maintenance contracts	27.5	28.1	28.6	29.2	29.8	46.0	189.2

The North Bay, Kapuskasing and Nipigon plants operate under fixed long-term natural gas supply contracts and natural gas transportation contracts with built-in annual escalators. Expiry dates for the contracts vary with an average remaining contract life of six years as at December 31, 2010. The remaining fuel requirements, which account for approximately 2% of the power plants' fuel costs, are purchased at current market prices. Morris operates under a long-term natural gas transportation contract expiring in 2013.

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Capital Power Income L.P.

Notes to the Consolidated Financial Statements (Continued)

Note 23. Commitments (Continued)

The operating and maintenance contracts with the Manager are based on fixed fees escalated annually by inflation and have expiry terms of June 30, 2017.

Note 24. Morris acquisition

On October 31, 2008, the Partnership acquired 100% of the equity interest in Morris Cogeneration LLC (Morris), a combined heat and power facility in Illinois. The total purchase price was $90.7 million including $88.4 million (US$73.4 million) in cash plus acquisition costs of approximately $2.3 million.

The financial results of Morris are included in the Partnership's consolidated statements of income and loss from the date of acquisition. The purchase price for the acquisition of Morris was allocated to the assets acquired and liabilities assumed based on their estimated fair values as follows:

Current assets excluding cash and derivative instruments assets	$ 9.9
Derivative instruments assets current	0.7
Derivative instruments assets long term	2.9
Property, plant and equipment	87.2
Power purchase arrangements	2.1
Other assets	1.5
Current liabilities	(6.6)
Asset retirement obligations	(5.9)
Contract liabilities	(1.1)
Fair value of net assets acquired	$ 90.7
Consideration	
Cash	$ 88.4
Acquisition costs	2.3
	$ 90.7

Note 25. Discontinued operations

The Partnership completed the sale of its Castleton facility (Castleton) on May 26, 2009. The disposition of Castleton resulted in proceeds of $11.9 million (US$10.7 million) less transaction costs of

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Capital Power Income L.P.

Notes to the Consolidated Financial Statements (Continued)

Note 25. Discontinued operations (Continued)

$0.2 million (US$0.2 million) and a pre-tax accounting gain of $2.4 million. Revenues and expenses of Castleton were as follows:

	2009	2008
	(millions of dollars)	
Revenues	**$ 2.1**	$ 12.9
Expenses		
Cost of fuel	**2.1**	6.5
Operating and maintenance expense	**2.1**	4.4
Depreciation and amortization		3.7
Foreign exchange gains		(0.2)
Loss from operations	**(2.1)**	(1.5)
Gain on sale of Castleton	**2.4**	
Income (loss) before income tax	**0.3**	(1.5)
Income tax expense (recovery)	**0.5**	(0.8)
Loss from discontinued operations	**$ (0.2)**	$ (0.7)

The carrying amounts of the assets and liabilities of the discontinued operations at December 31, 2009 and December 31, 2008 were as follows:

	2009	2008
Assets of the discontinued operations		
Accounts receivable	$	$ 0.7
Inventories		1.0
Prepaids and other		0.6
Current assets of the discontinued operations		2.3
Property, plant and equipment		11.2
Future income taxes		0.8
Long-term assets of the discontinued operations		12.0
Total assets of the discontinued operations	$	$ 14.3
Liabilities of the discontinued operations		
Accounts payable	$	$ 1.2
Asset retirement obligations		2.1
Future income taxes		2.1
Long-term liabilities of the discontinued operations		4.2

Total liabilities of the discontinued operations	$	$	5.4

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Capital Power Income L.P.

Notes to the Consolidated Financial Statements (Continued)

Note 26. Comparative figures

Certain comparative figures have been reclassified to conform to the current year's presentation. The Partnership made an immaterial adjustment to the 2009 financial statements to reflect the reclassification of $5.2 million of costs from property, plant and equipment to inventory and to correspondingly decrease cash flow from operating activities and decrease cash flow used in investing activities. There was no impact to net earnings resulting from this adjustment.

Note 27. Canadian and U.S. accounting policy differences

The consolidated financial statements of the Partnership have been prepared in accordance with Canadian GAAP which differs in some respects from U.S. GAAP. Differences in accounting principles as they pertain to the consolidated financial statements are immaterial except as described below.

The application of U.S. GAAP would have the following effect on income and comprehensive loss as reported for the years ended December 31, 2010 and 2009:

	2010	2009
Net income in accordance with Canadian GAAP	**$ 30.5**	$ 57.6
Preferred share dividends	**14.1**	7.9
Change in effective portion of hedging derivatives[a]	**3.9**	(2.1)
Net income in accordance with U.S. GAAP	**48.5**	63.4
Attributable to:		
Equity holders of the Partnership	**34.4**	55.5
Preferred share dividends of a subsidiary company	**14.1**	7.9
	$ 48.5	$ 63.4
Other comprehensive loss in accordance with Canadian GAAP	**$ (72.4)**	$ (72.7)
Change in effective portion of hedging derivatives[a]	**(3.9)**	2.1
Other comprehensive loss in accordance with U.S. GAAP	**$ (76.3)**	$ (70.6)
Attributable to:		
Equity holders of the Partnership	**(90.4)**	(78.5)
Preferred share dividends of a subsidiary company	**14.1**	7.9
	$ (76.3)	$ (70.6)
Net income per unit in accordance with U.S. GAAP basic and diluted	**$ 0.63**	$ 1.03

(a) Accounting standards under U.S. GAAP requires the measurement of hedge effectiveness incorporate the credit risk of the Partnership or its counterparty. Canadian GAAP does not have a similar requirement which results in changes in the effective portion of the hedging derivatives.

Capital Power Income L.P.

Notes to the Consolidated Financial Statements (Continued)

Note 27. Canadian and U.S. accounting policy differences (Continued)

The application of U.S. GAAP would have the following effect on the consolidated balance sheets as reported at December 31, 2010 and 2009:

	2010		2009	
	Canadian GAAP	U.S. GAAP	Canadian GAAP	U.S. GAAP
Current assets	**$ 121.0**	**$ 121.0**	$ 100.1	$ 100.1
Long-term assets[b]	**1,462.8**	**1,467.2**	1,568.0	1,573.0
Current liabilities	**82.2**	**82.2**	75.6	75.6
Long term liabilities[b]	**874.2**	**878.6**	853.3	858.3
Partners' equity and preferred shares[c]	**627.4**	**627.4**	739.2	739.2

(b) Under Canadian GAAP, deferred financing fees are presented in the consolidated balance sheet as a reduction of the debt balance, while under U.S. GAAP, deferred financing fees are presented as other assets.

(c) Under Canadian GAAP, the preferred shares issued by a subsidiary company are classified between liabilities and equity, while under U.S. GAAP, they are classified in equity attributed to non-controlling interests.

U.S. GAAP requires the Partnership's investment in a joint venture to be accounted for using the equity method. However, under an accommodation of the Securities and Exchange Commission, accounting for joint ventures needs not be reconciled from Canadian to U.S. GAAP. The different accounting treatment affects only display and classification and not earnings or partners' equity.

Under U.S. GAAP, no sub-total would be provided in the operating section of the consolidated statement of cash flows. As well, under U.S. GAAP, reconciliation in the consolidated statement of cash flows would commence with net income instead of income of continuing operation. However, there are no differences in the total operating, investing and financing cash flows.

Note 28. Subsequent event

On June 20, 2011, the Partnership and Atlantic Power Corporation (Atlantic Power) jointly announced that they have entered into an arrangement agreement to which Atlantic Power would acquire, directly and indirectly, all of the outstanding limited partnership units of the Partnership for $19.40 per limited partnership unit, payable in cash or shares of Atlantic Power (the "Transaction"). The Transaction is expected to be completed in the fourth quarter of 2011, subject to customary approvals including unitholder and shareholder approvals

In connection with Atlantic Power's acquisition of the Partnership, the Partnership will sell Roxboro and Southport to an affiliate of CPC. The Transaction values the Southport and Roxboro at approximately $121 million. This Transaction will have the effect of reducing the number of Partnership units outstanding by approximately 6.2 million units.

Additionally, in connection with the Transaction, the management agreement between CPC and the Partnership will be terminated (or assigned to Atlantic Power). Atlantic Power will assume the management of the Partnership.

Capital Power Income L.P.

CONDENSED INTERIM CONSOLIDATED STATEMENTS OF INCOME (LOSS)

(unaudited) (In millions of Canadian dollars except units and per unit amounts)	Three months ended June 30 2011	 2010 Restated (Note 7)	Six months ended June 30 2011	 2010 Restated (Note 7)
Revenues	**$ 130.3**	$ 97.3	**$ 261.5**	$ 241.5
Cost of fuel	**53.2**	47.0	**109.5**	116.9
Operating and maintenance expense	**27.6**	24.2	**52.4**	46.8
	49.5	26.1	**99.6**	77.8
Other costs (income)				
Depreciation	**22.5**	24.5	**45.5**	47.9
Administrative and other expenses	**9.6**	1.6	**13.8**	5.6
Finance costs (Note 4)	**10.6**	10.0	**21.5**	21.4
Finance income		(1.8)		(1.8)
Income (loss) before income tax	**6.8**	(8.2)	**18.8**	4.7
Income tax expense (recovery)	**1.1**	(7.3)	**1.2**	(10.9)
Net income (loss)	**$ 5.7**	$ (0.9)	**$ 17.6**	$ 15.6
Attributable to:				
Equity holders of the Partnership	**2.1**	(4.5)	**10.5**	8.4
Preferred share dividends of a subsidiary company	**3.6**	3.6	**7.1**	7.2
	$ 5.7	$ (0.9)	**$ 17.6**	$ 15.6
Income (loss) per unit attributable to the equity holders of the Partnership (basic and diluted)	**$ 0.04**	$ (0.08)	**$ 0.19**	$ 0.15
Weighted average units outstanding (millions)	**56.4**	54.7	**56.2**	54.5

See accompanying notes to the condensed interim consolidated financial statements.

Capital Power Income L.P.

CONDENSED INTERIM CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME (LOSS)

(unaudited) (In millions of Canadian dollars)	Three months ended June 30 2011	Three months ended June 30 2010 Restated (Note 7)	Six months ended June 30 2011	Six months ended June 30 2010 Restated (Note 7)
Income (loss) for the period	**$ 5.7**	$ (0.9)	**$ 17.6**	$ 15.6
Other comprehensive income (loss), net of income tax Cash flow hedges:				
Amortization of deferred gains on derivative instruments de-designated as cash flow hedges to income[(1)]	**(0.1)**	(0.1)	**(0.2)**	(0.2)
Unrealized gains (losses) on derivative instruments designated as cash flow hedges[(2)]	**(4.9)**	4.1	**(0.2)**	(24.8)
Ineffective portion of cash flow hedges reclassified to income for the period[(3)]	**0.1**	1.4	**1.3**	0.8
Net investment in foreign operations:				
Gain (loss) on translating investment in foreign operations[(4)]	**(2.6)**	25.5	**(14.2)**	7.0
Available for sale financial asset:				
Net change in fair value of investment[(5)]	**1.0**	0.5	**0.9**	2.1
	(6.5)	31.4	**(12.4)**	(15.1)
Total comprehensive income (loss) for the period:	**$ (0.8)**	$ 30.5	**$ 5.2**	$ 0.5
Attributable to:				
Equity holders of the Partnership	**$ (4.4)**	$ 26.9	**$ (1.9)**	$ (6.7)
Preferred share dividends of a subsidiary company	**3.6**	3.6	**7.1**	7.2

(1) Net of income tax expense of $nil million and $nil million (2010 $nil and $nil) for the three and six months ended June 30, 2011.

(2) Net of income tax recovery of $1.7 million and $0.1 million (2010 $0.3 million and income tax recovery of $6.2 million) for the three and six months ended June 30, 2011.

(3) Net of income tax expense of $0.1 million and $0.4 million (2010 $nil and $nil) for the three and six months ended June 30, 2011.

(4) Includes income tax expense of $0.1 million and $0.8 million (2010 income tax recovery of $2.1 million and $0.4 million) for the three and six months ended June 30, 2011.

(5) Net of income tax expense of $0.5 million and $0.5 million (2010 $0.3 million and $0.6 million) for the three and six months ended June 30, 2011.

See accompanying notes to the condensed interim consolidated financial statements.

Capital Power Income L.P.

CONDENSED INTERIM CONSOLIDATED STATEMENTS OF FINANCIAL POSITION

(unaudited) (In millions of Canadian dollars)	June 30, 2011	December 31, 2010 Restated (Note 7)
ASSETS		
Current assets		
Cash and cash equivalents	**$ 12.8**	$ 27.5
Trade and other receivables	**48.8**	52.5
Inventories	**11.4**	19.5
Prepaids and other	**6.8**	4.0
Derivative assets (Note 3)	**13.0**	10.4
Assets classified as held for sale (Note 2)	**130.6**	
Total current assets	**223.4**	113.9
Non-current assets		
Derivative assets (Note 3)	**32.7**	29.7
Other financial assets	**69.4**	72.5
Deferred tax asset	**20.3**	38.4
Intangible assets	**270.4**	290.1
Property, plant and equipment	**835.9**	958.5
Goodwill	**19.7**	43.8
Total non-current assets	**1,248.4**	1,433.0
Total assets	**$ 1,471.8**	$ 1,546.9
LIABILITIES AND PARTNERS' EQUITY		
Liabilities		
Trade and other payables	**$ 59.4**	$ 61.5
Derivative liabilities (Note 3)	**23.1**	21.1
Liabilities classified as held for sale (Note 2)	**15.4**	
Total current liabilities	**97.9**	82.6
Non-current liabilities		
Derivative liabilities (Note 3)	**79.7**	81.9
Loans and borrowings	**675.5**	704.5
Deferred tax liabilities	**17.2**	30.1
Decommissioning provision	**39.6**	50.1
Other liabilities	**9.5**	7.8
Total non-current liabilities	**821.5**	874.4
Total liabilities	**919.4**	957.0
Equity attributable to equity holders of the Partnership		
Partners' capital	**1,241.6**	1,227.6
Deficit	**(821.9)**	(782.9)
Accumulated other comprehensive loss	**(87.5)**	(75.1)
	332.2	369.6
Preferred shares issued by a subsidiary company	**220.2**	220.3

Total equity		**552.4**		589.9
Contingencies (Note 6)				
Total liabilities and equity	**$**	**1,471.8**	$	1,546.9

See accompanying notes to the condensed interim consolidated financial statements.

Capital Power Income L.P.

CONDENSED INTERIM CONSOLIDATED STATEMENTS OF CHANGES IN PARTNERS' EQUITY

(unaudited) (in millions of Canadian dollars)	Partnership capital	Cumulative translation account*	Available for sale financial assets*	Cash flow hedges*	Deficit	Equity attributable to the Partnership	Non-controlling interests**	Total
Equity as at January 1, 2011	$ 1,227.6	$ (29.6)	$ 6.8	$ (52.3)	$ (782.9)	$ 369.6	$ 220.3	$ 589.9
Income for the period					10.5	10.5	7.1	17.6
Other comprehensive income (loss):								
Amortization of deferred gains on de-designated cash flow hedges				(0.2)		(0.2)		(0.2)
Unrealized gains on derivative instruments designated as cash flow hedges				(0.2)		(0.2)		(0.2)
Ineffective portion of cash flow hedges reclassified to income for the period				1.3		1.3		1.3
Loss on translating investment in foreign operations		(14.2)				(14.2)		(14.2)
Net change in fair value of investment			0.9			0.9		0.9
Total comprehensive income (loss)		(14.2)	0.9	0.9	10.5	(1.9)	7.1	5.2
Distributions					(49.5)	(49.5)		(49.5)
Preferred share dividends paid							(6.5)	(6.5)
Tax on preferred share dividends							(0.7)	(0.7)
Issue of Partnership units	14.0					14.0		14.0
Equity as at June 30, 2011	$ 1,241.6	$ (43.8)	$ 7.7	$ (51.4)	$ (821.9)	$ 332.2	$ 220.2	$ 552.4

See accompanying notes to the condensed interim consolidated financial statements.

Capital Power Income L.P.

CONDENSED INTERIM CONSOLIDATED STATEMENTS OF CHANGES IN PARTNERS' EQUITY (Continued)

(unaudited) **(in millions of Canadian dollars)** **Restated (Note 7)**	**Partnership capital**	**Cumulative translation account***	**Available for sale financial assets***	**Cash flow hedges***	**Retained earnings**	**Equity attributable to the Partnership**	**Non-controlling interests****	**Total**
Equity as at January 1, 2010	$ 1,200.6	$	$ (2.2)	$ (3.4)	$ (687.5)	$ 507.5	$ 220.7	$ 728.2
Income for the period					8.4	8.4	7.2	15.6
Other comprehensive income (loss)								
Amortization of deferred gains on de-designated cash flow hedges				(0.2)		(0.2)		(0.2)
Unrealized losses on derivative instruments designated as cash flow hedges				(24.8)		(24.8)		(24.8)
Ineffective portion of cash flow hedges reclassified to income for the period				0.8		0.8		0.8
Loss on translating investment in foreign operations		7.0				7.0		7.0
Net change in fair value of investment			2.1			2.1		2.1
Total comprehensive income (loss)		7.0	2.1	(24.2)	8.4	(6.7)	7.2	0.5
Distributions					(48.1)	(48.1)		(48.1)
Preferred share dividends paid							(6.5)	(6.5)
Tax on preferred share dividends							(0.9)	(0.9)
Issue of Partnership units	13.5					13.5		13.5
Equity as at June 30, 2010	$ 1,214.1	$ 7.0	$ (0.1)	$ (27.6)	$ (727.2)	$ 466.2	$ 220.5	$ 686.7

* Accumulated other comprehensive loss

** Preferred share dividends of a subsidiary company

See accompanying notes to the condensed interim consolidated financial statements.

Capital Power Income L.P.

CONDENSED INTERIM CONSOLIDATED STATEMENTS OF CASH FLOWS

(unaudited)	Six months ended June 30 2011	2010 Restated
(In millions of Canadian dollars)		**(Note 7)**
Operating activities		
Income before income tax for the period	**$ 18.8**	$ 4.7
Adjustments:		
Depreciation	**45.5**	47.9
Fair value changes on derivative instruments	**(4.7)**	20.5
Preferred share dividends paid	**(6.5)**	(6.5)
Principal repayments on finance lease receivable	**1.1**	0.9
Deferred revenue	**1.2**	1.6
Income taxes paid	**(3.1)**	(3.0)
Interest expense	**19.4**	19.3
Interest income		(1.8)
Interest paid	**(19.8)**	(19.3)
Other	**1.6**	0.8
	53.5	65.1
Decrease in operating working capital	**(0.9)**	(20.2)
Cash provided by operating activities	**52.6**	44.9
Investing activities		
Additions to property, plant and equipment	**(13.3)**	(12.8)
Change in non-operating working capital	**(1.1)**	(4.0)
Cash used in investing activities	**(14.4)**	(16.8)
Financing activities		
Distributions paid	**(35.4)**	(34.5)
Net borrowings (repayments) under credit facilities	**(16.8)**	8.5
Repayment of loans and borrowings		(0.7)
Cash used in financing activities	**(52.2)**	(26.7)
Foreign exchange (losses) gains on cash held in a foreign currency	**(0.7)**	0.2
Decrease in cash and cash equivalents	**(14.7)**	1.6
Cash and cash equivalents, beginning of period	**27.5**	9.5
Cash and cash equivalents, end of period	**$ 12.8**	$ 11.1

See accompanying notes to the condensed interim consolidated financial statements.

Capital Power Income L.P.

Notes to the Condensed Interim Consolidated Financial Statements

June 30, 2011

(Unaudited, tabular amounts in millions of Canadian dollars)

1. Basis of presentation and conversion to IFRS

These condensed interim consolidated financial statements have been prepared by management of the General Partner in accordance with International Financial Reporting Standards (IFRS) International Accounting Standard (IAS) 34 Interim Financial Reporting as issued by the International Accounting Standards Board and adopted by the Canadian Institute of Chartered Accountants applicable companies for years beginning on or after January 1, 2011. For prior reporting periods up to and including the year ended December 31, 2010, the Partnership prepared its condensed interim consolidated financial statements in accordance with Canadian generally accepted accounting principles (GAAP). The condensed consolidated interim financial statements do not include all of the information required for full annual financial statements.

An explanation of how the transition to IFRS has affected the financial position, financial performance and cash flows of the Partnership is provided in note 7. This note includes reconciliations of equity and total comprehensive income for comparative periods reported under previous Canadian GAAP to those reported under IFRSs. A reconciliation of equity at the date of transition reported under previous Canadian GAAP to equity reported under IFRSs is included in the condensed interim consolidated financial statements for the first quarter of 2011.

The Partnership's condensed interim consolidated financial statements are prepared under the historical cost convention, except for the revaluation of the Partnership's derivative instruments, cash and available for sale financial assets, which are recognized at fair value and certain property, plant and equipment which is recognized at deemed cost as fair value, at January 1, 2010.

Quarterly revenues, income and cash provided by operating activities are affected by seasonal contract pricing, seasonal weather conditions, fluctuations in United States (US) dollar exchange rates, fulfillment of firm energy requirements, natural gas prices, waste heat availability and planned and unplanned plant outages, as well as items outside of the normal course of operations. Quarterly income is also affected by unrealized foreign exchange gains and losses and fair value changes in derivative instruments. The California plants normally generate the majority of their operating margin during the summer months when the plants can earn performance bonuses. Additionally, the plants located on Naval bases earn approximately 75% of their capacity revenue during these months. Revenues, income and cash provided by operating activities from the Partnership's Ontario plants are generally higher in the winter months (October to March) and lower in the summer months (April to September) due to seasonal pricing under the power purchase arrangements. Revenues and income from the Partnership's hydroelectric plants are generally higher in the spring months due to seasonally higher water flows.

Use of judgements and estimates

The preparation of the Partnership's condensed interim consolidated financial statements in accordance with IFRS requires management to make judgements, estimates and assumptions that affect the reported amounts of income, expenses, assets and liabilities as well as the disclosure of contingent assets and liabilities at the date of the condensed interim consolidated financial statements.

The Partnership reviews its estimates and assumptions on an ongoing basis and uses the most current information available and exercises careful judgement in making these estimates and

Capital Power Income L.P.

Notes to the Condensed Interim Consolidated Financial Statements (Continued)

June 30, 2011

(Unaudited, tabular amounts in millions of Canadian dollars)

1. Basis of presentation and conversion to IFRS (Continued)

assumptions. Adjustments to previous estimates, which may be material, will be recorded in the period they become known. Actual results may differ from these estimates.

In the opinion of management of the Partnership's General Partner, these condensed interim consolidated financial statements have been properly prepared within reasonable limits of materiality and within the framework of the Partnership's accounting policies.

Future accounting standards

A number of new standards, and amendments to standards and interpretations, are not yet effective for the quarter ended June 30, 2011 and have not been applied in preparing the unaudited condensed interim consolidated financial statements. The following standards and interpretations have been issued by the International Accounting Standards Board and the International Financial Reporting Interpretations Committees with effective dates relating to the annual periods starting on or after the effective dates as follows:

International Accounting Standards (IAS/IFRS)	Effective Date
IFRS 9 Financial Instruments	January 1, 2013
IAS 12 Income Taxes	January 1, 2012
IFRS 10 Consolidated Financial Statements	January 1, 2013
IFRS 11 Joint Arrangements	January 1, 2013
IFRS 12 Disclosures of Interests in Other Entities	January 1, 2013
IFRS 13 Fair Value Measurement	January 1, 2013
IAS 1 Presentation of Financial Statements	July 1, 2012

IFRS 9 applies to the classification and measurement of financial assets and financial liabilities. It is the first of three phases of a project to develop standards to replace IAS 39 Financial Instruments and was initiated in response to the crisis in financial markets.

The amendments to IAS 12 relate to the measurement of deferred taxes for investment property, PP&E and intangible assets carried at fair value.

IFRS 10 replaces IAS 27 Consolidated and Separate Financial Statements and SIC 12 Consolidation Special Purpose Entities. IFRS 10 establishes principles for the presentation and preparation of consolidated financial statements. It provides a single consolidation model that identifies control as the basis for consolidation for all types of entities. IFRS 12 provides comprehensive disclosure requirements for all forms of interests in other entities, including subsidiaries, joint arrangements, associates and special purpose vehicles.

IFRS 11 supersedes IAS 31 Interests in Joint Ventures and SIC 13 Jointly Controlled Entities Non-Monetary Contributions by Venturers. The standard requires a single method to account

Capital Power Income L.P.

Notes to the Condensed Interim Consolidated Financial Statements (Continued)

June 30, 2011

(Unaudited, tabular amounts in millions of Canadian dollars)

1. Basis of presentation and conversion to IFRS (Continued)

for interests in jointly controlled entities. All joint ventures are required to be recognized as an investment and be accounted for on an equity basis.

IFRS 13 defines fair value, sets out in a single IFRS a framework for measuring fair value and requires disclosures about fair value measurements. IFRS 13 applies when other IFRSs require or permit fair value measurements. It does not introduce any new requirements to measure an asset or a liability at fair value, change what is measured at fair value in IFRSs or address how to present changes in fair value.

The amendments to IAS 1 provide improvements to the presentation of components of other comprehensive income. It requires entities to group items within other comprehensive income that may be reclassified to profit or loss.

The extent of the impact of adoption of these standards and interpretations on the consolidated financial statements of the Partnership has not been determined.

2. Assets and liabilities held for sale

On June 20, 2011 the Partnership agreed to sell its Southport and Roxboro facilities (the disposal group) to an affiliate of Capital Power Corporation for approximately $121 million concurrent with and contingent upon the sale of the Partnership to Atlantic Power Corporation. The sale is expected to close in the fourth quarter of 2011. The Partnership will not have any continuing involvement in the disposal group after the disposal transaction. Accordingly, the assets and liabilities of the disposal group at June 30, 2011 have been segregated and presented as assets and liabilities held for sale as follows:

	June 30, 2011
Assets held for sale	
Accounts receivable	$ 6.0
Inventories	7.3
Prepaids and other	
Property, plant and equipment	90.5
Deferred taxes	4.0
Goodwill	22.8
	$ 130.6
Liabilities held for sale	
Accounts payable	$ 3.0
Decommissioning provision	12.0
Deferred taxes	
Other liabilities	0.4
	$ 15.4

Capital Power Income L.P.

Notes to the Condensed Interim Consolidated Financial Statements (Continued)

June 30, 2011

(Unaudited, tabular amounts in millions of Canadian dollars)

2. Assets and liabilities held for sale (Continued)

No impairment loss was recognized in the condensed statement of comprehensive income for the three and six months ended June 30, 2011 as the carrying amount of the disposal group is less than its fair value less cost to sell.

At June 30, 2011, accumulated other comprehensive loss included accumulated foreign exchange losses of $9.4 million related to the Partnership's investment in the disposal group that will be reclassified to net income (loss) on disposal.

3. Derivative instruments

Derivative instruments are held to manage financial risk related to energy procurement and treasury management. All derivative instruments, including embedded derivatives, are classified as held at fair value through profit or loss and are recorded at fair value on the statement of financial position as derivative instruments assets and derivative instruments liabilities unless exempted from derivative treatment as a normal purchase, sale or usage. All changes in their fair value are recorded in the condensed interim consolidated statement of income.

The derivative instruments assets and liabilities used for risk management purposes consist of the following:

	June 30, 2011			
	Natural gas		Foreign exchange	
	Hedges	Non-hedges	Non-hedges	Total
Derivative instruments assets:				
Current	$	$	$ 13.0	$ 13.0
Non-current		0.2	32.5	32.7
Derivative instruments liabilities:				
Current	(17.8)	(1.9)	(3.4)	(23.1)
Non-current	(74.6)	(0.2)	(4.9)	(79.7)
	$ (92.4)	$ (1.9)	$ 37.2	$ (57.1)
Net notional amounts:				
Gigajoules (GJs)(millions)	34.7	4.4		
US foreign exchange (US dollars in millions)			297.3	
Contract terms (years)	5.5	0.3 to 1.5	0.2 to 5.0	

Capital Power Income L.P.

Notes to the Condensed Interim Consolidated Financial Statements (Continued)

June 30, 2011

(Unaudited, tabular amounts in millions of Canadian dollars)

3. Derivative instruments (Continued)

	December 31, 2010			
	Natural gas		Foreign exchange	
	Hedges	Non-hedges	Non-hedges	Total
Derivative instruments assets:				
Current	$	$	$ 10.4	$ 10.4
Non-current			29.7	29.7
Derivative instruments liabilities:				
Current	(16.2)	(3.0)	(1.9)	(21.1)
Non-current	(76.9)		(5.0)	(81.9)
	$ (93.1)	$ (3.0)	$ 33.2	$ (62.9)
Net notional amounts:				
Gigajoules (GJs)(millions)	37.8	6.5		
US foreign exchange (US dollars in millions)			309.0	
Contract terms (years)	6.0	0.8 to 2.0	0.2 to 5.5	

Unrealized and realized pre-tax gains and losses on derivative instruments recognized in the condensed interim consolidated statement of income and other comprehensive income were:

	Financial statement category	Three months ended June 30		Six months ended June 30	
		2011	2010	**2011**	2010
Foreign exchange non-hedges	Revenue	**$ 3.1**	$ (18.6)	**$ 10.3**	$ (10.0)
Natural gas non-hedges	Cost of fuel	**1.3**	2.4	**2.0**	(5.9)
Natural gas hedges ineffective portion	Cost of fuel	**(0.5)**	(1.4)	**(1.7)**	(0.8)
Natural gas hedges effective portion	Other comprehensive income (loss)	**(6.7)**	5.8	**1.1**	(30.2)

The Partnership has elected to apply hedge accounting on certain derivative instruments it uses to manage commodity price risk relating to natural gas prices. For the three and six months ended June 30, 2011, the change in the fair value of the ineffective portion of hedging derivatives required to be recognized in the condensed interim consolidated statement of income was $0.5 million and $1.7 million respectively.

Capital Power Income L.P.

Notes to the Condensed Interim Consolidated Financial Statements (Continued)

June 30, 2011

(Unaudited, tabular amounts in millions of Canadian dollars)

3. Derivative instruments (Continued)

Net after tax gains and losses on derivative instruments designated as cash flow hedges are included in accumulated other comprehensive income at June 30, 2011. Losses of $51.4 million are expected to settle and be reclassified to the condensed interim consolidated statement of income in the following periods:

	June 30, 2011
Within one year	**$ (11.4)**
Between 1 to 5 years	**(36.2)**
After more than 5 years	**(3.8)**
	$ (51.4)

The Partnership's cash flow hedges extend up to 2016.

4. Finance costs

	Three months ended June 30		Six months ended June 30	
	2011	**2010**	**2011**	**2010**
Interest on long-term debt	**$ 9.5**	$ 9.7	**$ 19.1**	$ 19.3
Foreign exchange losses		(0.5)		0.2
Accretion and amortization	**0.7**	0.6	**1.2**	1.3
Other	**0.4**	0.2	**1.2**	0.6
	$ 10.6	$ 10.0	**$ 21.5**	$ 21.4

5. Segment information

The Partnership operates in one reportable business segment involved in the operation of electrical generation plants within British Columbia, Ontario and in the US in California, Colorado, Illinois, New Jersey, New York, North Carolina and Washington State.

Geographic information

	Three months ended June 30, 2011			Three months ended June 30, 2010		
	Canada	**US**	**Total**	**Canada**	**US**	**Total**
Revenue	**$ 51.3**	**$ 79.0**	**$ 130.3**	$ 29.3	$ 68.0	$ 97.3

	Six months ended June 30, 2011			Six months ended June 30, 2010		
	Canada	**US**	**Total**	**Canada**	**US**	**Total**
Revenue	**$ 116.0**	**$ 145.5**	**$ 261.5**	$ 97.2	$ 144.3	$ 241.5

Capital Power Income L.P.

Notes to the Condensed Interim Consolidated Financial Statements (Continued)

June 30, 2011

(Unaudited, tabular amounts in millions of Canadian dollars)

5. Segment information (Continued)

	As at June 30, 2011			As at December 31, 2010		
	Canada	US	Total	Canada	US	Total
Assets						
PP&E	**$ 436.7**	**$ 399.2**	**$ 835.9**	$ 448.5	$ 510.0	$ 958.5
Goodwill		**19.7**	**19.7**		43.8	43.8
Intangible assets	**32.1**	**238.3**	**270.4**	33.6	256.5	290.1
	$ 468.8	**$ 657.2**	**$ 1,126.0**	$ 482.1	$ 810.3	$ 1,292.4

	Six months ended June 30, 2011			Six months ended June 30, 2010		
	Canada	US	Total	Canada	US	Total
Capital additions	**$ 4.4**	**$ 8.9**	**$ 13.3**	$ 4.9	$ 7.9	$ 12.8

6. Contingencies

The Partnership and Atlantic Power Corporation (Atlantic Power) have entered into an agreement pursuant to which Atlantic Power would acquire, directly and indirectly, all of the outstanding limited partnership units of the Partnership (the "Transaction"). If the Transaction fails to receive unitholder approval, the Partnership will reimburse Atlantic Power for its costs associated with the Transaction up to $8 million. Further, any solicitation or recommendation of a competing proposal or offer prior to completion of this agreement will result in the payment of a $35 million termination fee. There is no possibility of any reimbursement of these amounts once paid.

Concurrent with and contingent upon the completion of the Transaction, the Partnership will pay $8.5 million to affiliates of Capital Power Corporation for the termination of certain management and operations agreements and will pay success fees of approximately $12 million to its financial advisors.

7. Transition to IFRS

For all periods up to and including the year ended December 31, 2010, the Partnership prepared its financial statements in accordance with previous Canadian GAAP.

The Partnership has prepared financial statements which comply with IFRS applicable for periods beginning on or after January 1, 2010 as described in note 2. In preparing these financial statements, the Partnership's opening statement of financial position was prepared as at January 1, 2010, the Partnership's date of transition to IFRS. This note explains the principal adjustments made by the Partnership in restating its previously published Canadian GAAP financial statements for the three and six months ended June 30, 2010. Explanations of the principal adjustments made by the Partnership in restating its Canadian GAAP Statement of Financial Position as at January 1, 2010 and its financial statements for the twelve months ended December 31, 2010 are included in the condensed

Capital Power Income L.P.

Notes to the Condensed Interim Consolidated Financial Statements (Continued)

June 30, 2011

(Unaudited, tabular amounts in millions of Canadian dollars)

7. Transition to IFRS (Continued)

interim consolidated financial statements for the first quarter of 2011. The Partnership has applied the following optional exemptions in its transition from Canadian GAAP to IFRS:

Business combinations

IFRS 1 provides the option to apply IFRS 3, Business Combinations, retrospectively or prospectively from the date of transition. The Partnership has taken the IFRS 1 election to not restate previous business combinations at the date of transition. Goodwill arising on such business combinations before the date of transition has not been adjusted from its carrying value previously reported.

Translation of foreign operations

The Partnership has elected the option available under IFRS 1, to deem the cumulative translation account for all foreign operations to be $nil at the date of transition, and to reclassify all amounts determined in accordance with previous GAAP at that date to retained earnings.

Decommissioning liabilities

IFRS 1 provides an optional election to adopt a simplified approach, whereby the Partnership can elect to not calculate retrospectively the effect of each change in estimate that occurred prior to the date of transition. The Partnership has elected to use the simplified approach.

Fair value as deemed cost

IFRS 1 also provides an optional election on transition to IFRS which allows the use of fair value as deemed cost on items of property, plant and equipment. The Partnership has elected under IFRS 1 to fair value certain items of property, plant and equipment.

Capital Power Income L.P.

Notes to the Condensed Interim Consolidated Financial Statements (Continued)

June 30, 2011

(Unaudited, tabular amounts in millions of Canadian dollars)

7. Transition to IFRS (Continued)

Reconciliation of equity

Reconciliation of equity June 30, 2010

	Canadian GAAP	IAS 16 and 37 (a)	IAS 36 (b)	IFRS 1 (c)	Other impacts (d)	Presentation adjustment	IFRS
ASSETS							
Current assets							
Cash and cash equivalents	$ 11.1	$	$	$	$	$	$ 11.1
Trade and other receivables	67.1						67.1
Inventories	39.1						39.1
Prepaids and other	7.3						7.3
Future income tax asset	1.8					(1.8)	
Derivative assets	4.5						4.5
Total current assets	130.9					(1.8)	129.1
Non-current assets							
Derivative assets	19.6						19.6
Other financial assets	49.2				(0.2)	(1.1)	47.9
Deferred tax asset	41.1				(3.6)	1.8	39.3
Intangible assets	321.1		(0.9)			1.1	321.3
Property, plant and equipment	1,047.8	(20.6)	(21.3)	57.6			1,063.5
Goodwill	48.2		(1.2)				47.0
Total non-current assets	1,527.0	(20.6)	(23.4)	57.6	(3.8)	1.8	1,538.6
Total assets	$ 1,657.9	$ (20.6)	$ (23.4)	$ 57.6	$ (3.8)	$	$ 1,667.7
LIABILITIES AND PARTNERS' EQUITY							
Liabilities							
Trade and other payables	$ 64.8	$	$	$	$	$	64.8
Derivative liabilities	14.4						14.4
Future income tax liability	0.3					(0.3)	
Loans and borrowings	0.7						0.7
Total current liabilities	80.2					(0.3)	79.9
Non-current liabilities							
Derivative liabilities	60.4						60.4
Loans and borrowings	734.2						734.2
Decommissioning provision		21.1				29.5	50.6
Deferred tax liabilities	52.7				(4.3)	0.3	48.7
Other liabilities	36.6					(29.5)	7.1
Total non-current liabilities	883.9	21.1			(4.3)	0.3	901.0
Total liabilities	964.1	21.1			(4.3)		980.9

Equity attributable to equity holders of the Partnership							
Partners' capital	1,214.1						1,214.1
Deficit	(586.5)	(41.4)	(23.1)	(75.5)	(0.7)		(727.2)
Accumulated other comprehensive loss	(153.5)	(0.3)	(0.3)	133.1	0.4		(20.6)
	474.1	(41.7)	(23.4)	57.6	(0.3)		466.3
Preferred shares issued by a subsidiary company	219.7				0.8		220.5
Total equity	693.8	(41.7)	(23.4)	57.6	0.5		686.8
Total liabilities and equity	$ 1,657.9	$ (20.6)	$ (23.4)	$ 57.6	$ (3.8)	$	$ 1,667.7

Capital Power Income L.P.

Notes to the Condensed Interim Consolidated Financial Statements (Continued)

June 30, 2011

(Unaudited, tabular amounts in millions of Canadian dollars)

7. Transition to IFRS (Continued)

Notes to the equity reconciliations

a) IAS 16 Property, plant and equipment (PP&E) & IAS 37 provisions

IFRS are more specific with respect to the level at which component accounting is required and mandates that overhauls embedded within the initial carrying amount of a component must be treated as a separate component.

In accordance with IAS 16, PP&E has decreased by $36.3 million at June 30, 2010 as a result of identifying the significant components and calculating the adjustment to accumulated depreciation for the components' useful lives as well as derecognizing the overhauls that were inherent in the original turbines and a subsequent overhaul has been performed.

In accordance with IAS 37, provisions are required to be measured at the best estimate of the expected expenditure using discount rates appropriate for each liability. Under Canadian GAAP the provision was measured at fair value. The provision is to be re-measured at each reporting period for any changes in cash flow estimates, timing of decommissioning activity and discount rates. Accordingly, the Partnership re-measured its asset retirement obligations with revised discount rates for all decommissioning liabilities. The re-measurement of the decommissioning liabilities resulted in an increase of $21.1 million at June 30, 2010 to the non-current provision. The re-measurement of the decommissioning liability also resulted in an increase to the associated PP&E of $15.7 million at June 30, 2010.

These adjustments resulted in an increase to the deficit of $41.4 million at June 30, 2010.

Accumulated other comprehensive loss (AOCL) increased by $0.3 million at June 30, 2010 as a result of translating the IFRS adjustments for the Partnership's operations with a US dollar functional currency.

b) IAS 36 Impairment

In accordance with IAS 36, the Partnership reviewed the recoverable amount for its CGUs with allocated goodwill at both the date of transition and in the third quarter of 2010. IAS 36 also requires that impairment testing be done on a CGU level and requires that goodwill be allocated to the CGU level and included in the impairment test for each plant. The Partnership has determined its CGUs to be at the plant level. For these CGU's, management assessed whether there were any triggering events at December 31, 2010. The recoverable amounts were calculated on a fair value less cost to sell basis, using discounted cash flow models based on the Partnership's long term planning model. Previously under GAAP, the carrying values were compared to the undiscounted cash flows first and if the undiscounted cash flows exceeded carrying value then no further steps were taken.

As a result of the changes to the determination of recoverable amounts and the allocation of the goodwill to the CGUs, the Partnership recorded total impairments of $23.7 million at December 31, 2009, which includes $12.9 million for Roxboro and $8.0 million for Greeley. The impairments at Roxboro and Greeley were the result of weakening economic conditions in their respective markets.

Capital Power Income L.P.

Notes to the Condensed Interim Consolidated Financial Statements (Continued)

June 30, 2011

(Unaudited, tabular amounts in millions of Canadian dollars)

7. Transition to IFRS (Continued)

The Partnership decreased its intangible assets, PP&E and goodwill $0.9 million, $21.3 million and $1.2 million respectively at June 30, 2010.

These adjustments resulted in an increase to the deficit of $23.1 million at June 30, 2010.

AOCL decreased by $0.3 million at June 30, 2010 as a result of translating the IFRS adjustments for the Partnership's operations with a US dollar functional currency.

c) IFRS 1 First time adoption of IFRS

As a result of the Partnership taking the IFRS 1 election to use fair value as deemed cost for the PP&E at Manchief and Curtis Palmer, the PP&E balance increased by $57.6 million at June 30, 2010. The change in the value of the increase to fair value subsequent to January 1, 2010 is a result of depreciation of the increase to fair value and foreign exchange impacts. The aggregate fair value deemed as cost for the PP&E of these plants at January 1, 2010 was $210.2 million.

As a result of the Partnership taking the IFRS 1 election to deem the balance for the cumulative translation amount to be $nil on January 1, 2010, the accumulated other comprehensive loss decreased by $131.9 million.

These adjustments resulted in an increase to the deficit of $75.5 million at June 30, 2010.

AOCL decreased by $1.2 million at June 30, 2010 as a result of translating the fair value as deemed cost election taken by the Partnership's operations with a US dollar functional currency.

d) Other impacts

In accordance with IAS 39, Financial Instruments: Recognition and Measurement, financial assets available for sale must be measured at fair value. Under Canadian GAAP, the investment in PERH was carried at the lower of historic cost and fair value. IAS 39 requires financial assets to be measured at fair value even if it is not traded in an active market. Fair value was established using the market price of Primary Energy Recycling Corporation (PERC), a publicly traded company whose sole asset is an investment in PERH. As a result of measuring the investment in PERH at its fair value, other financial assets were reduced by $0.2 million at June 30, 2010. As this adjustment is unrealized, the offset is included in AOCL.

In accordance with IAS 39, hedge effectiveness testing must incorporate the Partnerships' credit risk which resulted in the Partnership's deficit increasing by $1.6 million at June 30, 2010. As this adjustment is unrealized, the offset is to the AOCL, which are recorded net of tax.

The tax impacts recorded against the above adjustments was $nil at June 30, 2010.

Other impacts also include the impact to the deferred tax assets and deferred tax liabilities resulting from all of the IFRS transition adjustments discussed above. The deferred tax asset decreased by $3.6 million at June 30, 2010. The deferred tax liability decreased by $4.3 million at June 30, 2010.

AOCL increased by $1.2 million at June 30, 2010 as a result of translating the other adjustments for the Partnership's operations with a US dollar functional currency.

Capital Power Income L.P.

Notes to the Condensed Interim Consolidated Financial Statements (Continued)

June 30, 2011

(Unaudited, tabular amounts in millions of Canadian dollars)

7. Transition to IFRS (Continued)

Reconciliation of total comprehensive income (loss)

Reconciliation of total comprehensive income three months ended June 30, 2010

	Canadian GAAP	IAS 16 and 37	IAS 36 (a)	IFRS 1	Other impacts (b)	Presentation adjustment	IFRS
Revenues	$ 97.3	$	$	$	$	$	$ 97.3
Cost of fuel	46.6				0.4		47.0
Operating and maintenance expense	24.2						24.2
	26.5				(0.4)		26.1
Other costs (income)							
Depreciation	26.3	(0.9)	(0.3)	0.9		(1.5)	24.5
Administrative and other expenses	1.6						1.6
Finance costs	8.0	(1.3)				3.3	10.0
Finance income						(1.8)	(1.8)
Income (loss) before income tax	(9.4)	2.2	0.3	(0.9)	(0.4)		(8.2)
Income tax recovery	(4.0)				(3.3)		(7.3)
Income (loss) for the period	(5.4)	2.2	0.3	(0.9)	2.9		(0.9)
Other comprehensive income (loss)	32.9	(1.2)	(1.1)	4.2	(3.4)		31.4
Total comprehensive income (loss)	$ 27.5	$ 1.0	$ (0.8)	$ 3.3	$ (0.5)	$	$ 30.5
Attributable to:							
Equity holders of the Partnership	$ 23.9	$ 1.0	$ (0.8)	$ 3.3	$ (0.5)	$	$ 26.9
Preferred share dividends of a subsidiary company	3.6						3.6

Capital Power Income L.P.

Notes to the Condensed Interim Consolidated Financial Statements (Continued)

June 30, 2011

(Unaudited, tabular amounts in millions of Canadian dollars)

7. Transition to IFRS (Continued)

Reconciliation of total comprehensive income six months ended June 30, 2010

	Canadian GAAP	IAS 16 and 37	IAS 36 (a)	IFRS 1	Other impacts (b)	Presentation adjustment	IFRS
Revenues	$ 241.5	$	$	$	$	$	$ 241.5
Cost of fuel	117.3				(0.4)		116.9
Operating and maintenance expense	46.8						46.8
	77.4				0.4		77.8
Other costs (income)							
Depreciation	49.8	(1.2)	(0.5)	1.7		(1.9)	47.9
Administrative and other expenses	5.6						5.6
Finance costs	19.0	(1.3)				3.7	21.4
Finance income						(1.8)	(1.8)
Income (loss) before income tax	3.0	2.5	0.5	(1.7)	0.4		4.7
Income tax recovery	(9.5)				(1.4)		(10.9)
Income for the period	12.5	2.5	0.5	(1.7)	1.8		15.6
Other comprehensive income (loss)	(16.1)	(0.2)	(0.3)	1.1	0.4		(15.1)
Total comprehensive (income) loss	$ (3.6)	$ 2.3	$ 0.2	$ (0.6)	$ 2.2	$	$ 0.5
Attributable to:							
Equity holders of the Partnership	$ (10.8)	$ 2.3	$ 0.2	$ (0.6)	$ 2.2	$	$ (6.7)
Preferred share dividends of a subsidiary company	7.2						7.2

Notes to the total comprehensive income reconciliations

a) IAS 36 Impairment

The impact to depreciation as a result of implementing IAS 36 is a decrease of $0.3 million and $0.5 million for the three and six months ended June 30, 2010, respectively.

OCL increased by $1.1 million and $0.3 million for the three and six months ended June 30, 2010, respectively as a result of translating the IAS 36 adjustments for the Partnership's operations with a US dollar functional currency.

b) Other impacts

The impact of incorporating the Partnership's credit risk in the hedge effectiveness testing, under IAS 39, is an increase to the cost of fuel of $0.4 million and a decrease to fuel of $0.4 million for the three and six months ended June 30, 2010, respectively. The offset is an increase to OCL.

Capital Power Income L.P.

Notes to the Condensed Interim Consolidated Financial Statements (Continued)

June 30, 2011

(Unaudited, tabular amounts in millions of Canadian dollars)

7. Transition to IFRS (Continued)

The combined impact of these adjustments to income tax recovery for the three and six months ended June 30, 2010 is an increase of $3.3 million and $1.4 million, respectively.

The remaining adjustments impact OCL:

As a result of the Partnership using PERC's share price as a proxy, to determine the fair market value of its investment in PERH, OCL decreased by $0.5 million and $2.0 million for the three and six months ended June 30, 2010, respectively.

OCL increased by $4.3 million and $1.2 million for the three and six months ended June 30, 2010, respectively as a result of translating the other adjustments for the Partnership's operations with a US dollar functional currency.

Summary of other comprehensive loss adjustments

	Three months ended June 30, 2010	Six months ended June 30, 2010
IAS 39 Hedge effectiveness	0.4	(0.4)
IAS 39 PERH fair value	0.5	2.0
Foreign exchange impacts	(4.3)	(1.2)
	(3.4)	0.4

Shares

Common Shares

PROSPECTUS

Joint Book-Running Managers

TD Securities	**Morgan Stanley**

, 2011

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PART II

INFORMATION NOT REQUIRED IN PROSPECTUS

Item 13. Other Expenses of Issuance and Distribution.

The following table sets forth the estimated costs and expenses payable by the registrant in connection with the registration of securities being registered under this registration statement. All amounts except the SEC registration fee and FINRA filing fee are estimates.

SEC registration fee	$	26,703
FINRA filing fee		23,500
Legal fees and expenses		*
Accounting fees and expenses		*
Printing and related expenses		*
Transfer agent fees and expenses		*
Miscellaneous expenses		*
Total	$	*

* To be furnished by amendment

Item 14. Indemnification of Directors and Officers.

Under the *Business Corporations Act* (British Columbia), which we refer to as the "BC Act," we may indemnify a present or former director or officer or a person who acts or acted at our request as a director or officer of another corporation or one of our affiliates, and his or her heirs and personal representatives, against all costs, charges and expenses, including legal and other fees and amounts paid to settle an action or satisfy a judgment, actually and reasonably incurred by him or her including an amount paid to settle an action or satisfy a judgment in respect of any legal proceeding or investigative action to which he or she is made a party by reason of his or her position and provided that the director or officer acted honestly and in good faith with a view to the best interests of Atlantic Power Corporation or such other corporation, and, in the case of a criminal or administrative action or proceeding, had reasonable grounds for believing that his or her conduct was lawful. Other forms of indemnification may be made with court approval.

In accordance with our Articles, we shall indemnify every director or former director, or may, subject to the BC Act, indemnify any other person. We have entered into indemnity agreements with our directors and executive officers, whereby we have agreed to indemnify the directors and officers to the extent permitted by our Articles and the BC Act.

Our Articles permit us, subject to the limitations contained in the BC Act, to purchase and maintain insurance on behalf of any person, as the board of directors may from time to time determine. Our directors and officers liability insurance coverage consists of three policies with aggregate limits of $30 million.

The foregoing summaries are necessarily subject to the complete text of the statute and our Articles, and the arrangements referred to above are qualified in their entirety by reference thereto.

Item 15. Recent Sales of Unregistered Securities.

Since July 1, 2008, we have issued 352,320 IPSs and/or common shares to three employees pursuant to our long term incentive program ("LTIP"). These issuances were exempt from registration either pursuant to Rule 701 under the Securities Act, as a transaction pursuant to a compensatory benefit plan, or pursuant to Section 4(2) of the Securities Act, as a transaction by an issuer not involving a public offering.

On November 27, 2009, we completed the conversion of all of our IPSs to common shares. The exchange of IPSs for common shares was exempt from registration pursuant to Section 3(a)(10) of the Securities Act, which exempts offers and sales of securities in exchange transactions where a reviewing court or authorized governmental entity approves the fairness of the exchange following an open hearing. The IPSs were exchanged for common shares and the Supreme Court of British Columbia approved the terms and conditions of the exchange after a hearing upon the fairness of such terms and conditions at which all holders of IPSs had the right to appear.

In December 2009, we completed a public offering in Canada of an aggregate of C$86.25 million of our 6.25% convertible unsecured subordinated debentures due 2017 in a transaction exempt from registration pursuant to Regulation S under the Securities Act. The terms of the debentures provide that they can be converted into our common shares at the option of the holder at a conversion price of C$13.00 per common share, or approximately 76.9231 common shares per C$1,000 principal amount of debentures, subject to adjustment in accordance with the trust indenture governing the terms of the debentures. The principal underwriter was BMO Nesbitt Burns Inc. and aggregate underwriting commissions were C$3.45 million. We used the net proceeds of the offering principally to redeem all or substantially all of our outstanding 11.0% subordinated notes, and the remainder for general corporate purposes, including acquisitions.

Item 16. Exhibits and Financial Statement Schedules.

A list of exhibits filed with this registration statement on Form S-1 is set forth on the Exhibit Index and is incorporated herein by reference.

Item 17. Undertakings.

(a) Insofar as indemnification for liabilities arising under the Securities Act of 1933, as amended, may be permitted to directors, officers and controlling persons of the registrant pursuant to the foregoing provisions, or otherwise, the registrant has been advised that in the opinion of the Securities and Exchange Commission such indemnification is against public policy as expressed in the Act and is, therefore, unenforceable. In the event that a claim for indemnification against such liabilities (other than the payment by the registrant of expenses incurred or paid by a director, officer or controlling person of the registrant in the successful defense of any action, suit or proceeding) is asserted by such director, officer or controlling person in connection with the securities being registered, the registrant will, unless in the opinion of its counsel the matter has been settled by controlling precedent, submit to a court of appropriate jurisdiction the question whether such indemnification by it is against public policy as expressed in the Act and will be governed by the final adjudication of such issue.

(b) The undersigned registrant hereby undertakes that:

(i) For purposes of determining any liability under the Securities Act of 1933, as amended, the information omitted from the form of prospectus filed as part of this registration statement in reliance upon Rule 430A and contained in a form of prospectus filed by the registrant pursuant to Rule 424(b)(1) or (4) or 497(h) under the Securities Act shall be deemed to be part of this registration statement as of the time it was declared effective.

(ii) For the purpose of determining any liability under the Securities Act of 1933, as amended, each post-effective amendment that contains a form of prospectus shall be deemed to be a new registration statement relating to the securities offered herein, and the offering of such securities at that time shall be deemed to be the initial bona fide offering thereof.

(c) That, for the purpose of determining liability of the registrant under the Securities Act of 1933 to any purchaser in the initial distribution of the securities: The undersigned registrant undertakes that in a primary offering of securities of the undersigned registrant pursuant to this registration statement, regardless of the underwriting method used to sell the securities to the purchaser, if the securities are offered or sold to such purchaser by means of any of the following communications, the undersigned registrant will be a seller to the purchaser and will be considered to offer or sell such securities to such purchaser:

(i) Any preliminary prospectus or prospectus of the undersigned registrant relating to the offering required to be filed pursuant to Rule 424;

(ii) Any free writing prospectus relating to the offering prepared by or on behalf of the undersigned registrant or used or referred to by the undersigned registrant;

(iii) The portion of any other free writing prospectus relating to the offering containing material information about the undersigned registrant or its securities provided by or on behalf of the undersigned registrant; and

(iv) Any other communication that is an offer in the offering made by the undersigned registrant to the purchaser.

(d) That, for the purpose of determining liability under the Securities Act of 1933 to any purchaser, if the registrant is subject to Rule 430C, each prospectus filed pursuant to Rule 424(b) as part of a registration statement relating to an offering, other than registration statements relying on Rule 430B or other than prospectuses filed in reliance on Rule 430A, shall be deemed to be part of and included in the registration statement as of the date it is first used after effectiveness. Provided, however, that no statement made in a registration statement or prospectus that is part of the registration statement or made in a document incorporated or deemed incorporated by reference into the registration statement or prospectus that is part of the registration statement will, as to a purchaser with a time of contract of sale prior to such first use, supersede or modify any statement that was made in the registration statement or prospectus that was part of the registration statement or made in any such document immediately prior to such date of first use.

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SIGNATURES

Pursuant to the requirements of the Securities Act of 1933, as amended, the registrant certifies that it has reasonable grounds to believe that it meets all of the requirements for filing on Form S-1 and that it has duly caused this Amendment No. 1 to Registration Statement to be signed on its behalf by the undersigned, thereunto duly authorized, in the City of Boston, The Commonwealth of Massachusetts, on the 15th day of September, 2011.

ATLANTIC POWER CORPORATION

By: /s/ BARRY E. WELCH

Barry E. Welch
President, Chief Executive Officer
(Principal Executive Officer)

Pursuant to the requirements of the Securities Act of 1933, as amended, this Amendment No. 1 to Registration Statement has been signed by the following persons in the capacities and on the dates indicated.

Signature	Title	Date
/s/ BARRY E. WELCH Barry E. Welch	President, Chief Executive Officer and Director (principal executive officer)	September 15, 2011
* Lisa Donahue	Interim Chief Financial Officer (principal financial and accounting officer)	September 15, 2011
* Irving R. Gerstein	Chairman of the Board	September 15, 2011
* Kenneth M. Hartwick	Director	September 15, 2011
* Richard Foster Duncan	Director	September 15, 2011
* John A. McNeil	Director	September 15, 2011

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Signature	Title	Date
* Holli Nichols	Director	September 15, 2011

*By: /s/ BARRY E. WELCH

Barry E. Welch
Attorney-in-fact

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INDEX TO EXHIBITS

Exhibit No.	Description
1.1	Form of Underwriting Agreement*
2.1	Plan of Arrangement of Atlantic Power Corporation, dated as of November 24, 2005(1)
2.2	Arrangement Agreement, dated as of June 20, 2011, among Capital Power Income L.P., CPI Income Services Ltd., CPI Investments Inc. and Atlantic Power Corporation(4)
3.1	Articles of Continuance of Atlantic Power Corporation, dated June 29, 2010(2)
3.2	Certificate of Incorporation of Atlantic Power Corporation, dated June 18, 2004(1)
3.3	Articles of Amendment of Atlantic Power Corporation, dated September 13, 2004(4)
4.1	Form of common share certificate(1)
4.2	Trust Indenture, dated as of October 11, 2006 between Atlantic Power Corporation and Computershare Trust Company of Canada(1)
4.3	First Supplemental Indenture to the Trust Indenture Providing for the Issue of Convertible Secured Debentures, dated November 27, 2009, between Atlantic Power Corporation and Computershare Trust Company of Canada(1)
4.4	Trust Indenture Providing for the Issue of Convertible Unsecured Subordinated Debentures, dated as of December 17, 2009, between Atlantic Power Corporation and Computershare Trust Company of Canada(1)
4.5	Form of First Supplemental Indenture to the Trust Indenture Providing for the Issue of Convertible Unsecured Subordinated Debentures, between Atlantic Power Corporation and Computershare Trust Company of Canada(3)
5.1	Form of Opinion of Goodmans
10.1	Credit Agreement dated as of November 18, 2004 among Atlantic Power Holdings, Inc. as borrower, Bank of Montreal as Administrative Agent, LC issuer and collateral agent and the Other Lenders party thereto, and Harris Nesbitt Corp. as arranger(1)
10.2	Employment Agreement, dated as of December 31, 2009 between Atlantic Power Corporation and Barry Welch(1)
10.3	Employment Agreement, dated as of December 31, 2009 between Atlantic Power Corporation and Patrick Welch(1)
10.4	Employment Agreement, dated as of December 31, 2009 between Atlantic Power Corporation and Paul Rapisarda(1)
10.5	Deferred Share Unit Plan, dated as of April 24, 2007 of Atlantic Power Corporation(1)
10.6	Third Amended and Restated Long-Term Incentive Plan, adopted June 29, 2010(2)
10.7	Second Amended and Restated Long-Term Incentive Plan, adopted June 4, 2008(1)
21.1	Subsidiaries of Atlantic Power Corporation(5)
23.1	Consent of Goodmans (included in Exhibit 5.1)
23.2	Consent of KPMG LLP
23.3	Consent of KPMG LLP

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Exhibit No.	Description
23.4	Consent of PricewaterhouseCoopers LLP
23.5	Consent of KPMG LLP
24.1	Powers of Attorney, included on signature page of the registrant's S-1(5)

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* To be filed by amendment.

(1) Incorporated by reference to our registration statement on Form 10-12B filed with the Commission on April 13, 2010.

(2) Incorporated by reference to our registration statement on Form 10-12B/A filed with the Commission on July 9, 2010.

(3) Incorporated by reference to our registration statement on Form S-1/A (File No. 333-168855) filed with the Commission on September 17, 2010.

(4) Incorporated by reference to our Current Report on Form 8-K filed with the Commission on June 24, 2011.

(5) Incorporated by reference to our registration statement on Form S-1 (File No. 333-176257) filed with the Commission on August 12, 2011.