Atlantic Power 2010 Annual Report

# Invest in Power

AtlanticPower Corporation

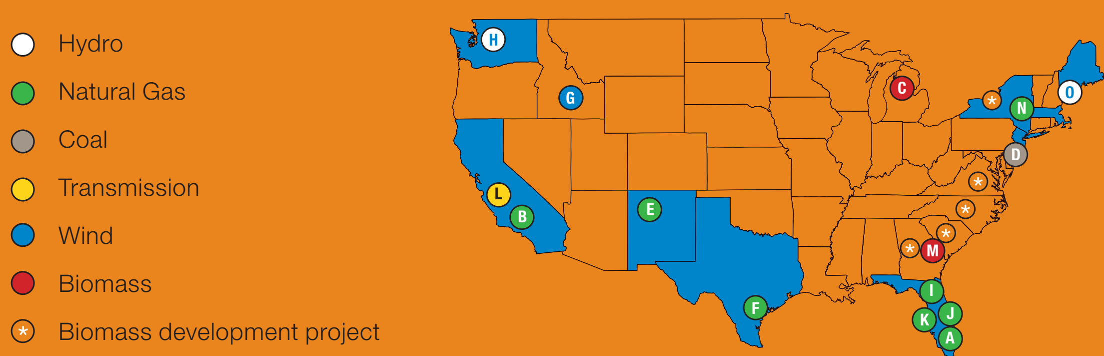
# Corporate Profile

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 1,962 megawatts (MW), in which our ownership interest is approximately 878 MW. Our corporate strategy is to generate stable cash flows from our existing assets and to make accretive acquisitions to sustain our dividend payout to shareholders, which is currently paid monthly at an annual rate of Cdn$1.094 per share. Our current portfolio consists of interests in 13 operational power generation projects across 10 states, one biomass project under construction in Georgia, and an 84-mile, 500-kilovolt electric transmission line located in California. Atlantic Power also owns a majority interest in Rollcast Energy, a biomass power plant developer with several projects under development.

Atlantic Power trades on the New York Stock Exchange under the symbol AT, on the Toronto Stock Exchange under the symbol ATP and has a market capitalization of approximately $1.0 billion.

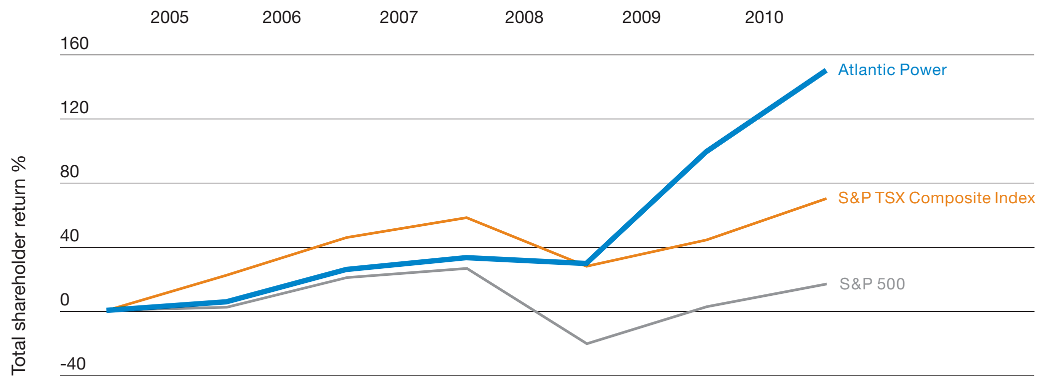
# Projects at a Glance

Our diversified and well positioned power producing and related assets, located in major U.S. electricity markets, continue to deliver strong operating performance and stable, sustainable and growing cash flow for investors.




| | PROJECT NAME | LOCATION | FUEL TYPE | TOTAL MW | OWNERSHIP INTEREST | NET MW |
|---|---|---|---|---|---|---|
| A | Auburndale | Auburndale FL | Natural Gas | 155 | 100% | 155 |
| B | Badger Creek | Bakersfield CA | Natural Gas | 46 | 50% | 23 |
| C | Cadillac | Cadillac MI | Biomass | 40 | 100% | 40 |
| D | Chambers | Carney's Point NJ | Coal | 262 | 40% | 105 |
| E | Delta-Person | Albuquerque NM | Natural Gas | 132 | 40% | 53 |
| F | Gregory | Corpus Christi TX | Natural Gas | 400 | 17% | 68 |
| G | Idaho Wind | Twin Falls ID | Wind | 183 | 28% | 50 |
| H | Koma Kulshan | Concrete WA | Hydro | 13 | 50% | 6 |
| I | Lake | Umatilla FL | Natural Gas | 121 | 100% | 121 |
| J | Orlando | Orlando FL | Natural Gas | 129 | 50% | 65 |
| K | Pasco | Tampa FL | Natural Gas | 121 | 100% | 121 |
| L | Path 15 | California | Transmission | N/A | 100% | N/A |
| M | Piedmont* | Barnsville GA | Biomass | 54 | 98% | 53 |
| N | Selkirk | Bethlehem NY | Natural Gas | 345 | 18% | 64 |
| O | Topsham** | Topsham ME | Hydro | 14 | 50% | 7 |

*Under construction **Sold in the second quarter of 2011




Total Shareholder Return 2005 – 2010

# The Year in Review

## 1

### NYSE LISTING AND CROSS-BORDER CAPITAL RAISE

- Dual-listed in July on NYSE
- Doubled the liquidity of our shares
- Increased access to competitively priced capital
- Broadened shareholder base
- Raised $160 million in a cross-border equity offering and a convertible debenture offering in Canada
- Proceeds were deployed to fund equity interests in two biomass plants and a wind power project

## 2

### RENEWABLE DEVELOPMENT AND ACQUISITION THROUGH PROPRIETARY TRANSACTIONS

- Added 142 MW of renewable generation to our portfolio
- Invested $40 million in Idaho Wind Partners, a late-stage wind development project that was delivered on time and on budget
- Invested $75 million in Piedmont Green Power, the first biomass development project to come through Rollcast Energy's project pipeline
- Invested $37 million in Cadillac Renewable Energy, an operational biomass facility in Cadillac, Michigan

## 3

### INVESTMENT IN ROLLCAST ENERGY AND BIOMASS DEVELOPMENT OPPORTUNITIES

- Increased our ownership in Rollcast Energy, a biomass project developer in the U.S. Southeast, to 60%
- Continued involvement in development with the opportunity to invest in late-stage biomass projects
- Additional biomass facilities under development in the U.S. Southeast
- Leveraged our affiliation with Rollcast for due diligence on the acquisition of Cadillac Renewable Energy

## 4

### FINANCIAL PERFORMANCE AND KEY GROWTH METRICS

- Exceeded 2010 project distribution guidance
- Total shareholder return of 39%
- Increased our enterprise value by approximately 54%
- Increased Project Adjusted EBITDA from acquisitions by approximately 8.5% to $84.8 million
- Extended the average PPA life of our portfolio by 30%
- Increased our generating portfolio MWs by 18%

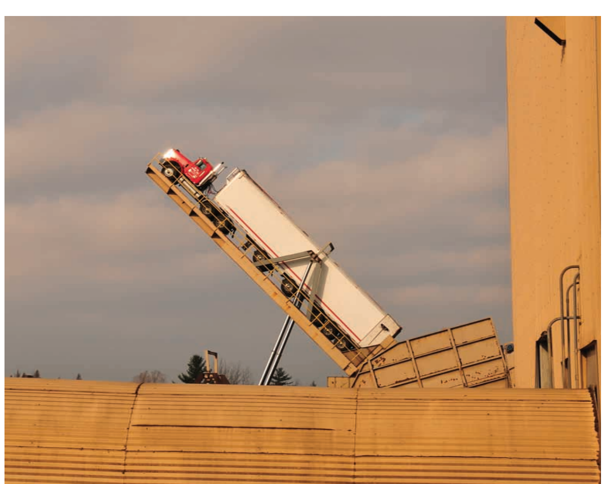
# Report to Shareholders

Over the past few years at Atlantic Power, we have firmly established our reputation as a reliable partner and a leader in the development, financing and operation of electric generation and transmission assets. In 2010, we capitalized on that reputation and deployed $150 million of equity in three diverse clean power opportunities, expanding our portfolio not only through an acquisition, but also through the successful development and construction of two renewable energy projects. Our listing on the New York Stock Exchange brought numerous benefits to our shareholders and allowed us to execute a successful cross-border capital raise in the second half of 2010. When I look back at all we have achieved in the past year, I have a tremendous sense of pride in what has been accomplished by our team here at Atlantic Power.

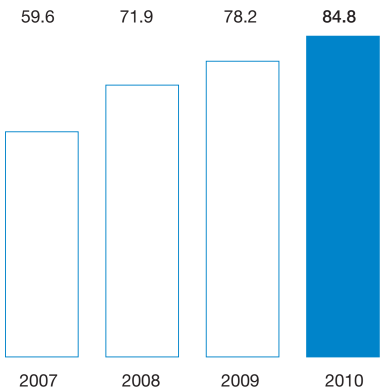
The listing of our shares on the New York Stock Exchange last July significantly enhanced our access to competitively priced capital and more than doubled our trading liquidity. The extension of our reach into the United States capital market sets us apart from our Canadian peers as we can optimize our capital structure by issuing public securities in the U.S. Moreover, we have now begun to proactively market to and attract institutional investors in the United States, many of whom are currently looking for companies with solid business models and stable dividends.

In October, we leveraged our new dual-listed status to raise approximately $150 million in capital through cross-border offerings of common shares and a convertible debenture offering in Canada. The capital raised was deployed to fund our equity interests in three renewable energy projects: $75 million in Piedmont Green Power, our first biomass development project, which is currently under construction with completion expected in late 2012; $40 million in Idaho Wind Partners, our first wind power project, which completed construction and started commercial operation in early 2011; and $37 million in Cadillac Renewable Energy, a biomass facility in Cadillac, Michigan, which has been operating since 1993. The first two transactions were proprietary sourced opportunities and the third was a narrow auction process where our relationship with the sellers gave us a clear advantage.

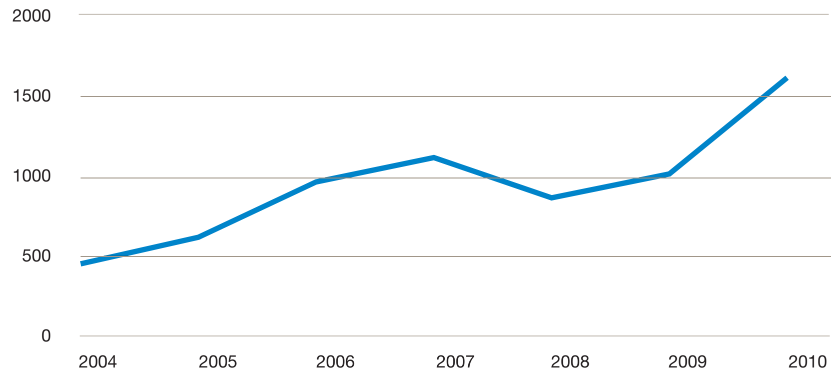
In October, Rollcast Energy, our biomass project development affiliate, reached a significant milestone by closing its non-recourse project-level financing for Piedmont Green Power, the first biomass project coming through its development pipeline. Financing was achieved in no small part due to our reputation and track record with the lead lender, as well as the strength of the underlying contracts of the project, including a 20-year PPA with Georgia Power. With late-stage development successfully accomplished, we have turned our attention to managing Piedmont's construction, from ground-breaking to full



Renewables: In 2010, we expanded our renewable portfolio by 142 MW through investments in two biomass projects and a wind farm. Renewable power development will play an important role throughout the United States and Canada as pressure increases on utilities to source green power. A part of our growth strategy focuses on late-stage renewable development in wind, biomass and solar. These projects not only have favorable economics due to federal grant programs in the U.S. and incentive programs in Canada, but also strong contracts with utilities due to expanding U.S. state Renewable Portfolio Standards.




## Continued Growth in Adjusted EBITDA from Acquisitions ($ millions)




## Tripled Enterprise Value Since 2004

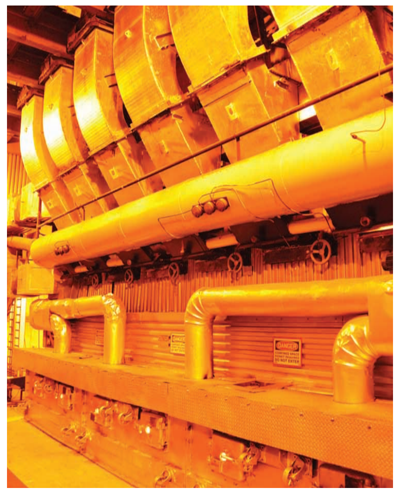
($ millions)

commercial operation. Shortly after construction is complete, the project will benefit from a federal grant providing approximately 30% of its capital cost. We expect to receive $8 to $10 million in project distributions from Piedmont for each full year of commercial operation, starting in 2013.

Our history of growth through proprietary transactions was further strengthened this year with the equity interest we acquired in Idaho Wind Partners, our first wind power project. We were approached during late-stage development to invest equity in Idaho Wind and we were able to negotiate a transaction to acquire a 27.6% interest in the project through our well-established relationships with GE and Reunion Power. Construction began in the summer of 2010, and the project was delivered on budget and on schedule in early 2011, despite the challenge posed by winter weather. Idaho Wind Partners sells its electricity to Idaho Power Company under 20-year PPAs, and provides cash flows that are accretive for our shareholders. We are confident that we will be able to use the partnership experience we gained on Idaho Wind to successfully negotiate other project opportunities in late-stage wind development.

In December, we acquired Cadillac Renewable Energy, a 39.6 MW biomass facility in Cadillac, Michigan. Cadillac has operated with an impressive availability, safety and environmental record for over 15 years under a PPA with Consumers Energy that expires in 2028. The project uses readily sourced wood waste from multiple suppliers and,

**Wind:** Our first investment in a wind development project, Idaho Wind Partners, began construction in the summer of 2010 and was completed on time and on budget in early 2011. Late-stage wind development projects with short construction timelines will continue to provide opportunities to add accretive cash flows to our portfolio.



like Piedmont, has a neutral carbon footprint. The expertise of our Rollcast affiliate was instrumental in the aquisition process and they are managing the project's operations, maintenance and fuel supply. Cadillac is immediately accretive to cash available for distribution to shareholders, and Rollcast has already achieved efficiencies and fuel cost reductions at the project.

The addition of these three renewable projects extended our average PPA life by 30%, from 6.8 years to 8.9 years, and will increase our generating portfolio by approximately 18% from 788 MW to 930 MW by adding 142 MW of renewable power generation. The continued execution of our acquisition strategy meets the underlying goals of our shareholders by continuing to extend the long-term contracted cash flows, which support the sustainability of our dividend and underpin the capital appreciation of our shares. Our reputation and relationships provide a steady stream of proprietary opportunities for Atlantic Power to invest capital in projects that meet our risk and return guidelines and also add diversification benefits.

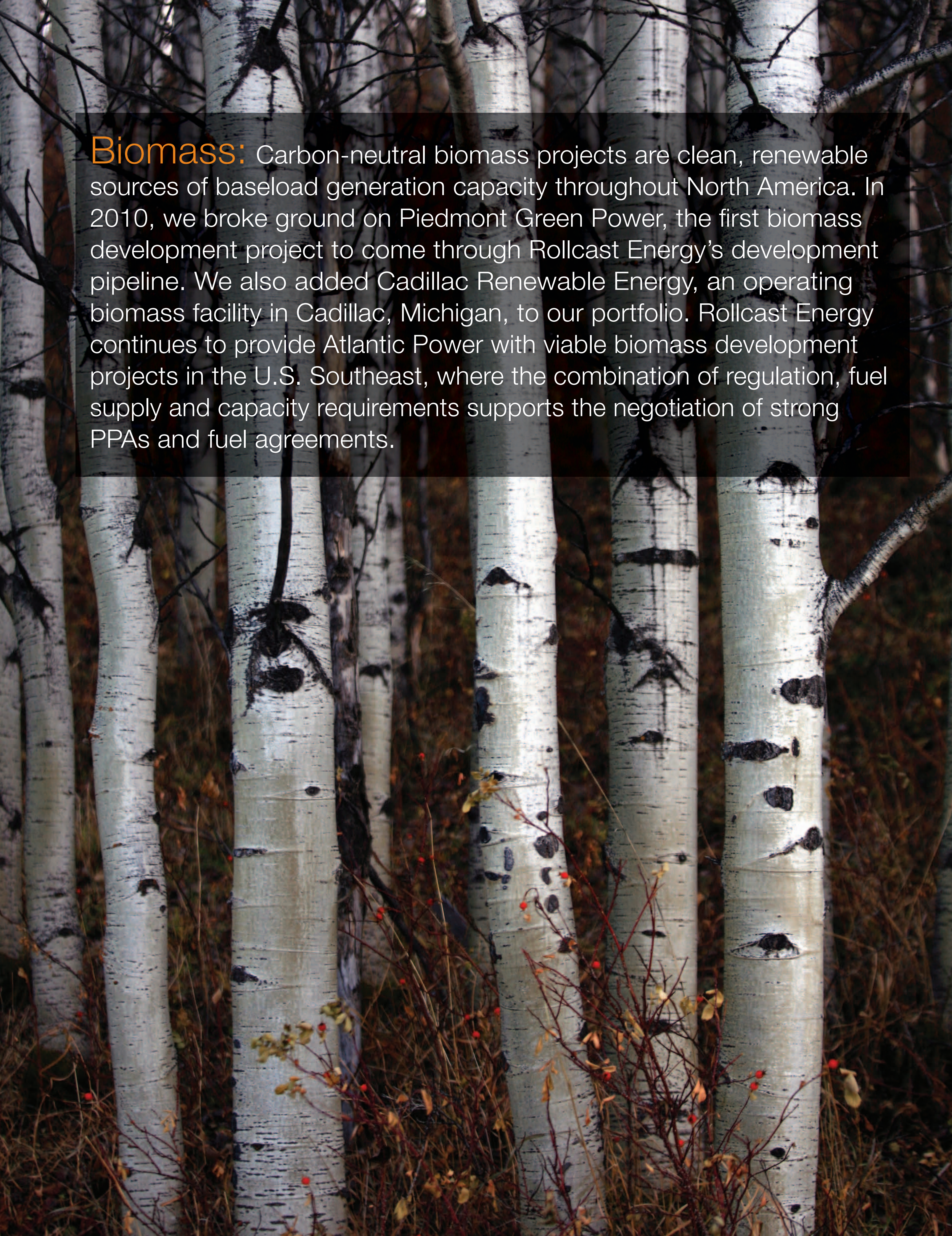
Our project operations remained steady through the recession-related drop in electricity demand, with 2010 project distributions exceeding our guidance. Our natural gas-fired plants in Florida were called on to generate similar levels of electricity, year over year, despite lower electricity demand in the Florida market in 2009 and 2010. The majority of our efficient gas-fired assets are strategically positioned as "mid-merit" plants that typically operate five days a week for 10 to 14 hours a day, and are called upon consistently to meet electricity demand in the markets they serve. The weighted average availability of our projects remained at over 95% while maintaining an outstanding safety record.

We continue to enhance the predictability of our operating margins by mitigating exposure to commodity price fluctuations and through ongoing negotiations with electricity off-takers. These efforts result in stable project operating margins to support our dividend, and provide us with the confidence that we could meet our current dividend obligations into 2016 even if we had no further acquisitions or organic growth.

As I look back at all that we have accomplished since our IPO in late 2004, I can't help but take a moment to share some remarkable statistics. Since that time, we have more than tripled our enterprise value and raised our dividend three times, with the most recent increase coming at a time of tightened credit markets in late 2008. From our IPO to December 31, 2010, Atlantic Power provided a total shareholder return of 159%, exceeding the TSX Income Trust Composite, S&P TSX Composite, and the S&P 500 indices by 64%, 84%, and 140%, respectively. Additionally, we completed eight acquisitions, adding accretive cash flows and steadily increasing our total project adjusted EBITDA from acquisitions alone to approximately $85 million in 2010.

Looking ahead at 2011 and beyond, we are well positioned to access competitively priced capital to fuel the accretive growth of our asset base, enhance the long-term stability of cash flows through risk mitigation strategies and manage our current portfolio of assets to increase efficiencies.

Biomass: Carbon-neutral biomass projects are clean, renewable sources of baseload generation capacity throughout North America. In 2010, we broke ground on Piedmont Green Power, the first biomass development project to come through Rollcast Energy's development pipeline. We also added Cadillac Renewable Energy, an operating biomass facility in Cadillac, Michigan, to our portfolio. Rollcast Energy continues to provide Atlantic Power with viable biomass development projects in the U.S. Southeast, where the combination of regulation, fuel supply and capacity requirements supports the negotiation of strong PPAs and fuel agreements.



# Report to Shareholders, continued

Given the current market trends in the industry, including Renewable Portfolio Standards in 31 U.S. states and U.S. federal stimulus grants, as well as renewables incentives in Canada, we believe that late-stage renewable project development will continue to provide opportunities for Atlantic Power to deploy capital and expand our clean power portfolio. In order to meet new Renewable Portfolio Standards, we are seeing utilities provide valuable long-term PPAs of up to 20 years to facilitate the financing and construction of renewable development projects.

When we look at specific opportunities to invest in late-state development, Rollcast Energy continues to provide executable biomass development projects in the U.S. Southeast. Just as Rollcast was able to bring Piedmont Green Power over the development finish line, we see other projects coming on line with strong PPAs and fuel supply agreements. We are also looking for similar equity investment opportunities in wind and solar development companies that can deliver late-stage development projects where we can put capital to work and achieve accretive returns on a relatively short timeline. We continue to be interested in opportunities to expand our clean power portfolio through the acquisition of natural gas-fired plants. Moreover, we are able to consider corporate acquisition opportunities that provide diversification and synergies with regard to their operations, fall within our risk-return corridor for projects and may also include a development pipeline.

We are pleased that our shareholders have continued to support the vision we have for the sustainable growth of Atlantic Power, and we take very seriously the trust that is placed in us to work hard toward meeting our shareholders' objectives for many years to come. We would also like to thank all of our employees and partners for making 2010 a successful year at Atlantic Power.

Barry Welch
President and Chief Executive Officer

**Management Team**
From left to right:

**Paul Rapisarda**
Managing Director,
Asset Management
and Acquisitions

**Barry Welch**
President and Chief
Executive Officer

**Patrick Welch**
Chief Financial Officer
and Corporate Secretary

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

# FORM 10-K

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

**For the fiscal year ended December 31, 2010**

**OR**

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

**For the transition period from to**

**Commission file number 001-34691**

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

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

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

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

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

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

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

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

Indicate by check mark whether the registrant: (1) has filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the registrant was required to file such reports), and (2) has been subject to such filing requirements for the past 90 days. Yes ☒ No ☐

Indicate by check mark whether the registrant has submitted electronically and posted on its corporate Website, if any, every Interactive Data File required to be submitted and posted pursuant to Rule 405 of Regulation S-T (§232.405 of this chapter) during the preceding 12 months (or for such shorter period that the registrant was required to submit and post such files). ☐ Yes ☐ No

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

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

| | | | |
|---|---|---|---|
| Large Accelerated Filer ☐ | Accelerated Filer ☐ | Non-Accelerated Filer ☒<br>(Do not check if a smaller reporting company) | Smaller reporting company ☐ |

Indicate by check mark whether the registrant is a shell company (as defined in Rule 12b-2 of the Exchange Act). Yes ☐ No ☒

As of March 15, 2011, the aggregate market value of the 67,853,964 Common Shares, no par value per share, held by non-affiliates of the registrant was $1,035.5 million based upon the last reported sale price of $15.26 on the New York Stock Exchange. For purposes of the foregoing calculation only, all directors and executive officers of the registrant have been deemed affiliates.

As of March 18, 2011, 68,108,042 of the registrant's Common Shares were outstanding.

**DOCUMENTS INCORPORATED BY REFERENCE**

Portions of the registrant's definitive Proxy Statement for its 2011 Annual Meeting of Shareholders, to be filed not later than 120 days after the end of the registrant's fiscal year, are incorporated by reference into Items 10 through 14 of Part III of this Annual Report on Form 10-K.

**TABLE OF CONTENTS**



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

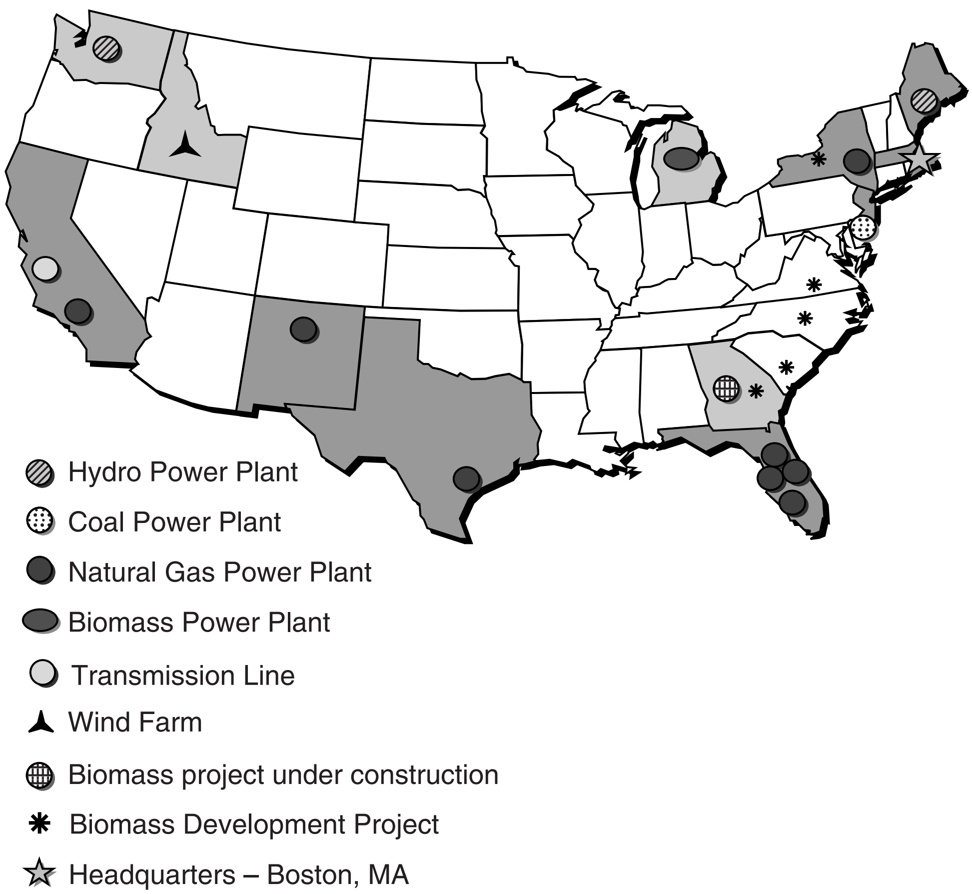
## PART I

## ITEM 1. BUSINESS

### OVERVIEW

Atlantic Power Corporation owns interest in 13 operational power generation projects across ten states, one biomass project under construction in Georgia, a 500 kilovolt 84-mile electric transmission line located in California and several development projects. Our power generation projects in operation have an aggregate gross electric generation capacity of approximately 1,962 megawatts ("MW"), in which our ownership interest is approximately 878 MW.

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




We sell the capacity and energy from our projects under power purchase agreements ("PPAs") with a variety of utilities and other parties. Under the PPAs, which have expiration dates ranging from 2011 to 2037, we receive payments for electric energy sold to our customers (known as energy payments), in addition to payments for electric generation capacity (known as capacity payments). We also sell steam from a number of our projects under steam sales agreements to industrial purchasers. The transmission system rights we own in our power transmission project entitle us to payments indirectly from the utilities that make use of the transmission line.

Our projects generally operate pursuant to long-term fuel supply agreements, typically accompanied by fuel transportation arrangements. In most cases, the terms of the fuel supply and transportation arrangements correspond to the terms of the relevant PPAs. Many of the PPAs and steam sales agreements provide for the pass-through or indexing of fuel costs to our customers.

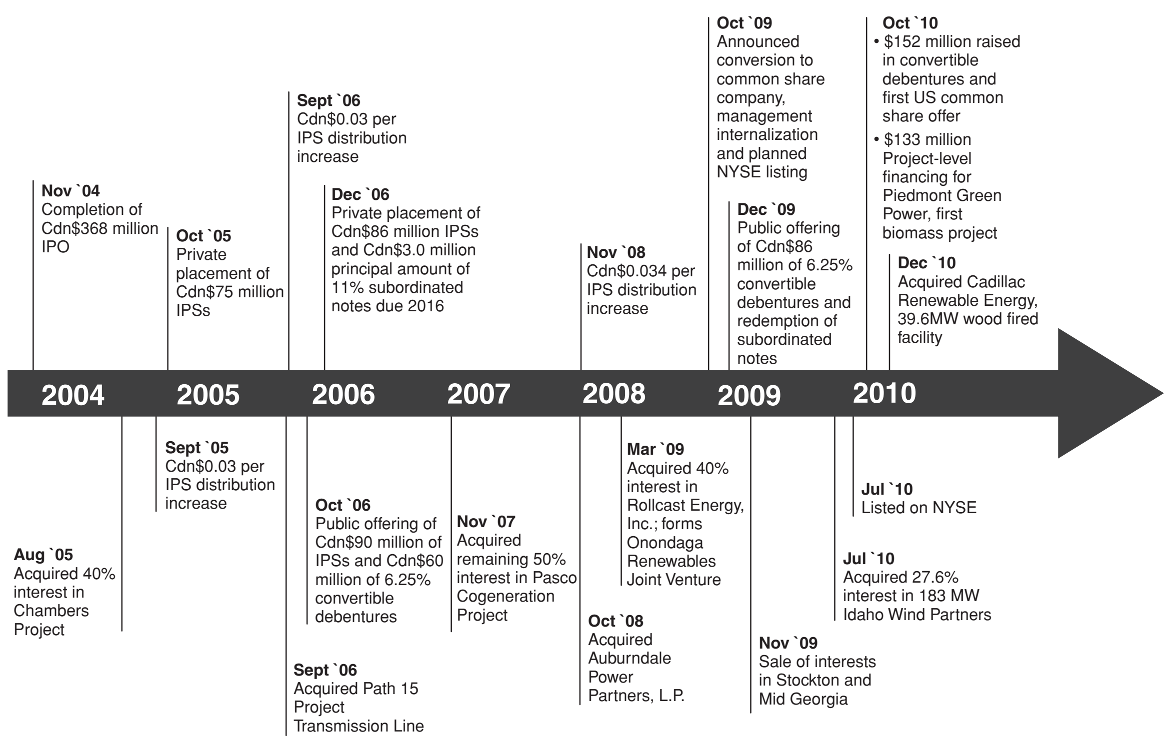
We partner with recognized leaders in the power business to operate and maintain our projects, including Caithness Energy ("Caithness"), Power Plant Management Services ("PPMS"), Delta Power Services and the Western Area Power Administration ("Western"). Our asset management team works with these operators to proactively pursue opportunities to both improve the performance of our physical assets and optimize the various project contracts for enhanced financial performance.

Atlantic Power Corporation is organized under the laws of the Province of British Columbia. Our registered office is located at 355 Burrard Street, Suite 1900, Vancouver, British Columbia, Canada V6C 2G8 and our headquarters are located at 200 Clarendon Street, Floor 25, Boston, Massachusetts, USA 02116. Our website is www.atlanticpower.com. Information contained on our website is not part of this Form 10-K.

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 Cdn$5.767 principal value of 11% subordinated notes due 2016. On November 17, 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".

## HISTORY OF OUR COMPANY

Atlantic Power Corporation is a Canadian corporation that was formed in 2004. The following timeline illustrates significant events in the development of our business since our initial public offering. Further details about these events are included below:



We used the proceeds from our IPO to acquire a 58% interest in Atlantic Power Holdings, LLC (now Atlantic Power Holdings, Inc., which we refer to herein as "Atlantic Holdings") from two private equity funds managed by ArcLight Capital Partners, LLC and from Caithness. Until December 31, 2009, we were externally managed by Atlantic Power Management, LLC, an affiliate of ArcLight. Under this external management arrangement, ArcLight provided administrative and office support services to us and was required to give us the opportunity to pursue investment opportunities that did not fit ArcLight's investment guidelines for its private equity funds. At the time of our IPO, Atlantic Holdings was granted a right of first offer related to ArcLight's interest in 11 power generating projects. Our acquisitions of a 40% interest in the Chambers project in 2005 and the Auburndale project in 2008 were completed under the terms of this right of first offer, which has since expired.

In August 2005, we acquired Epsilon Power Partners, LLC, which owns a 40% interest in the Chambers project, for approximately $63 million in cash and the assumption of $43 million in non-recourse debt.

In October 2005, we completed a private placement of 7,500,000 IPSs. We used the net proceeds of the private placement to increase our ownership in Atlantic Holdings to 70.1%.

In September 2006, we acquired 100% of the equity interests in Trans-Elect NTD Holdings Path 15, LLC (Path 15), which has since been renamed Atlantic Path 15 Holdings, LLC and indirectly owns approximately 72% of the transmission system rights in the transmission line upgrade along the Path 15 transmission corridor located in central California. The purchase price was approximately $78.4 million.

In October 2006, we completed a sale of 8,531,000 IPSs and debentures for gross proceeds of Cdn$150 million. The IPSs were sold at a price of Cdn$10.55 per IPS for gross proceeds of Cdn$90 million and Cdn$60 million aggregate principal amount of debentures were issued. The IPSs and debentures were sold on a bought deal basis to a syndicate of underwriters. We used the net proceeds in February 2007 to acquire all of the remaining interest of ArcLight and Caithness in Atlantic Holdings.

In December 2006, we completed a private placement of 8,600,000 IPSs and Cdn$3.0 million principal amount of separate subordinated notes to three institutional investors. In February 2007, we used the net proceeds of the private placement to increase our ownership in Atlantic Holdings to 100%.

In November 2008, we acquired a 100% ownership interest in Auburndale Power Partners, L.P, which owns the Auburndale project, for a purchase price of approximately $140.0 million. The acquisition was funded with cash on hand, a $55 million borrowing under our credit facility and non-recourse acquisition debt of $35 million. The non-recourse acquisition debt associated with this transaction amortizes fully over the remaining term of the project's power purchase agreement, which expires in 2013. The borrowing under the credit facility was repaid in 2009.

In the first quarter of 2009, we transferred our remaining net interest in Onondaga Cogeneration Limited Partnership, at net book value, into a 50% owned joint venture, Onondaga Renewables, LLC, which is engaged in the redevelopment of the Onondaga project into a 40 MW biomass power plant.

In March 2009, we acquired a 40% equity interest in Rollcast Energy, Inc., a North Carolina corporation. Rollcast is a developer of biomass power plants in the southeastern U.S. with a number of additional 50 MW projects in various stages of development. We agreed to invest $2.0 million in March 2010 to increase our ownership interest in Rollcast to 60%. Under the terms of the agreement, $1.2 million of the investment was made in March 2010 and the remaining $0.8 million was made in April 2010. As a result of this additional investment, we began to consolidate our investment in Rollcast beginning March 1, 2010. We have the option, but not the obligation, to invest directly in biomass power plants developed by Rollcast.

In October 2009, we agreed to pay ArcLight an aggregate of $15 million to terminate its management agreement with us, satisfied by a payment of $6 million on the termination date of December 31, 2009, and additional payments of $5 million, $3 million and $1 million on the respective first, second and third anniversaries of the termination date. In connection with the termination of the management agreements, we hired all of the then-current employees of Atlantic Power Management and entered into employment agreements with its officers.

In December 2009, we issued, in a public offering, 6.25% convertible unsecured subordinated debentures due March 15, 2017, the 2009 Debentures, at a price of Cdn$1,000 per debenture for total gross proceeds of Cdn$86.25 million. The 2009 Debentures are convertible at any time, at the option of the holder, into approximately 76.9231 common shares per Cdn$1,000 principal amount of the 2009 Debentures, representing a conversion price of Cdn$13.00 per common share. Approximately Cdn$42.9 million of the net proceeds from the offering were used to redeem our 11% subordinated notes. The remainder of the net proceeds was made available to fund growth opportunities including biomass development and for general corporate purposes.

**RECENT DEVELOPMENTS**

On July 2, 2010, we acquired a 27.6% equity interest in Idaho Wind Partners 1, LLC (“Idaho Wind”) for approximately $40.0 million. Idaho Wind recently completed construction of a 183 MW wind power project located near Twin Falls, Idaho. Idaho Wind has 20-year PPAs with Idaho Power Company. Our investment in Idaho Wind was funded with cash on hand and a $20.0 million borrowing under our credit facility, which was subsequently paid in full in November 2010. We made a short-term $22.8 million loan to Idaho Wind to provide temporary funding for construction of the project until a portion of the project-level construction financing is completed. See additional details on page 28. Member loans will be paid down with a combination of excess proceeds from the federal stimulus cash grant after repaying the cash grant loan facility, funds from a third closing for additional project-level debt, and project cash flow. The federal stimulus grant is expected in the second quarter of 2011 and a third closing is expected by the end of the year. As of March 18, 2011, $5.1 million of the loan has been repaid. Our investment in Idaho Wind is accounted for under the equity method of accounting.

On October 20, 2010, we completed a public offering of 6,029,000 common shares, including 784,000 common shares issued pursuant to the exercise in full of the underwriters’ over-allotment option, at a price of $13.35 per common share. We received net proceeds from the common share offering, after deducting the underwriting discounts and expenses, of approximately $75.3 million.

On October 20, 2010, we also completed the closing of a public offering of Cdn$80.5 million aggregate principal amount of convertible unsecured subordinated debentures at a price of Cdn$1,000 per debenture, including Cdn$10.5 million aggregate principal amount of debentures pursuant to the exercise in full of the underwriters’ over-allotment option. The debentures bear interest at a rate of 5.60%, and will mature on June 30, 2017, unless earlier redeemed. The debentures are convertible into our common shares at an initial conversion rate of 55.2486 common shares per Cdn$1,000 principal amount of debentures, representing an initial conversion price of approximately Cdn$18.10 per common share (equivalent to US$18.03 per common share). We received net proceeds from the debenture offering, after deducting the underwriting discounts and expenses, of approximately Cdn$76.1 million ($74.6 million). The net proceeds from these offerings were used as follows:
(i) approximately US$20.0 million to repay indebtedness incurred under our credit facility entered into in June 2010 to partially fund acquisition of a 27.6% equity interest in Idaho Wind, and
(ii) approximately US$75.0 million to fund an investment in the Piedmont Green Power project for substantially all of the equity interest in the project. Any remaining net proceeds were used to fund the Cadillac acquisition and for general corporate purposes.

In November 2010, we closed the construction and term financing for the Piedmont Green Power, LLC ("Piedmont") project, a 53.5 MW biomass project located in Barnesville, Georgia and we agreed to invest approximately $75.0 million in the project to own substantially all of the equity interests. Construction of the project commenced immediately following the financial closing. The Piedmont Green Power project has a 20-year PPA with Georgia Power Company which includes an adjustment related to the cost of biomass fuel for the plant.

On December 20, 2010, we closed the acquisition of 100% of the membership interests in Cadillac Renewable Energy, LLC ("Cadillac"), a 39.6 MW biomass-fired generating facility located in Cadillac, Michigan that has been operating since 1993. The purchase price of approximately $80.0 million was funded by $37.0 million using a portion of the cash raised in the public equity and convertible debenture offerings in October 2010 and $43.0 million of assumed non-recourse, project-level debt.

**OUR 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 public convertible debentures in Canada. We have also issued private equity 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 1,962 MW, and our net ownership interest in the electric generation capacity of these projects is approximately 878 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.

- ***Stability of project cash flow.*** Each of our power generation projects currently in operation has been in operation for over ten years, except for the Idaho Wind Power project, portions of which commenced commercial operation in December 2010. 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 PPA(s), fuel supply agreement(s) 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, Power Plant Management Services and Babcock and Wilcox Power Generation Group, Inc. operate projects representing approximately 45%, 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 7% of the net electric generation capacity of our power generation projects.

## OUR OBJECTIVES AND BUSINESS STRATEGY

Our objectives include maintaining the stability and sustainability of dividends to shareholders and to maximize the value of our company. In order to achieve these objectives, we intend to focus on enhancing the operating and financial performance of 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 2011 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.

## POWER INDUSTRY OVERVIEW

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

In the independent power generation sector, electricity is generated from a number of energy sources, including natural gas, coal, water, waste products such as biomass (e.g., wood, wood waste, agricultural waste), landfill gas, geothermal, solar and wind. According to the North American Electric Reliability Council's Long-Term Reliability Assessment, published in December 2009, summer peak 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**

Our 13 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.

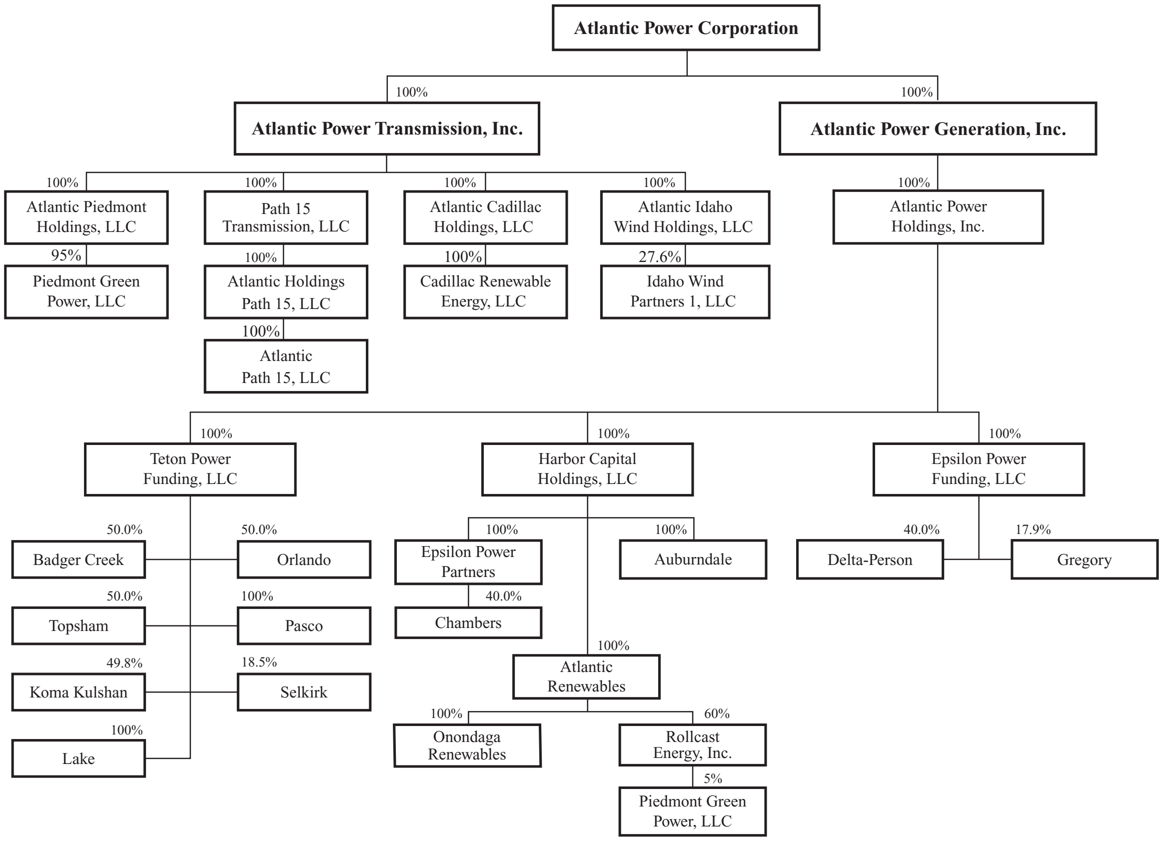
## OUR POWER PROJECTS

The following table outlines our portfolio of power generating and transmission assets in operation and under construction as of March 18, 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] | 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] | A-[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 | A- |
| | | | | | 9 | Sherwin Alumina | 2020 | NR |
| Topsham[10] | Maine | Hydro | 14 | 50.00% | 7 | Central Maine Power | 2011 | BBB+ |
| Badger Creek | California | Natural Gas | 46 | 50.00% | 23 | Pacific Gas & Electric | 2011[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 | PNM | 2020 | BB- |
| Cadillac | Michigan | Biomass | 40 | 100.00% | 40 | Consumers Energy | 2028 | BBB- |
| Idaho Wind[12] | Idaho | Wind | 183 | 27.56% | 50 | Idaho Power Co. | 2030 | BBB |
| Piedmont[13] | 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 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, who then pays owners of Transmission system rights, such as Path 15, in accordance with its annual revenue requirement approved every three years by 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 California Independent System Operator imposes minimum credit quality requirements for any participants rated A or better unless collateral is posted per the California Independent System Operator imposed schedule.
(7) Upon the expiry of the Reedy Creek PPA, the associated capacity and energy will be sold to PEF.
(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. For further details, see project description.
(10) We currently own our interest in this project as a lessor, but our lessor interest is subject to a purchase and sale agreement entered into with a third party on February 28, 2011.
(11) Expect an interim agreement to be entered into while details of a long-term agreement are worked out.
(12) Project just reached commercial operations and operating at initially reduced start-up levels.
(13) Project currently under construction and is expected to be completed in late 2012.

The following corporate organization chart includes all of our operating and development projects:




Our projects are organized into the following six business segments:

- Auburndale
- Lake
- Pasco
- Chambers
- Path 15
- Other Project Assets

**Auburndale segment**

*General description*

The Auburndale segment consists of a 155 MW dual-fired (natural gas and oil), combined-cycle, cogeneration plant located in Polk County, Florida, which commenced operations in July 1994. We own 100% of the Auburndale project, which is a "qualifying facility" (or "QF") under the rules promulgated by FERC. We acquired Auburndale from ArcLight Energy Partners Fund I, L.P. and Calpine Corporation in a transaction that was completed on November 21, 2008.

Auburndale is located on an 11-acre site in the City of Auburndale, Florida. Capacity and energy from the project is sold to Progress Energy Florida, Inc. ("PEF") under three PPAs expiring at the end of 2013. Auburndale typically operates during on-peak periods. Steam is supplied to Florida Distillers Company and Cutrale Citrus Juices USA, Inc. The Florida Distillers steam agreement is renewed annually, and the Cutrale Citrus Juices steam agreement expires in 2013.

Auburndale has non-recourse debt outstanding of $21.7 million as of December 31, 2010 which is required to be fully amortized over the term of its PPAs expiring in 2013. See "Project-level debt" on page 72 of this Form 10-K for additional details. Atlantic Power has provided letters of credit in the total amount of $13.4 million to support certain Auburndale obligations: $5.5 million to support its debt service reserve, $4.4 million to support its PPAs, and $3.5 million to support its fuel supply agreement.

*Power purchase agreements*

Auburndale sells capacity and electricity to PEF under three PPAs each of which expires on December 31, 2013. Under the largest of the PPAs, Auburndale sells 114 MW of capacity and energy. An additional 17 MW of committed capacity is sold under two identical 8.5 MW agreements with PEF. Revenue from the sale of electricity under the three PPAs consists of capacity payments based on a fixed schedule of prices, and energy payments. Capacity payments under the largest PPA are dependent on the plant maintaining a minimum on-peak capacity factor of 92 percent on a rolling twelve-month average basis. On-peak capacity factor refers to the ratio of actual electricity generated during periods of peak demand to the capacity rating of the plant during such periods. The project has achieved the minimum on-peak capacity factor continuously since commercial operation. Capacity payments under the smaller two agreements are dependent on the project maintaining a minimum on-peak capacity factor of 70 percent. Energy payments under the largest PPA are comprised of a fuel component based on the cost of coal consumed at two PEF-owned coal-fired generating stations and a component intended to recover operating and maintenance costs. Energy payments under the smaller two agreements are based on the lesser of PEF's actual avoided energy cost or an energy price index based on the cost of fuel burned at a specific coal-fired power plant owned by TECO.

Auburndale entered into an agreement with TECO to transmit electric energy from the project to PEF. The agreement expires in 2024, unless extended as provided for in the agreement. Auburndale's cost for these services is based on a contractual formula derived from TECO's cost of providing such services.

*Steam sales agreements*

Auburndale provides steam to Florida Distillers and Cutrale Citrus Juices under two separate steam purchase agreements. The Florida Distillers agreement automatically extends on an annual basis, and can be terminated by either party with 90 days notice. The Cutrale Citrus Juices agreement terminates on December 31, 2013 and contains automatic two-year renewal terms.

*Fuel supply arrangements*

Auburndale receives the majority of its required natural gas through a gas supply agreement with El Paso Merchant Energy, L.P. that expires on June 30, 2012. Under the agreement, El Paso provides a fixed amount of gas on a daily basis. The gas price escalates annually and is below current market prices. At historic utilization rates, the gas supplied under the El Paso contract has accounted for approximately 80% of the gas required by the project under its PPA commitments and the remaining required fuel is purchased at spot prices.

The required natural gas for the project is delivered through firm gas transportation agreements with Central Florida Gas Company ("Florida Gas") and Florida Gas Transmission Company and is transported through the gas distribution system owned by Peoples Gas Transmission, Inc. ("Peoples Gas"). The gas transportation agreements are co-terminous with the PPAs, expiring on December 31, 2013.

During the term of the gas supply agreement, approximately 80% of the natural gas required to fulfill the project's PPAs is purchased at fixed prices. The remainder of the natural gas is purchased on the spot market. As a result, the project's operating margin is exposed to changes in spot market natural gas prices because the PPAs do not pass through those price changes to PEF. In order to mitigate this risk, Auburndale has entered into a series of financial swaps that effectively fix most of the price of natural gas to be purchased. See Item 7A "Quantitative and Qualitative Disclosure About Market Risk" for a summary of the hedge position related to natural gas requirements at Auburndale.

We will continue to periodically analyze whether to execute further hedge transactions intended to mitigate natural gas price exposure at Auburndale through the expiration of the PPAs with PEF.

*Operations & maintenance*

The Auburndale project is operated and maintained by an affiliate of Caithness. In 2006, Auburndale entered into a maintenance agreement with Siemens Energy, Inc. for the long-term supply of certain parts, repair services and outage services related to the gas turbine. The term of the maintenance agreement is dependent on the timing of completion of a certain number of maintenance inspections. The final maintenance event under the agreement is scheduled for late 2012, with the final monthly payment under the agreement scheduled for September 2013.

*Factors influencing project results*

Auburndale derives a significant portion of its revenue through capacity payments received under the PPAs with PEF. In the event the project's on-peak capacity factor falls below a specified level, capacity payments will be adjusted downward or terminated altogether. Since it began commercial operation in 1994, the project has received full capacity payments.

The energy portion of Auburndale's revenue under the PPA with PEF is impacted by changes in the price of coal used by two of their power plants in Florida. Because these power plants secure a significant portion of their coal through contracts of varying lengths, the price of coal burned at those plants does not move in tandem with changes in spot coal prices.

**Lake segment**

*General description*

The Lake segment consists of a 121 MW dual-fuel, combined-cycle QF cogeneration plant located in Umatilla Florida, which began commercial operation in July 1993. We own 100% of the Lake project. In late 2007, the existing combustion turbines at the facility were upgraded to increase their efficiency by approximately 4% and output from 110 MW to 121 MW.

The Lake project is located on a 16-acre site leased from an adjacent citrus processing facility in Umatilla, Florida. Lake sells all of its capacity and electric energy to Progress Energy Florida, Inc. ("PEF") under the terms of a PPA expiring in July 2013. The project is generally operated as a mid-merit facility typically running during peak hours daily. Steam is sold to Citrus World, Inc. for use at its citrus processing facility and is also used to make distilled water in distillation units which is sold to various parties.

The Lake project does not have any debt outstanding. Atlantic Power has provided a $4.3 million letter of credit in favor of PEF to support the Lake project's obligations under its PPA.

*Power purchase agreement*

Electricity is sold to PEF pursuant to a PPA that expires on July 31, 2013. Revenues from the sale of electricity consist of a fixed capacity payment and an energy payment. Capacity payments are subject to the project maintaining a capacity factor of at least 90% during on-peak hours (11 hours daily), on a 12-month rolling average basis. Lake is subject to reductions in its capacity payment should it not achieve the 90% on-peak capacity factor. The project generally has achieved the minimum on-peak capacity factor continuously since commercial operation. Energy payments are comprised of a fuel component based on the cost of coal consumed at two PEF-owned coal-fired generating stations, a component intended to recover operations and maintenance costs, a voltage adjustment and an hourly performance adjustment.

*Steam sales agreement*

The Lake project provides steam to Citrus World under a steam purchase agreement that expires in 2013. The project also supplies steam to an affiliate that uses steam to make distilled water, which is sold to unaffiliated third parties.

*Fuel supply arrangements*

The natural gas requirements for the facility are provided by Iberdrola Renewables, Inc. and TECO Gas Services, Inc. ("TGS"). Both the Iberdrola and TGS agreements contain market index based prices, commenced on July 1, 2009 and expire on July 31, 2013. Natural gas is transported to the project from supply points in Texas, Louisiana and Mississippi to Florida under contracts with Peoples Gas System, Inc.

*Operations & maintenance*

The Lake project is operated and maintained by an affiliate of Caithness. Lake also has a long-term services agreement and a lease engine agreement in place with General Electric ("GE"). The long-term services agreement provides for planned and unplanned maintenance on the two gas turbines at the plant. Under the lease engine agreement, GE rapidly provides temporary replacement natural gas turbines to the project to support operations when the project's turbines are removed from the site for significant maintenance.

*Factors influencing project results*

The Lake project derives a significant portion of its operating margin through capacity revenues received under the PPA with PEF. In the event the facility's on-peak capacity factor falls below a specified level, capacity payments will be adjusted downward, although the project has rarely experienced such reductions. During the term of the current gas supply agreement, effective July 1, 2009, Lake's operating margins are exposed to changes in natural gas prices through the end of the PEF PPA in 2013. As a result, we have entered into a series of financial swaps that effectively fix most of the price of natural gas required by Lake, thereby substantially mitigating fuel price risk. See Item 7A "Quantitative and Qualitative Disclosures About Market Risk" for a summary of the hedge position related to natural gas requirements at Lake.

We will continue to analyze whether to execute further hedge transactions to mitigate natural gas price exposure at Lake through expiration of the PPA with PEF.

The energy portion of Lake's revenue under the PPA with PEF is impacted by changes in the price of coal used by two of their power plants in Florida. Because these power plants secure a significant portion of their coal through contracts of varying lengths, the price of coal burned at those plants does not move in tandem with changes in spot coal prices.

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

**Pasco segment**

*General description*

The Pasco segment consists of the 100% owned Pasco project, a 121 MW dual fuel, combined-cycle cogeneration plant located in Dade City, Florida, which began commercial operations in 1993 as a QF. With the expiration of the original PPA with PEF in 2008, and the commencement of the tolling agreement with TECO in 2009, Pasco self-certified with the FERC as an exempt wholesale generator and was no longer required to maintain QF status. The project owns the 2.7 acre site approximately 45 miles north of Tampa, Florida.

*Power purchase agreement*

Electricity is sold to TECO pursuant to a tolling agreement that commenced on January 1, 2009 and expires on December 31, 2018. Under the tolling agreement, TECO purchases the project's capacity and energy conversion services. Pasco converts fuel supplied by a TECO affiliate into electricity. Revenues consist of capacity payments, start-up charges, variable payments based on the amount of electricity generated and heat rate bonus payments based on the actual efficiency of the plant versus the contract efficiency. Atlantic Power has provided a $10 million letter of credit in favor of TECO to support the project's obligations under the tolling agreement.

In exchange for obtaining the right to sell any potential excess emissions allowances from the plant, TECO accepted financial responsibility for any future costs associated with obtaining additional allowances, offsets or credits required due to changes to environmental laws, including state or federal carbon legislation.

*Fuel supply arrangements*

Under the terms of the tolling agreement, TECO is responsible for the fuel supply and is financially responsible for fuel transportation to the project.

*Operations & maintenance*

The Pasco project is operated and maintained by an affiliate of Caithness. Pasco also has a services agreement and a lease engine agreement in place with GE. The services agreement provides for discounts for planned and unplanned maintenance on the project's two natural gas turbines, and commits the project to use GE for gas turbine maintenance activities. Under the lease engine agreement, GE rapidly provides temporary replacement natural gas turbines to the project to support operations when the project's turbines are removed from the site for significant maintenance.

*Factors influencing project results*

The Pasco project derives the majority of its revenues under the tolling agreement with TECO through capacity payments. In the event the project does not maintain certain levels of availability, the capacity payments will be reduced. Based on historical performance, we expect the project to continue to exceed the availability requirement of 93% in the summer and 90% in the winter. A portion of the project's operating margin is based on three variable payments from TECO, consisting of a variable operation and maintenance charge, a start charge and a heat rate bonus. As a result, the project achieves a variable margin during periods of operation; and as a result, the level of variable margin is impacted by how much the plant is called on to produce electricity.

**Chambers segment**

*General description*

The Chambers segment consists of our 40% equity investment in the Chambers project, a 262 MW pulverized coal-fired cogeneration facility located at the E.I. du Pont de Nemours and Company Chambers Works chemical complex near Carney's Point, New Jersey, which began commercial operation in March 1994 as a QF. Affiliates of Goldman Sachs Group, Inc. and Energy Investors Funds, an established private equity fund manager that invests in the U.S. energy and electric power sector, in the aggregate hold 60% of the general partner interests. Chambers sells electricity to ACE under two separate power purchase agreements, a "Base PPA" and a power sales agreement. Historically, the project has operated as a baseload plant, however, during periods of low energy market pricing, the facility has run at partial or minimum load. Steam and electricity are sold to DuPont pursuant to an energy services agreement. The project site is leased from DuPont. Under the terms of the ground lease, DuPont has a right to purchase the project within 60 days of the lease expiration in 2024, or upon earlier termination of the lease, at fair market value.

Chambers financed the construction of the project with a combination of term debt due March 31, 2014 and New Jersey Economic Development Authority bonds due July 1, 2021. The term loan amortizes over its remaining term, while the bonds are repayable at maturity. Both are non-recourse to Atlantic Power. Our 40% share of the total debt outstanding at the Chambers project as of December 31, 2010 is $75.0 million. See "Project-level debt" on page 72 of this Form 10-K for additional details.

Epsilon Power Partners, L.P., our wholly-owned subsidiary, directly owns our interest in Chambers. Epsilon has outstanding debt of $36.5 million as of December 31, 2010 which fully amortizes by its final maturity in 2019 and is non-recourse to Atlantic Power. See "Project-level debt" on page 72 of this Form 10-K for additional details.

*Power purchase agreements*

Base PPA

The 30-year term of the Base PPA with ACE expires in 2024. ACE has agreed to purchase 184 MW of capacity and has dispatch rights for energy of up to 187.6 MW during the summer season (May 1 to October 31) and 173.2 MW during the winter season (November 1 to April 30) and a minimum dispatch level of 46 MW. The project must be available to deliver power to ACE at 90% of the average availability rate of a specific group of mid-Atlantic generating stations, which in 2010 was approximately 86.0%. Capacity prices are determined using a fixed price with a capacity factor adjustment. The energy payment under the Base PPA is divided between on-peak and off-peak periods and linked to a coal index that is identical to the project's coal supply contract escalation provisions. Chambers is guaranteed a minimum energy payment equivalent to 3,500 hours of operation per contract year, whether or not it has dispatched that many hours, provided the project is available for energy production for at least 3,500 hours during the course of the contract year.

DuPont energy services agreement

DuPont purchases all its electrical needs for its Chambers Works chemical complex from the Chambers project, subject to a peak requirement of 40 MW, under the energy services agreement ("ESA"). The initial term of the agreement expires in 2024 but will continue thereafter unless terminated by at least 36 months prior written notice. The electricity sold under the ESA contains a fixed price, which is adjusted quarterly by the lesser of either: (i) the price of coal delivered to the facility; and (ii) the change in ACE's average retail rate.

In December 2008, Chambers filed suit against DuPont for breach of the ESA related to unpaid amounts associated with disputed price change calculations for electricity. DuPont subsequently filed a counterclaim for an unspecified level of damages. In February 2011, Chambers received a favorable ruling from the court on its summary judgment motion as to liability. The court's decision included a description of the pricing methodology that is consistent with the project's position. In the event the dispute cannot be resolved through settlement, a trial to determine the level of damages is expected in the second quarter of 2011.

Power sales agreement

Energy generated at the Chambers project in excess of amounts delivered to ACE under the Base PPA and to DuPont under the ESA is sold to ACE under a separate power sales agreement (the "PSA"). Under this agreement, energy that ACE does not find economically attractive at the Base PPA's energy rate, but which may be cost effective to sell into the spot market ("Undispatched Energy"), may be self-scheduled by the project to capture additional profits. Margins on Undispatched Energy sales are shared between ACE (40%) and the project (60%). Excess energy not committed to ACE under the Base PPA (above 188 MW in the summer months and 173 MW in the winter months) and not called upon by DuPont under the ESA may also be sold into the market under a similar margin sharing arrangement (30% to ACE and 70% to Chambers). The ESA also provides for the sale by Chambers into the market via annual auctions of capacity not contracted under the Base PPA pursuant to the same margin sharing arrangement (30% to ACE and 70% to Chambers).

The PSA expired in July 2010 and we entered into a replacement agreement on similar terms that will expire December 31, 2011.

*Steam sales agreement*

Some of the steam generated at the Chambers project is sold to DuPont under the ESA, which expires in 2024, but will continue in effect thereafter unless terminated by either party on at least 36 months prior notice. The agreement requires steam to be provided to and budgeted by DuPont up to specified peak steam requirement levels that vary throughout the year. DuPont may purchase steam in excess of the peak steam requirement from any third party, subject to Chambers' right of first refusal to provide steam at the same price. After 2014, DuPont has the option to construct and operate its own steam generation facility for steam volumes in excess of DuPont's take obligations under the ESA, if it can demonstrate that it can generate steam more economically than the project. Chambers has the right to provide steam at an equivalent price as the steam generation project proposed by DuPont. DuPont is required to purchase a minimum quantity of steam necessary for the project to maintain its status as a QF. The steam price is subject to quarterly adjustments based on the price of coal delivered to the project. DuPont has the option in certain circumstances to take over operation of the steam facility in the event of prolonged failure to deliver steam.

*Fuel supply arrangements*

Coal is supplied to the Chambers project pursuant to a coal purchase agreement with Consol Energy Inc. ("Consol"), which expires in 2014 and is subject to a five to ten-year renewal based on good faith negotiations. The agreement governs the sale of coal (including transportation) to the project and the disposal of related ash. Consol is obligated to supply the entire coal requirements for the project, which may include stockpiling. The price escalator under the Base PPA with ACE uses the same index as the coal supply agreement (average coal cost of 25 mid-Atlantic region coal power plants), effectively passing through changes in coal prices to ACE.

*Operations & maintenance*

Operations and maintenance of the Chambers project is performed pursuant to an agreement with Power Plant Management Services, LLC ("PPMS"), which expires in April 2014. Thereafter, the agreement will be automatically renewed for periods of five years until terminated by either party on six months notice. PPMS is paid a base annual fee in addition to cost reimbursement. PPMS is also eligible for performance fees based on facility net availability, efficiency and excess energy optimization, and is eligible for an additional management performance bonus. The majority owner of the project transferred management services from Cogentrix Energy, Inc. to PPMS in December 2010.

*Regional greenhouse gas initiative*

With New Jersey's implementation of the Regional Greenhouse Gas Initiative on January 1, 2009, the Chambers project was required to obtain carbon dioxide ("$CO_2$") allowances in an amount corresponding to the $CO_2$ emissions of the facility. Previously in 2008, the State of New Jersey passed legislation that provided for the sale of $CO_2$ allowances at the price of $2.00 per allowance to certain generating facilities which were certified by the New Jersey Department of Environmental Protection ("NJDEP"). Chambers received this certification from the NJDEP in late 2009. The project maintains the required level of $CO_2$ allowances through a combination of purchases in the quarterly Regional Greenhouse Gas Initiative auctions, broker purchases and purchases from the NJDEP.

*Factors influencing project results*

The Chambers project derives a significant portion of its operating margin through capacity revenues received under the Base PPA. In the event the facility does not maintain a minimum level of availability under the Base PPA, the project's capacity payments from ACE would be reduced or eliminated, although it has never experienced such a reduction since commencing operation in 1994. Energy sales under the Base PPA are expected to generate positive margins due to the effective hedging of energy prices and coal costs through the use of identical indexing in the energy payment under the Base PPA and the coal prices under the coal supply contract. While the indexing is identical, adjustments to the energy price under the Base PPA occur annually, whereas coal price adjustments occur quarterly.

During periods of low spot market electricity prices, energy sales margins may be negatively impacted due to the pricing structure under the Base PPA and PSA. ACE will reduce purchases under the Base PPA to the minimum requirement of 46 MW when the spot electricity price is below the price under the Base PPA. When spot market prices drop below the Base PPA price, but exceed the project's variable production cost, ACE pays for energy based on the PSA, under which a portion of the margin above the project's production cost is shared with ACE. In the unusual situation when the spot electricity price is in excess of the Base PPA but less than the project's variable production cost (which may occur during off-peak periods), Chambers is required to sell energy to ACE at below its production cost. In some cases, the project is further negatively impacted by the facility's reduced fuel efficiency while operating at partial load.

**Path 15 segment**

*General description*

The Path 15 segment consists of our ownership of 72% of the transmission system rights in the Path 15 project, an 84-mile, 500-kilovolt transmission line built along an existing transmission corridor in central California. The Path 15 project commenced commercial operations in 2004. The Path 15 project facilitates the movement of power from the Pacific Northwest to southern California in the summer months and from generators in southern California to northern California in the winter months. The transmission system rights entitle us to receive an annual revenue requirement that is regulated by the FERC which established a 30-year regulatory life for the project in connection with its first rate case. The annual revenue requirement is collected from California utilities and remitted to owners of transmission system rights by the California Independent System Operator.

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

The California Independent System Operator ("CAISO") is a not-for-profit corporation that acts as a clearinghouse to settle third-party transactions involving the purchase and sale of power in California. Owners of transmission assets such as Path 15 must place their assets under the operational control of the California Independent System Operator by entering into a standard transmission control agreement with them. In general, the California Independent System Operator coordinates the dispatch of power generation and manages the reliability of, and provides open access to, the transmission grid.

Three of our wholly-owned subsidiaries have incurred non-recourse debt relating to our interest in the Path 15 project. Total debt outstanding at the Path 15 project as of December 31, 2010 is $153.9 million, which is required to fully amortize over their remaining terms through 2028. See "Project-level debt" on page 72 of this Form 10-K for additional details. We have provided letters of credit totaling $8.0 million to support these debt service obligations.

*Annual revenue requirement—FERC triennial rate case*

The revenue collected by Path 15 is regulated by the FERC on a cost-of-service rate base methodology. Path 15 files a rate case with the FERC every three years to establish its revenue requirement for the next three-year period. The revenue requirement includes all prudently incurred operating costs, depreciation and amortization, taxes, and a return on capital.

In February 2011, we filed a rate application with the FERC to establish Path 15's revenue requirement for the 2011 - 2013 period. Similar to our rate application filed with the FERC for the three-year period ending 2010, we expect parties to file protests and interventions to become parties to the rate case proceeding. In the event we cannot negotiate a settlement with intervenors, which was accomplished in the last two rate cases, a trial type evidentiary hearing will be held.

*Factors influencing project results*

The primary factor influencing the Path 15 project results is its FERC-regulated revenue requirement. Under the FERC's cost-of-service methodology, all prudently incurred expenses are permitted to be recovered in the revenue requirement including costs of the rate case itself every three years. Cash distributions to us could be adversely impacted if the FERC does not continue to approve a return on equity of at least 13.5% in future rate cases.

**Other project assets segment**

**Orlando project**

*General description*

The Orlando project, a 129 MW natural gas-fired combined-cycle cogeneration facility located in an industrial park near Orlando in Orange County, Florida, commenced commercial operation in 1993 as a QF. We own a 50% interest in the project and Northern Star Generation, LLC ("Northern Star") owns the remaining 50% interest. The project is situated on a four acre site located adjacent to an air separation facility owned by Air Products and Chemicals, Inc. ("Air Products and Chemicals"), which serves as the project's steam customer. Orlando sells all of its electricity to PEF and Reedy Creek Improvement District ("Reedy Creek") under long-term PPAs, and also sells chilled water produced using steam from the project to Air Products and Chemicals. The Orlando project typically operates as a baseload plant. Both we and Northern Star have provided letters of credit in the amount of $1.6 million each in support of the project's obligations under the PEF PPA.

*Power purchase agreements*

Progress Energy Florida

Orlando sells electrical capacity and energy to PEF under a PPA that expires on December 31, 2023. The project is obligated to sell and deliver a committed capacity of 79.2 MW and has committed to a 93% on-peak capacity factor. Orlando receives a monthly capacity payment based on achieving the on-peak capacity factor and a monthly energy payment based on the total amount of electric energy actually delivered to PEF. The capacity payment escalates at 5.1% annually and is reduced if the facility's on-peak capacity factor is below 93%, on a 12-month rolling average basis. Energy payments are comprised of a fuel component based on the cost of coal consumed at two PEF-owned coal-fired generating stations, an operations and maintenance component, a voltage adjustment and an hourly performance adjustment. Off-peak energy prices are based on the on-peak spot market energy price discounted by 10%.

On August 4, 2009, PEF provided notice to Orlando that the committed capacity under its PPA would be increased to 115 MW upon expiration of the Reedy Creek PPA in 2013, upon meeting certain conditions.

Reedy Creek Improvement District

Orlando sells electrical capacity and energy to Reedy Creek, a municipal district serving the Walt Disney World complex, under a PPA that expires in 2013. Orlando is obligated to sell and deliver 35 MW of electricity and has committed to a 93% average on-peak capacity factor. Orlando receives a monthly capacity payment based on the actual average on-peak capacity factor and a monthly energy payment based on the total amount of electric energy actually delivered to Reedy Creek. The PPA may be extended for an additional ten-year term upon the consent of both parties. The capacity payment is fixed at a rate that escalates at 4.5% annually and is based upon achieving a 93% average on-peak capacity factor, calculated on a three-year rolling average basis. The agreement provides both incentive and penalty provisions for performance above and below a 93% average on-peak capacity factor, respectively. Reedy Creek also reimburses Orlando for a portion of the reservation charges associated with the project's firm gas transportation agreement with Florida Gas. In 2005, Orlando executed an agreement with Reedy Creek for periodic sales of up to 15 MW of non-firm available energy at firm rates.

*Excess energy sales*

In 2006, Orlando executed a master purchase and sale agreement with Rainbow Energy Marketing Corporation ("Rainbow"). Under the agreement, Rainbow markets up to 15 MW of non-firm energy at spot market rates subject to the profitability of such sales. The arrangements with Rainbow can be terminated by either party upon 30 days notice.

*Steam sales agreement*

Orlando entered into an agreement with a subsidiary of Air Products and Chemicals to supply chilled water produced using steam from the project to its cryogenic air separation facility. Orlando does not have any minimum steam delivery requirements beyond the thermal and efficiency requirements required to maintain its QF status. Orlando is required to purchase its nitrogen requirements from Air Products and Chemicals, but does not have a minimum purchase requirement. Both the purchase price of nitrogen and the sale price of chilled water are at fixed prices that adjust based on the percentage increase/decrease in the producer price index.

Because of reduced demand for chilled water at Air Products and Chemicals during certain periods, and to ensure continued compliance with QF requirements, Orlando procured and installed water distiller units in 2009, and entered into contracts to provide the distilled water to unaffiliated third parties in the local area.

*Fuel supply arrangements*

Orlando buys natural gas from Orlando Power Holdings, LLC, which is indirectly owned by Northern Star, under an agreement expiring on December 31, 2013. Orlando Power has a back-to-back agreement for the purchase and supply of natural gas from Vastar Gas Marketing, Inc. ("Vastar"), which is a wholly-owned subsidiary of BP Energy Company. Under the agreement, which expires on December 31, 2013, Vastar is obligated to provide Orlando Power with its entire daily natural gas requirement. Orlando's purchase price is tied to the same coal-based and fixed escalators used for calculating the energy payments under the PPAs.

Affiliates of Orlando Power Holdings, LLC entered into co-terminous back-to-back agreements with Florida Gas for the delivery of natural gas to the project. Orlando has a contractual right to extend these agreements. Transportation costs under the agreements are determined by Florida Gas' rate schedule as filed with the FERC. These agreements provide for the transportation of up to 23,600 Mmbtu per day to the project.

*Operations & maintenance*

The Orlando project is operated and maintained by an affiliate of Northern Star under an operations and administrative services agreement expiring on December 31, 2023. The operator is compensated on a cost-reimbursement basis plus a fixed general and administrative charge. In addition, the operator is entitled to receive an incentive fee equal to a percentage of the excess of Orlando's operating cash flow after deducting originally anticipated maintenance capital and anticipated debt service. In 1997, Orlando also entered into a long-term maintenance agreement with Alstom Power Inc. for the long-term supply of hot gas path gas turbine parts, under which Alstom receives a monthly fee from the partnership and additional fees in certain circumstances.

*Factors influencing project results*

The Orlando project receives a significant portion of its revenues through capacity payments received under the PPA with PEF. In the event the facility's on-peak capacity factor falls below a specified level, capacity payments will be adjusted downward or eliminated. The energy payment under the PEF PPA largely consists of an energy component, which is adjusted based on the same coal index as used in the gas supply pricing.

The energy payment under the PPA with PEF includes a performance adjustment. During on-peak periods in which the market price for energy exceeds the PPA energy rate, for energy deliveries in excess of PEF scheduled capacity, the project receives the then as-available energy rate, determined according to regulatory methodology. Conversely, during on-peak periods when the project delivers less than the scheduled capacity, the project incurs negative performance adjustment charges corresponding to the difference between the then as-available energy rate and the PPA energy rate.

The Reedy Creek PPA also contains incentive and penalty provisions for performance above and below a specified capacity factor.

**Selkirk project**

*General description*

The Selkirk project is a 345 MW dual-fuel, combined-cycle cogeneration plant located in the Town of Bethlehem in Albany County, New York, which commenced commercial operation in 1994 as a QF. The project includes two units: Unit I (80 MW) currently sells electricity into the New York merchant market and Unit II (265 MW) sells electricity to Consolidated Edison Company of New York, Inc. (or "Con Ed"). The Selkirk project is typically operated as a mid-merit plant. The other partners include affiliates of Cogentrix, Energy Investors Funds, The McNair Group, and Fort Point Power LLC (an affiliate of Osaka Gas Energy America Corporation). Each of the partners has an interest in cash distributions by the project which changes when certain partners achieve a specified return on their equity contributions as set forth in the partnership agreement. We own: (i) 13.62% interest in the priority distributions up to a fixed semi-annual amount as described below; (ii) 19.94% interest on any distributions in excess of the priority distributions; and (iii) 17.7% of all distributions made after the last priority distribution is made, estimated to occur in 2012. If priority distributions are not made at the maximum amount, the unpaid amounts accumulate and are paid when funds are available in subsequent periods. As of December 31, 2010, our 13.62% share of unpaid priority distributions was $1.8 million. In addition to this accumulated amount, our share of the maximum semi-annual priority distributions in 2011 and 2012 is approximately $0.8 million and $0.7 million, respectively. The 15.7 acre project site is situated adjacent to a Saudi Arabia Basic Industries Corporation (or "SABIC") plastics manufacturing plant, which also purchases steam from the project. Selkirk leases the project site under a long-term lease from SABIC.

The Selkirk project has 8.98% first mortgage bonds outstanding. Our share of the outstanding amount of these bonds was $16.8 million as of December 31, 2010, which fully amortizes over the remaining term ending in 2012. See "Project-level debt" on page 72 of this Form 10-K for additional details.

*Power purchase agreements*

Since the expiration of Selkirk's agreement to sell 80 MW of capacity and energy from Unit I to National Grid in July 2008, Selkirk has been selling energy from Unit 1 into the New York merchant market. 265 MW of capacity and energy from Unit II is sold to Con Ed under a PPA that expires on September 1, 2014, subject to a ten-year extension at the option of Con Ed under certain conditions. It is not known whether Con Ed intends to exercise this option. The Unit II PPA provides for a capacity payment, a fuel payment, an operations and maintenance payment and a payment for transmission from the project to Con Ed. The capacity payment, a portion of the fuel payment, a portion of the operations and maintenance payment and the transmission payment are paid on the basis of plant availability.

*Steam sales agreement*

Selkirk sells steam generated at the project to the SABIC plastics manufacturing plant under an agreement that expires on September 1, 2014. Under the agreement, SABIC is not charged for steam in an amount up to the annual equivalent of 160,000 lbs/hr during each hour in which the SABIC plant is in production. SABIC pays the project a variable price for steam in excess of this amount. SABIC is required to purchase the minimum thermal output necessary for Selkirk to maintain its QF status.

*Fuel supply arrangements*

Selkirk buys natural gas for Unit I at spot market prices under a contract with Coral Energy Canada Inc. expiring on October 31, 2012. Selkirk has gas supply agreements for Unit II with Imperial

Oil Resources Limited, EnCana Corporation and Canadian Forest Oil Ltd., which expire on October 31, 2014.

The project also has long-term contracts for the transportation of Units I and II natural gas volume on a firm 365-day per year basis in place with TransCanada Pipelines Limited, Iroquois Gas Transmission System LP and Tennessee Gas Pipeline Company. The Unit I and Unit II gas transportation contracts expire on November 1, 2012 and November 1, 2014, respectively.

Natural gas that is not used by Selkirk to generate power under its gas supply arrangements may be remarketed. Units I and II have the capability to operate on fuel oil subject to certain limitations under the project's air permit and are able to switch fuel sources from natural gas to fuel oil and back without interrupting the generation of electricity.

*Operations & maintenance*

GE operates the Selkirk project under an agreement expiring on December 31, 2012. The agreement provides for a fixed fee, capital parts discounts, a pass-through of management costs and a performance bonus. Management services for Selkirk are provided by PPMS under an administrative services agreement that expires in September 2014. PPMS is entitled to compensation under the agreement which is subject to renegotiation every four years and provides for the full recovery of its actual costs and properly allocated overhead plus a reasonable fee which must be approved by all of the Selkirk partners. In August 2010, the partners consented to the transfer of management services from Cogentrix to PPMS.

*Regional greenhouse gas initiative*

In 2009, in order to comply with the Regional Greenhouse Gas Initiative, the project commenced purchasing $CO_2$ allowances in the quarterly Regional Greenhouse Gas Initiative auctions. Under the Regional Greenhouse Gas Initiative rules, a compliance period consists of three years, during which time the emitter is required to obtain allowances corresponding to its $CO_2$ emissions during the same period. New York State allocates a limited number of free allowances to generators that have long-term contracts. A portion of the project's annual requirement is met with these free allowances. In resolution of a lawsuit brought by an unaffiliated owner of another New York independent power plant in 2009 challenging New York's Regional Greenhouse Gas Initiative rules, a consent decree was finalized under which Con Ed reimburses the Selkirk project for the cost of additional allowances needed in excess of the free allowances allocated by New York through that term of the PPA.

*Factors influencing project results*

Energy produced by Unit I (80 MW) is sold at market prices based on the project's bid into the spot market. The project is therefore exposed to fluctuations in market energy prices which may impact Unit I energy sales margins. Under the PPA with Con Ed, the project receives significant capacity revenues based on meeting availability requirements and also receives an energy payment whenever Con Ed calls on Unit II (265 MW) to generate electricity. The energy payment is primarily dependent on the fuel price component, which is indexed predominantly to natural gas prices, but also has a small component based on oil prices.

In periods when Unit I or Unit II is not generating electricity, substantial volumes of natural gas are available to be re-sold. Depending on market prices when reselling compared to contract prices when the gas was nominated at the beginning of each month, the excess gas has been resold at significant positive margins and occasionally at a loss.

TransCanada transports natural gas for the project from Selkirk's suppliers in Empress, Alberta to the interconnection with Iroquois Gas Pipeline in eastern Ontario. Under "cost of service" tolling methodology established by the National Energy Board of Canada ("NEB"), TransCanada's tolls are determined by dividing its total annual operating costs by the projected volumes of gas transported. Due to a number of factors, the volumes shipped on TransCanada have decreased significantly over the last few years. In late 2010, TransCanada commenced settlement discussions with its shippers to determine, for the period 2011–2013, the toll for gas transportation from Empress to eastern Canada. Early in the rate making process in December, based on settlement discussions, TransCanada applied for interim tolls that would have represented a reduction from the level in 2010. However after subsequent TransCanada filings, the NEB approved interim tolls that temporarily reflect an increase from the level in 2010. The NEB has instructed TransCanada to submit its final 2011 toll application by May 2011. If TransCanada cannot negotiate a settlement with its major shippers by that time, the NEB will hold hearings to obtain the shipper's arguments and recommendations before it renders a final decision.

**Gregory project**

*General description*

The Gregory project is a 400 MW natural gas-fired combined cycle cogeneration QF located near Corpus Christi, Texas that commenced commercial operation in 2000. The Gregory project is owned by Gregory Power Partners, LP, a Texas limited partnership, and our ownership interest in Gregory Power is approximately 17%. The other owners are affiliates of JP Morgan Chase & Co. and John Hancock Life Insurance Company. Gregory currently sells approximately 345 MW of its capacity to Fortis Energy Marketing and Trading GP ("Fortis") and sells up to 33 MW of electric energy and capacity to Sherwin Alumina Company ("Sherwin"), which is owned by Glencore International AG, with the remainder sold in the spot market. The project is located on a site adjacent to Sherwin's production facility, which also serves as the project's steam customer. Gregory leases the land on which the project is located from Sherwin under an operating lease which expires in August 2035.

The Gregory project was financed, in part, with a non-recourse debt that matures in 2017 and is required to be amortized over its remaining term. Our share of the total debt outstanding at the Gregory project as of December 31, 2010 was $14.4 million. See "Project-level debt" on page 72 of this Form 10-K for additional details.

In November 2008, Gregory's managing partner discovered that the state authorization of the project's Prevention of Significant Deterioration Air Permit had lapsed due to a discrepancy in the representation of the renewal date of the state authorization by a consultant in 2002. The issue was self-reported to the Texas Commission of Environmental Quality ("TCEQ"). During the first quarter of 2009, Gregory submitted its initial draft permit application to the TCEQ, which deemed it administratively complete, and completed the technical aspects of the permitting process. In December 2009, TCEQ provided Gregory Power a draft of a new permit, and on March 15, 2010, TCEQ issued the new permit at emissions limits achievable by the project and not requiring the installation of additional emissions control equipment.

*Power purchase agreement*

Gregory sells 345 MW of its output to Fortis under a PPA that began on January 1, 2009 and expires December 31, 2013. Under the terms of the Fortis agreement, Fortis pays a fixed capacity payment based on a fixed capacity rate and an energy payment that is based on the price of natural gas at Houston Ship Channel and a contract heat rate. (Heat rate refers to the amount of energy that is required to generate one kilowatt hour of electricity.) Energy sales to Fortis consist of two tranches: a 234 MW "must-run" block and a 111 MW "dispatchable" block. The must-run block corresponds to the project's minimum energy output while satisfying Sherwin's electricity and steam requirements without the use of Gregory's auxiliary boilers. The dispatchable block is the portion of Gregory's output that can be scheduled at the option of Fortis as either energy, ancillary services or balancing energy. Credit support for the PPA consists of a $10 million letter of credit issued by ING which is backed by letters of credit from the project's partners, including a $1.7 million letter of credit provided by Atlantic Power.

*Steam sales agreement*

Gregory sells steam to Sherwin under an agreement that expires in 2020. Under the terms of the agreement, Gregory is the exclusive source of steam to Sherwin's alumina plant, up to a maximum of 1,500,000 lbs/hr.

*Fuel supply arrangements*

Gregory purchases natural gas under various short-term and long-term agreements. Gregory has the option of procuring 100% of its natural gas requirements from Kinder Morgan Tejas Pipeline, L.P., under a market-based gas supply agreement that expires in August 2012.

In March and June 2008, the project entered into pay fixed, receive floating, natural gas swap agreements with Sempra Energy Trading Corp. for the period January 2009 through December 2010. While Gregory has structured its power and steam sales agreements to mitigate the price risk between its fuel supply and electricity sales agreements, the project has some residual exposure to natural gas price risk due to the difference between the project's actual heat rate and the contractually guaranteed heat rate under the Fortis PPA. The swap agreements partially mitigated this natural gas price risk.

*Operations & maintenance*

An affiliate of Babcock and Wilcox Power Generation Group, Inc. is responsible for the operation and maintenance of the Gregory project under an agreement that terminates in July 14, 2015. The operator receives a fee for management of the facility (subject to escalation) and reimbursement of certain costs.

*Energy management services*

Tenaska Power Services, Co. ("Tenaska") provides Gregory with energy management services such as marketing excess power from the Project through the end of 2011. Tenaska optimizes Gregory's assets in the ancillary services market of the Electric Reliability Council of Texas, purchases natural gas for operations, provides scheduling services, provides back-office support and serves as Gregory's retail energy provider and qualified scheduling entity.

*Factors influencing project results*

The Gregory project derives a significant portion of its operating margin through energy revenues under its PPA with Fortis. Energy revenues are dependent on the price of natural gas at Houston Ship Channel and a contract heat rate. The project achieves a margin on its energy revenue due to the facility's actual heat rate being lower than the contractually guaranteed heat rate.

Gregory also receives a capacity payment under the Fortis PPA which is dependent on maintaining certain minimum performance requirements. The project's capacity payments are subject to reduction or elimination if it fails to meet these requirements. Due to a forced outage in 2009, the project only received 98% of the full capacity revenue. However, historically the project has met all of the performance standards under the Fortis PPA.

Gregory benefits from the heat rate differential between the heat rate of the facility and the contracted heat rate under the terms of the PPA with Fortis. The heat rate of the facility is impacted by the amount of steam that Sherwin is able to accept. If Sherwin's alumina plant were to discontinue operations or decrease production levels, it would have adverse impacts on the efficiency of the Gregory facility.

**Topsham project**

*General description*

The Topsham project is a 14 MW hydroelectric facility located on the Androscoggin River at the Pejepscot dam near Topsham, Maine which began commercial operation in 1987 as a QF. A 100% undivided interest in the Topsham project and a 100% undivided interest in the Topsham project site are owned by a financial institution, in its capacity as owner trustee for the benefit of Atlantic Power (50%) and DaimlerChrysler Services North America LLC (50%) as owner participants. Electricity is sold to the Central Maine Power Company ("CMP") under a PPA that expires in 2011.

The Topsham project is leased and operated by Topsham Hydro Partners Limited Partnership ("THP"), a Minnesota limited partnership. Pursuant to a sale and lease back transaction, THP leases both our interests in the project and in the project site until November 17, 2011. At the end of the lease term, THP has the option to renew the lease or acquire our share of the project and the project site.

On February 28, 2011, we entered into a purchase and sale agreement with a third party for the purchase of our lessor interest in the project. Closing of the transaction is expected to occur in the second quarter of 2011.

*Power purchase agreement*

Electrical output from the Topsham project is sold to CMP under a PPA that contains a fixed price schedule and terminates on December 31, 2011.

*Operations & maintenance*

THP operates the project and provides all general and administrative services for the project under an agreement in effect until the earlier of December 31, 2027 or upon THP becoming the owner of 100% of the project and the project site.

**Badger Creek project**

*General description*

The Badger Creek project is a 46 MW simple-cycle, cogeneration facility located near Bakersfield, California which began commercial operation in 1991 as a QF. The Badger Creek project is owned by Badger Creek Limited, L.P. ("Badger"), a Texas limited partnership in which we own a 50% partnership interest. Juniper Generation, LLC, which is indirectly owned by affiliates of ArcLight Capital Partners, LLC, owns the other 50% partnership interest. Electricity is sold to Pacific Gas & Electric Corporation ("PG&E") under a PPA expiring in 2011. The project typically operates in a baseload configuration. Steam is sold to OXY USA Inc. ("OXY"), an affiliate of Occidental Petroleum Corporation, under an agreement that expires in 2011. Badger leases the approximately 3.5 acre site for the Badger Creek project under a ground lease. The term of the lease expires in July 2021 and the parties may extend it for up to 10 additional one-year periods.

*Power purchase agreement*

Electricity generated by the Badger Creek project is purchased by PG&E under a PPA that expires in 2011. The PPA provides for monthly capacity and energy payments, and Badger is entitled to receive a performance bonus if the average on-peak capacity factor exceeds 85%. The energy price received under the PPA is linked to PG&E's interim "short-run avoided cost," as discussed below. Badger Creek has commenced discussions with PG&E regarding a new PPA. It is expected that these negotiations will not be completed before the expiry of the existing PPA, at which time the project will enter into a one-year interim agreement as provided for under the California Public Utilities Commission ("CPUC") regulations.

*Steam sales agreement*

Steam from the Badger Creek project is sold to OXY under an agreement which expires in 2011. The agreement provides for successive renewal terms of one year unless either party gives advance notice of termination. OXY utilizes the steam in its enhanced oil recovery operations to allow for more effective and efficient extraction of heavy crude oil. Subject to certain conditions, OXY has an obligation to buy steam under this agreement in an amount not less than the minimum requirements necessary to maintain the project's status as a QF. Although OXY is not currently purchasing any power from the project, the steam agreement allows for up to 1 MW of electricity to be sold to OXY.

*Fuel supply arrangements*

Natural gas is delivered to Badger Creek via a private pipeline that connects with the Kern River-Mojave Pipeline. The pipeline was constructed by a joint venture in which the project owns approximately 16.8% following the assignment of a portion of the interests in the joint venture in January 2010 to an affiliate of OXY. An affiliate of Juniper operates the pipeline. In October 2006, Badger entered into a gas supply agreement, including transportation, with Sempra Energy Trading Corporation. In March 2008, the gas agreement was extended to cover fuel procurements through April 30, 2011.

*Operations & maintenance*

Operations and maintenance for the Badger Creek project is performed by an affiliate of Juniper Generation, LLC under a fixed price operations and maintenance agreement. The agreement expires in April 2011. The operator receives a base monthly fee, which is adjusted annually. In addition, the agreement provides for incentive fees and penalties based on the project's availability. An affiliate of Juniper also provides all day-to-day management services required by the project and is paid a semi-annual fee for such management services based on a percentage of gross cash receipts of the project.

*Factors influencing project results*

The Badger Creek project derives a portion of its operating margin through energy revenues under the PG&E PPA. Energy revenues are dependent on PG&E's short-run avoided costs ("SRAC"), which is generally defined as the cost of electricity that a utility avoids incurring by purchasing the power from an independent power producer versus constructing and operating additional generating resources on its own. PG&E's SRAC is determined by the CPUC in conjunction with input from independent power producers, investor owned utilities and consumer groups through the state utility regulatory process. SRAC has been, and continues to be, a highly contested issue resulting in numerous CPUC proceedings and litigation.

In April 2009, California's Market Reform and Technology Update energy market ("MRTU") commenced operation. The MRTU is expected to provide a robustly traded day-ahead market for energy that reflects the avoided marginal energy costs of California's utilities.

SRAC was based on an administratively determined formula until August 2009, when the CPUC implemented a new SRAC methodology called the market index formula ("MIF"), which includes both a market-based component and an administratively determined component. Ultimately, the CPUC is moving toward a 100% market-based SRAC. Upon the determination by the CPUC that the MRTU is functioning properly, MIF will no longer include the administratively determined component, which is expected to be lower than the original MIF pricing and create larger differences between peak and off-peak prices. Such a determination has not been made by the CPUC.

Badger has been a party to settlement negotiations among other QF facilities, California's major investor-owned utilities, and numerous consumer and independent power producer groups on a new energy pricing formula and possible extensions of firm capacity payments for projects with existing contracts that will resolve many outstanding issues between the parties. Many of the SRAC and MIF related CPUC proceedings and litigation were held in abeyance pending the outcome of the settlement negotiations. In December 2010, a settlement was approved by the CPUC, however several parties have filed requests for rehearing. The settlement is expected to be finalized and implemented in 2011.

Badger Creek's PPA and steam sales agreements expire in April 2011. To the extent the agreements cannot be extended or replaced on economical terms, the financial viability of the project would be jeopardized.

**Koma Kulshan project**

*General description*

The Koma Kulshan project is a 13.3 MW run-of-the-river hydroelectric generation facility located on the slopes of Mount Baker, approximately 80 miles north of Seattle, Washington, which began commercial operation in 1990 as a QF. The Koma Kulshan project is owned by Koma Kulshan Associates, a California limited partnership in which we own a 49.75% economic interest, Mt. Baker Corporation owns a 0.25% economic interest and Covanta Energy Corporation ("Covanta") owns the remaining 50%. The Koma Kulshan project was issued a 50-year hydro license from the FERC which expires in 2037. The project and its electrical output is sold to Puget Sound Energy, Inc. under a PPA expiring in 2037.

Our and Mt. Baker Corporation's interests in the project are held through Concrete Hydro Partners, L.P. ("Concrete"). Under the Concrete partnership agreement, Mt. Baker Corporation is entitled to reimbursement of certain deferred costs associated with the original development of the project from a portion of the distributions from the project. The full repayment of these deferred costs occurred in 2010, following which distributions are projected to be made ratably to us and Mt. Baker Corporation.

*Power purchase agreement*

Energy generated by the Koma Kulshan project is sold to Puget Sound Energy pursuant to a long-term PPA expiring in 2037. Power is sold at a per kilowatt hour rate that is adjusted annually. The term of the PPA is co-terminous with the FERC license. Puget Sound Energy has the right to renew the PPA for a term equivalent to the term of any subsequent license or annual license granted by the FERC for the project.

*Operations & maintenance*

Covanta performs the operations and maintenance of the facility pursuant to an operations and maintenance agreement which expires December 31, 2010. In addition to being reimbursed for actual costs incurred, Covanta receives an annual fee adjusted for inflation.

**Delta-Person project**

*General description*

The Delta-Person project, a 132 MW natural gas-fired peaking facility located near Albuquerque, New Mexico, is an exempt wholesale generator that commenced commercial operation in 2000. We own a 40% interest in Delta-Person and affiliates of Olympus Power, LLC, John Hancock Mutual Life Insurance Company, and ArcLight Capital Partners, LLC own the remaining interests. The Delta-Person project is situated on PNM's (formerly Public Service of New Mexico) retired Delta Generating Station site under a lease agreement which is co-terminous with the project's PPA. The project operates as a peaking facility, which means that it is called upon to generate electricity only during unusually high periods of demand. The Delta-Person project sells all of its electrical output to PNM under a long-term PPA that expires in 2020.

The Delta-Person project was financed with two non-recourse term loans: (i) Tranche A due March 31, 2017; and (ii) Tranche B due March 31, 2019, both of which amortize over their remaining terms. Our share of the total debt outstanding at the Delta-Person project as of December 31, 2010 was $10.5 million. See "Project-level debt" on page 72 of this Form 10-K for additional details.

*Power purchase agreement*

Electrical power generated by the Delta-Person project is purchased by PNM under a PPA that will expire in 2020. PNM has the unilateral right to extend the PPA for five years by giving written notice of such extension no later than two years prior to the end of the original term of the PPA. Subject to adjustments provided for in the PPA, PNM will purchase and accept the entire output of the project when PNM calls upon the capacity. Payments consist of: (i) the energy purchase price multiplied by the kilowatt hours delivered; (ii) the capacity purchase price multiplied by the dependable capacity; (iii) the project's cost of purchasing electric service from PNM for the operations and maintenance of the facility; and (iv) any other applicable charges. In order to earn full capacity payments, the project must maintain availability of at least 97%, which the project has historically achieved.

*Fuel supply arrangements*

The project purchases fuel from PNM Gas Services, a division of PNM, with fuel costs passed through to PNM under the PPA. The project has access to an interruptible gas supply and transportation like other standard industrial customers on PNM Gas Services' system.

*Operations & maintenance*

As a simple cycle peaking facility, the project operations do not require extensive staffing and technical resources. Olympus Power provides asset management services, which include operational and contractual oversight of the facility, budget setting and environmental compliance. The project has a contractual services agreement in place with GE that covers major maintenance expenses. The costs incurred under this agreement are passed through PNM under the PPA.

*Factors influencing project results*

The Delta-Person project derives a significant portion of its operating margin through capacity payments under the PPA with PNM. The capacity payment is based on two components which adjust annually with changes in inflation and interest rates. The capacity payment may be reduced in any monthif the project's average availability falls below 97% during that month. The project has rarely experienced such adjustment. Energy payments are based on a variable operations and maintenance component, a fuel component and an availability incentive. The fuel component is based on the actual price the project pays for fuel and a contract heat rate. The contractually guaranteed heat rate is slightly higher than the project's average operating heat rate which generates additional energy margin when the project operates. PNM will normally choose to purchase power from higher efficiency plants during periods of reduced demand. Reduced overall economic activity and related lower demand for electricity in the past two years has resulted in lower dispatch of Delta-Person by PNM.

**Idaho Wind project**

*General description*

The Idaho Wind project is a 183 MW wind power project comprised of 11 wind farms located near Twin Falls, Idaho. Construction of the projects began in June 2010 and began commercial operation in 2011 as QFs. The Idaho Wind project is owned by Idaho Wind Partners 1, LLC ("Idaho Wind"), a Delaware limited partnership in which we own a 27.6% partnership interest. Our equity interest in the project was purchased in July 2010. The other owners are affiliates of GE Energy Financial Services, Reunion Power, and Exergy Development Group, the original project developer. Electricity is sold to Idaho Power Company under eleven PPAs expiring in 2030. Idaho Wind leases the land on which the wind projects are located from various land owners under long-term leases that expire in 2040 or after.

The project was financed by Bank of Tokyo-Mitsubishi and a consortium of other lenders. On October 8, 2010, Idaho Wind closed a $221.7 million project-level credit facility. The facility is composed of two tranches, which include a $138.5 million construction loan that will convert to a 17-year term loan following commercial operation, and an $83.2 million cash grant facility which will be repaid with federal stimulus grant proceeds after completion of construction. On January 20, 2011, Idaho Wind had a second closing for an additional $19.0 million to increase the construction loan to $157.5 million. The construction loan is expected to convert to a term loan in the first quarter of 2011 and will amortize over its life and will mature in 2027.

The remaining costs of the project of approximately $200 million were funded with a combination of equity from the owners and member loans from affiliates of Atlantic Power and GE Energy Financial Services. As of December 31, 2010, our share of total debt outstanding for Idaho Wind was $48.4 million, and our share of the member loans was $22.8 million. Member loans will be paid down with a combination of excess proceeds from the federal stimulus cash grant after repaying the cash grant facility, funds from a third closing for additional debt, and project cash flow. The federal stimulus grant is expected in the second quarter of 2011 and a third closing is expected by the end of the year. As of March 18, 2011, $5.1 million of the loan has been repaid. See "Project-level debt" on page 72 on this Form 10-K for additional details.

*Power Purchase Agreements*

Idaho Wind sells all of its output to Idaho Power Company under 11 separate 20-year power purchase agreements that expire in 2030. Under the terms of the agreements, Idaho Power purchases all of the electricity at fixed prices, although the pricing structure under the agreements differs. For eight of the eleven PPAs, the fixed price paid for electricity escalates annually through the life of the agreement. For the remaining three agreements, the price paid for electricity remains unchanged for the term of the agreements.

In the event the wind farms do not maintain a minimum level of availability or underperform relative to monthly nominations under the PPA, the price paid for electricity would be reduced. The Credit support for the PPAs consists of approximately $20.0 million of letters of credit issued by the project lenders.

*Operations and Maintenance*

The Idaho Wind project consists of 122 GE 1.5 MW wind turbines purchased under a turbine supply agreement with GE. The turbine supply agreement includes a two-year warranty for removal and replacement of parts.

Idaho Wind also has an 8-year operations support agreement in place with GE. The operations support agreement provides for ongoing monitoring of the performance of the wind turbine generators as well as planned and unplanned maintenance. The operations support agreement includes a warranty on wind turbine availability. Idaho Wind also has a balance of plant maintenance contract with Caribou Construction, which provides service of the substations and other maintenance not associated with the wind turbines.

Idaho Wind is operated and maintained on a day-to-day basis by an affiliate of Reunion Power pursuant to a 7-year management service agreement.

*Factors influencing project results*

Wind is used to generate electricity utilizing wind turbines to transform the kinetic energy of wind into electrical energy. The Idaho Wind project energy forecast and revenue projections are based on detailed wind studies. Wind speed data were collected on site for over five years then analyzed using complex computer modeling by third party consultants. If there is insufficient wind, the underlying financial performance could be materially adversely affected.

Idaho Wind is subject to operational risks that could have an adverse effect on financial performance. The risks associated with the project are partially mitigated by the operations support agreement with the original equipment supplier.

**Piedmont Green Power project**

*General Description*

Piedmont is a 53.5 MW biomass-fired electric generating facility under construction in Barnesville, Georgia approximately 60 miles southeast of Atlanta. It was developed by our 60% owned subsidiary Rollcast Energy, Inc. The project will sell 100% of its output to Georgia Power Company under a 20-year PPA. Piedmont has executed two long-term biomass fuel supply contracts with pricing terms that largely track the energy payment under the PPA. Zachry Industrial ("ZHI") is constructing the facility under a turn-key engineering procurement and construction contract. The project is being constructed on a 49.8 acre site and will consist of a wood fuel handling system, bubbling fluidized bed boiler technology and a steam turbine generator. Total project costs of approximately $207.4 million were financed in part with an $82.0 million construction loan which will convert to a term loan upon commercial operation, a $51.0 million bridge loan and approximately $75.0 million of equity to be contributed by Atlantic Power. The bridge loan will be repaid from the proceeds of a federal stimulus grant which is expected to be received two months after achieving commercial operation. Notice to proceed was authorized in October 2010 and commercial operation of the project is expected in late 2012.

*Power purchase agreement*

The Project has a twenty-year PPA with Georgia Power for the purchase of capacity and energy expiring in September 2032. The capacity payment rate is seasonally weighted with higher payments in the summer. The capacity payment will be based on the output of the project as demonstrated in performance tests that may be administered annually, if requested by Georgia Power. The capacity payment will be adjusted seasonally based on seasonal plant availability. If contract availability is less than 96% (excluding scheduled maintenance outages, and outages caused by force majeure events) the capacity payment will be reduced by 1.5% for each 1% reduction in availability below 96%. If contract availability is below 60%, no capacity payment will be made. Over 55% of the project's revenue stream consists of capacity payments.

The energy payment is based on several factors that reflect the cost of acquiring biomass fuel in Georgia. Similar factors are reflected in the pricing of biomass under Piedmont's fuel supply contracts.

*Interconnection Agreement*

The project has entered into a 10-year interconnection agreement with Southern Company Services. The agreement is subject to automatic renewal for one year periods thereafter. This agreement will provide for the interconnection of the project with the transmission system of Southern Company Services.

*Fuel Supply Agreements*

The project's primary source of biomass fuel is urban wood waste provided through long-term supply contracts with two local suppliers. Each contract has minimum take obligations which in aggregate represent 84.0% of Piedmont's total annual biomass fuel requirements. When biomass prices in the spot market are lower than Piedmont's contracted supply, the project will have the ability to take the minimum contract amounts and obtain up to approximately 16% of its annual fuel requirements from the spot biomass market.

The two fuel supply agreements have terms of 10 and 20 years and each has automatic extension provisions. Pricing under both contracts escalates based on periodic changes in a basket of widely available indices reflecting the cost of obtaining, processing and delivery of urban wood waste biomass. Several biomass fuel studies were prepared in conjunction with the development and financing of the project, which indicated an available and sustainable biomass fuel supply exceeding several times the project's fuel requirements.

*Operations & Management*

Piedmont has executed a five-year operations and management agreement with Delta Power Services ("DPS"). DPS will be paid its actual direct operating costs plus an annual fee. A portion of the annual fee consists of an operating bonus which is earned by success in five performance metrics based on safety, environmental/emissions compliance, availability, fuel budget and operating budget.

Piedmont has executed a management services agreement with Rollcast for the provision of administrative services and asset management.

*Factors influencing project results*

The Piedmont project is currently under construction and is expected to achieve commercial operation in late 2012. The operation and financial performance of the project may be negatively impacted as a result of circumstances which prevent its timely completion, cause construction costs to exceed the level budgeted, or result in operating performance standards or permit conditions not being met. The terms of the engineering, construction and procurement agreement with ZHI provide for the project to be paid significant liquidated damages in the event certain construction milestones or performance testing requirements are not met. These liquidated damages provisions are structured to mitigate the negative impact associated with construction delays or performance shortfalls. Cost overruns are also mitigated by construction contingencies built into the construction budget.

The Piedmont project will derive a significant portion of its revenue from capacity payments under the Georgia Power PPA. In the event the project does not maintain a high availability factor, these revenues would be adversely impacted.

The project's results could be reduced due to a divergence in the energy payment under the PPA and the price that Piedmont is paying for fuel, resulting in the project under recovering its fuel expenses. The energy payment under the PPA is based on indices similar to the pricing components in the fuel supply agreements.

Piedmont is dependent on two fuel suppliers for nearly all of its fuel requirements. In the event either supplier was unable to meet its contractual obligations, the project would need to seek alternative sources for its biomass fuel supply. The project is located in an area of central Georgia, where there are significant and sustainable biomass fuel resources, including urban wood waste, forest residues, and mill residues that are capable of meeting several times the annual fuel requirements of Piedmont.

**Cadillac Project**

*General Description*

The Cadillac project is a 39.6 MW biomass power generation facility located in north central Michigan approximately 200 miles north of Detroit. The project achieved commercial operation in July 1993 and is a QF. In December 2010, Atlantic Power acquired a 100% indirect ownership in Cadillac Renewable Energy, LLC, the owner of the project, from Arclight Energy Partners Fund II and Olympus Power, LLC.

The project is located in Cadillac, Michigan. Cadillac sells up to 34 MW of its capacity and energy under a PPA with Consumers Energy Company ("Consumers"), which expires in 2028, with the remaining output sold in the spot market. The project utilizes approximately 325,000 tons of biomass fuel per year, predominantly derived from the forest products industry in the region. The project is operated by DPS under an operation and maintenance agreement.

Cadillac has non-recourse debt outstanding of $41.1 million at December 31, 2010, which fully amortizes through 2025. In addition there are notes in the aggregate amount of approximately $1.4 million with Beaver Michigan Associates, LP, a party involved in the early development of the project, due April 15, 2012. We have provided letters of credit of $3.9 million to support the PPA with Consumers.

*Power purchase agreement*

Energy and capacity is sold to Consumers pursuant to a PPA that expires on August 1, 2028. Revenues from the sale of electricity consist of a fixed capacity payment and an energy payment. Capacity payments are subject to the project maintaining an availability factor of at least 95% during on-peak hours, on a 12-month calendar year basis. Cadillac is subject to reductions in its capacity payment should it not achieve the 95% availability factor. The project generally has achieved the 95% availability factor continuously since commercial operations began in 1993. Energy payments are comprised of a fixed energy payment and a variable energy payment. The fixed energy payment, paid whether or not the project generates energy, is indexed to several factors related to costs associated with Consumers' costs of generation at established base load coal-fired generating facilities during the most recent calendar year. The variable energy payment is based on the amount of energy delivered to Consumers, the average operating costs of certain Consumers base plants during the most recent 12-month period, and the weighted average cost per kWh of coal burned in certain Consumers base plants for the most recent 12-month period.

In 2007, Cadillac entered into a Reduced Dispatch Agreement ("RDA") with Consumers under which the project shares in the benefit when Consumers reduces the dispatch level of the project to a specified minimum during periods in which it can purchase replacement power in the wholesale market at a price that is less than Cadillac's variable cost of production. Cadillac receives 80% of the net benefits associated with the purchase of displacement power and Consumers receive the remaining 20%. The term of the RDA runs through 2016.

The project can generate up to 4 MW of power above the maximum 34 MW that is sold to Consumers under the PPA. The excess power is sold into the Michigan Independent System Operator ("ISO"). Cadillac bids the excess power into the Michigan ISO day ahead market when prices exceed its marginal cost of production, plus a minimum gross margin.

The facility is a qualifying facility under the Michigan Renewable Portfolio Standard ("MRPS") and generates approximately 51,800 MWh of Renewable Energy Credits ("RECs") annually. The RECs are sold into the secondary market.

*Fuel Supply arrangements*

The project purchases fuel under numerous short-term supply contracts from approximately 30 local suppliers. The biomass fuel consists of approximately 85% forestry residue. The balance is comprised of sawdust, recycled wood and grindings. The project has annual fuel requirements of approximately 360,000 tons per year, most of which is delivered from within a 75 mile radius of the project.

*Operations and maintenance*

The project has a long-term operations and management agreement with DPS that is co-terminous with the PPA in July 2028. Following the acquisition of the project by Atlantic Power, DPS has retained key members of the project's management team, many of whom had been with the project since it began commercial operation 17 years ago.

*Factors influencing project results*

As a qualifying facility under the MRPS, the project is reimbursed for a portion of its operating expenses, including fuel, as provided for by Michigan House Bill 5524. The Bill, which does not require annual authorization or appropriation, provides for the reimbursement to qualified facilities of variable operating costs (including fuel) incurred in the production of renewable energy in excess of any variable energy payment received under a PPA. The project receives a monthly payment from Consumers for 80% of the reimbursement. The remaining 20% is withheld for an annual reconciliation. The benefits of House Bill 5524 are limited to seven qualifying facilities in Michigan and payments to the qualifying facilities are capped at $1 million per month. Cadillac's share of the total payments is based on the project's pro rata share of aggregate generation among the six other qualifying facilities. In 2010 the project received $1.5 million under the Bill. Variable costs of operation, including fuel costs in excess of the variable energy payment under the Consumers PPA are eligible for reimbursement.

A proceeding is currently underway before the Michigan Public Service Commission to, among other things, finalize the reconciliation of reimbursement payments by Consumers for the period of October 2008 through December 2009. A final order from the Michigan Public Service Commission is expected in the second half of 2011.

**Biomass development projects**

Biomass-derived power is a well-established, conventional technology. In biomass power plants, the fuel is burned in a boiler to create steam that turns a turbine to generate electricity. In general, biomass power plants are designed to be operated as baseload units. While biomass encompasses a broad range of potential fuels, our activities are focused on "wood-residue" biomass. This feedstock includes virgin wood (from forests, wood processing facilities, etc.), agricultural residues, industrial and commercial wood waste, etc. These facilities are eligible for renewable energy credits and may also qualify for certain federal tax benefits, depending on their construction schedule. We are pursuing several biomass projects with partners who bring specific skills to their development, as more fully described below.

**Rollcast Energy, Inc.**

Rollcast Energy, Inc. (“Rollcast”) develops, owns and operates renewable power plants that use wood or biomass fuel. Rollcast, based in Charlotte, North Carolina, has four 50 MW biomass power plants in various stages of development in the southeastern U.S. In March 2009, we acquired a 40% equity interest in Rollcast for $3.0 million. In March 2010, we acquired an additional 15% interest for $1.2 million and in April 2010, we invested an additional $0.8 million to bring our total ownership interest to 60%. The terms of our investment in Rollcast provide us the option, but not the obligation, to invest directly in biomass power plants under development by Rollcast. Two of the development projects have obtained 20-year PPAs with terms that allow for the pass-through of fuel costs to the utility customer. In October 2010, financing closed on one of our Rollcast development projects (Piedmont) and is currently under construction. We have currently invested $68.5 million and expect to invest up to a total of $75.0 million in the Piedmont project, representing substantially all of the equity interests in the project.

**Onondaga Renewables, LLC**

Onondaga Renewables, LLC is a 50/50 joint venture between us and Catalyst Renewables LLC formed in December 2008 to repower our decommissioned 91 MW gas-fired cogeneration facility located in Geddes, New York. Utilizing locally acquired biomass fuel, the proposed facility is expected to have a capacity of approximately 45 MW. Onondaga is currently in the process of obtaining a PPA for the full output of the facility. Our share of development expenditures to date is approximately $1.2 million.

**ASSET MANAGEMENT**

Our asset management strategy is to ensure that our projects receive appropriate preventative maintenance and capital expenditures if required to provide for their safety, efficiency, availability and longevity. We also proactively look for opportunities to optimize power, fuel supply and other agreements to deliver strong and predictable financial performance. For operations and maintenance services, we partner with recognized leaders in the independent power business. Most of our projects are managed by Caithness; Power Plant Management Services; and, in the case of Path 15, Western, a U.S. Federal power agency. On a case-by-case basis, Caithness, Power Plant Management Services, and Western may provide: (i) day-to-day project-level management, such as operations and maintenance and asset management activities; (ii) partnership level management tasks, such as insurance renewals, annual budgets; and (iii) partnership level management, such as acting as limited partner. In some cases these project managers or the project partnerships may subcontract with other firms experienced in project operations, such as GE, to provide for day-to-day plant operations. In addition, employees of Atlantic Power Corporation with significant experience managing similar assets are involved in all significant decisions with the objective of proactively identifying value-creating opportunities such as contract renewals or restructurings, asset-level refinancings, add-on acquisitions, divestitures and attend partnership meetings and calls.

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

Power Plant Management Services is a management services company focused on providing senior level energy industry expertise to the independent power market. Founded in 2006, Power Plant Management provides management services to a large portfolio of solid fuel and gas-fired generating stations. Previously, Cogentrix provided these services to our Selkirk and Chambers facilities. In August 2010, Energy Investors Funds, which holds the controlling interest in a portfolio of 13 power generating projects (of which Chambers and Selkirk are a part), terminated its management services agreement with Cogentrix and entered into a new agreement with Power Plant Management Services.

Western markets, transmits and delivers hydroelectric power and related services within a 15-state region of the central and western United States. Western is one of four power marketing administrations within the U.S. Department of Energy whose role is to market and transmit electricity from multi-use water projects. Western's transmission system carries electricity from 57 power plants operated by the Bureau of Reclamation, U.S. Army Corps of Engineers and the International Boundary and Water Commission. Together, these plants have an operating capacity of approximately 8,785 MW. Western owns and maintains the Path 15 transmission line.

## INDUSTRY REGULATION

### Overview

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

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

### Regulation—generating projects

Ten of our power generating projects are qualifying facilities under PURPA and related FERC regulations. The Delta-Person and Pasco projects are not QFs but are both exempt wholesale generators under the Public Utility Holding Company Act of 2005, as amended ("PUHCA"). The generating projects with QF status and which are currently party to a power purchase agreement with a utility or have been granted authority to charge market-based rates are exempt from FERC rate-making authority. The FERC has granted seven of the projects the authority to charge market-based rates based primarily on a finding that the projects lack market power. These projects are thus not subject to FERC rate-making. The generating projects are exempt from regulation under PUHCA and the projects with QF status are also exempt from state regulation respecting the rates of electric utilities and the financial or organizational regulation of electric utilities.

A QF falls into one or both of two primary classes, both of which would facilitate more efficient use of fossil fuels to generate electricity than typical utility plants. The first class of QFs includes energy producers that generate power using renewable energy sources such as wind, solar, geothermal, hydro, biomass or waste fuels. The second class of QFs includes cogeneration facilities, which must meet specific fossil fuel efficiency requirements by producing both electricity and steam versus electricity only. With the exception of QFs, generation, transmission and distribution of electricity remained largely owned by vertically integrated electric utilities until the enactment of the Energy Policy Act of 1992 (the "EP Act of 1992") and subsequent orders in 1996, along with electric industry restructuring initiated at the state level. Among other things, the EP Act of 1992 enhanced the FERC's power to order open access to power transmission systems, contributing to significant growth in the independent power generation industry.

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

All of our projects are subject to reliability standards developed and enforced by the North American Electric Reliability Corporation ("NERC"). NERC is a self-regulatory non-governmental organization which has statutory responsibility to regulate bulk power system users, generation and transmission owners and operators through the adoption and enforcement of standards for fair, ethical and efficient practices.

In March 2007, the FERC issued an order approving mandatory reliability standards proposed by NERC in response to the August 2003 northeastern U.S. blackouts. As a result, users, owners and operators of the bulk power system can be penalized significantly for failing to comply with the FERC-approved reliability standards. We have designated our Senior Director for Asset Management as our FERC Compliance Officer responsible for meeting the FERC and NERC requirements and an outside law firm specializing in this area advises us on FERC and NERC compliance, including annual compliance training for relevant employees.

**Regulation—transmission project**

The revenues received by the Path 15 project are regulated by the FERC through a rate review process every three years that sets an annual revenue requirement. Under terms of the initial rate case settlement, the project must go through the FERC review every three years.

On February 18, 2011, the project filed its revenue requirement with the FERC for the period of 2011 through 2013. Under the project's prior rate case proceeding at the FERC that set the project's revenue requirement for the period of 2008 through 2010, the Path 15 project was required to file its subsequent rate case no later than February 18, 2011.

**Carbon emissions**

In the United States, government policy addressing carbon emissions had gained momentum over the last two years, but has slowed at the federal level more recently. Beginning in 2009, the Regional Greenhouse Gas Initiative was established in ten Northeast and Mid-Atlantic states as the first cap-and-trade program in the United States for $CO_2$ emissions. These states have varied implementation plans and schedules. The two states where we have project interests, New York and New Jersey, also provide cost mitigation for independent power projects with certain types of power contracts. Other states and regions in the United Sates are developing similar regulations and it is expected that federal climate legislation will be established in the future.

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

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

## COMPETITION

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

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

We compete for acquisition opportunities with numerous private equity funds, infrastructure funds, Canadian and U.S. independent power firms, utility genco subsidiaries and other strategic and financial players. Our competitive advantages include our competitive access to capital, experienced management team, diversified projects, strong customer base, leading third-party operators and stability of project cash flow. We have similar strength in asset management and optimization.

## EMPLOYEES

As of March 18, 2011, we had 13 employees. None of our employees is represented by any collective bargaining unit or a party to any collective bargaining agreement.

## ITEM 1A. RISK FACTORS

### Risks Related to Our Business and Our Projects

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

Power generated by our projects, in most cases, is sold under PPAs that expire at various times. For example, the PPA at our Badger Creek project expires in 2011 and represent 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 8 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, our utility customer has the right to sell a portion of the plant's output into the spot power market if it is economical to do so and the Chambers project shares in the profits from these sales. In addition, during periods of low spot electricity prices the 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 forecast 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. We have executed a hedging program to substantially mitigate this risk through 2013.

The amount of energy generated at the projects is dependent upon the availability of natural gas, coal, oil or biomass. The long-term availability of such resources could change in the future.

***Generation from windpower projects may be less than anticipated***

We now own a windpower project, which is exposed to the risk of its wind resource having unfavorable characteristics, which in conjunction with the wind resource study, could result in unfavorable financial impacts to its expected 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 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.

***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 the cash flow, financial position and results of operations of us and Path 15, and could adversely affect our cash available for dividends.

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

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

***Our projects are subject to significant environmental and other regulations***

Our projects are subject to numerous and significant federal, state and local laws, including statutes, regulations, by-laws, guidelines, policies, directives and other requirements governing or relating to, among other things: air emissions; discharges into water; ash disposal; the storage, handling, use, transportation and distribution of dangerous goods and hazardous, residual and other regulated materials, such as chemicals; the prevention of releases of hazardous materials into the environment; the prevention, presence and remediation of hazardous materials in soil and groundwater, both on and off site; land use and zoning matters; and workers' health and safety matters. As such, the operation of our projects carries an inherent risk of environmental, health and safety liabilities (including potential civil actions, compliance or remediation orders, fines and other penalties), and may result in the projects being involved from time to time in administrative and judicial proceedings relating to such matters.

The Clean Air Act and related regulations and programs of the Environmental Protection Agency extensively regulate the air emissions of sulfur dioxide, nitrogen oxides, mercury and other compounds emitted by power plants. Environmental laws and regulations have generally become more stringent over time, and this trend may continue. In particular, the Environmental Protection Agency has 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 and 2010 respectively, and has also promulgated regulations requiring reductions in mercury emissions from coal-fired electric generating units, beginning in 2010 with more substantial reductions 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 July 6, 2010, the Environmental Protection Agency proposed to replace CAIR with the Interstate Transport Rule which would require 31 states and the District of Columbia to curb emissions of sulfur dioxide and nitrogen oxides from power plants through more aggressive state-by-state emissions budgets for nitrogen oxides and sulfur dioxide. The Environmental Protection Agency expects to finalize the interstate transport rule in late spring of 2011. The first phase of compliance would be required by early 2012 and the second phase by early 2014. Compliance with the proposed 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 2014. Meeting these new standards at our coal-fired facility may have a material adverse impact on our business, operations or financial condition.

The Resource Conservation and Recovery Act has historically exempted fossil fuel combustion wastes from hazardous waste regulation. However, in June 2010 the Environmental Protection Agency proposed two alternative sets of regulations governing coal ash. One set of proposed regulations would designate coal ash as "special waste" and bring ash impoundments at coal-fired power plants under federal regulations governing hazardous solid waste under Subtitle C of the Resource Conservation and Recovery Act. Another set of proposed regulations would regulate coal ash as a non-hazardous solid waste. If the Environmental Protection Agency determines to regulate coal ash as a hazardous waste, our 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 expenditures or the purchase of allowances under any or all of these programs to keep the projects compliant with environmental laws and regulations. The projects' PPAs do not allow for the pass through of emissions allowance or emission reduction capital expenditure costs, with the exception of Pasco. If it is not economical to make those expenditures it may be necessary to retire or mothball facilities, or restrict or modify our operations to comply with more stringent standards.

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

***Our projects are subject to regulation of $CO_2$ 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 now a tradable commodity, currently averaging in the $1.86/ton range. The State of Florida has conducted stakeholder meetings as part of the process of developing greenhouse gas emissions regulations, the most recent of which was in January 2009. Discussions indicate favoring a program similar to that of the Regional Greenhouse Gas Initiative.

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

In 2006, the State of California passed legislation initiating two programs to control/reduce the creation of greenhouse gases. The two laws, more commonly known as AB 32 and SB 1368, are currently in the regulatory rulemaking phase which will involve public comment and negotiations over specific provisions. Development towards the implementation of these programs continues.

Under AB 32 (the California Global Warming Act of 2006) the California Air Resources Board ("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.

Since the 2010 elections in California, 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.

SB 1368 added the requirement that the California Energy Commission, in consultation with the California Public Utilities Commission (the "CPUC") and the CARB establish greenhouse gas emission performance standards and implement regulations for power purchase agreements that exceed five years entered into prospectively by publicly-owned electric utilities. The legislation directs the California Energy Commission to establish the performance standard as one not exceeding the rate of greenhouse gas emitted per megawatt-hour associated with combined-cycle, gas turbine baseload generation, such as our Badger Creek project. Provisions are under consideration in the rulemaking process to allow facilities that have higher $CO_2$ emissions to be able to negotiate PPAs for up to a five-year period or sell power to entities not subject to SB 1368.

In addition to the regional initiatives, legislation for the 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, to take effect in 2011, which requires large industrial facilities, including power plants, to obtain permits to emit, and to use best available control technology to curb emissions of, greenhouse gases.

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

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

The power generation industry is characterized by intense competition, and our projects encounter competition from utilities, industrial companies and other independent power producers, in particular with respect to uncontracted output. In recent years, there has been increasing competition among generators for power sales agreements, and this has contributed to a reduction in electricity prices in certain markets where supply has surpassed demand plus appropriate reserve margins. 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 March 18, 2011, we had no borrowings outstanding under our revolving credit facility, $212.9 million of outstanding convertible debentures, and $251.8 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. 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.

Our failure to refinance or repay any indebtedness when due could constitute a default under such indebtedness. Under such circumstances, it is expected that dividends to our shareholders would not be permitted until such indebtedness was refinanced or repaid and we may be required to sell assets or take other actions, including the initiation of bankruptcy proceedings or the commencement of an out-of-court debt restructuring.

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

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

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

We and the projects may use derivative instruments, including futures, forwards, options and swaps, to manage commodity and financial market risks. In the future, the project operators could recognize financial losses on these arrangements as a result of volatility in the market values of the underlying commodities or if a counterparty fails to perform under a contract. If actively quoted market prices and pricing information from external sources are not available, the valuation of these contracts would involve judgment or use of estimates. As a result, changes in the underlying assumptions or use of alternative valuation methods could affect the reported fair value of these contracts.

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

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

***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.

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 March 18, 2011, our consolidated long-term debt and our share of the debt of our unconsolidated affiliates represented approximately 50.3% of our total capitalization, comprised of debt and balance sheet equity.

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

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

***Future issuances of our common shares could result in dilution***

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

***Investment eligibility***

There can be no assurance that our common shares will continue to be qualified investments under relevant Canadian tax laws for trusts governed by registered retirement savings plans, registered retirement income funds, deferred profit sharing plans, registered education savings plans, registered disability savings plans and tax-free savings accounts.

***We are subject to Canadian tax***

As a Canadian corporation, we are generally subject to Canadian federal, provincial and other taxes, and dividends paid by us are generally subject to Canadian withholding tax if paid to a shareholder that is not a resident of Canada. We completed our initial public offering on the TSX in November 2004. At the time of the initial public offering, our public security was an IPS. Each IPS was comprised of one common share and Cdn$5.767 principal value of 11% subordinated notes due 2016. In the fourth quarter of 2009, we converted to a traditional common share company through a shareholder approved plan of arrangement in which each IPS was exchanged for one of our new common shares. Our new common shares were listed and posted for trading on the TSX commencing on December 2, 2009 and trade under the symbol "ATP," and the former IPSs, which traded under the symbol "ATP.UN," were delisted at that time. In connection with our conversion from an IPS structure to a traditional common share structure and the related reorganization of our organizational structure, we received a note from our primary U.S. holding company (the "Intercompany Note"). We are required to include in computing our taxable income interest on the Intercompany Note. We expect that our existing tax attributes initially will be available to offset this income inclusion such that it will not result in an immediate material increase to our liability for Canadian taxes. However, once we fully utilize our existing tax attributes (or if, for any reason, these attributes were not available to us), our Canadian tax liability would materially increase. Although we intend to explore potential opportunities in the future to preserve the tax efficiency of our structure, no assurances can be given that our Canadian tax liability will not materially increase at that time.

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

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

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

Under our prior IPS structure, we treated the subordinated notes as debt for U.S. federal income tax purposes. Accordingly, we deducted the interest payments on the subordinated notes and reduced our net taxable income treated as "effectively connected income" for U.S. federal income tax purposes. Under our current structure, our subsidiaries that are incorporated in the United States are subject to U.S. federal income tax on their income at regular corporate rates (currently as high as 35%, plus state and local taxes), and one of our U.S. holding companies will claim interest deductions with respect to the Intercompany Note in computing its income for U.S. federal income tax purposes. To the extent this interest expense under either the subordinated notes or the Intercompany Note is disallowed or is otherwise not deductible, the U.S. federal income tax liability of our U.S. holding company will increase, which could materially affect the after-tax cash available to distribute to us. While we received advice from our U.S. tax counsel, based on certain representations by us and our U.S. holding company and determinations made by our independent advisors, as applicable, that the subordinated notes and the Intercompany Note should be treated as debt for U.S. federal income tax purposes, it is possible that the Internal Revenue Service ("IRS") could successfully challenge those positions and assert that subordinated notes or the Intercompany Note should be treated as equity rather than debt for U.S. federal income tax purposes. In this case, the otherwise deductible interest on the subordinated notes or the Intercompany Note would be treated as non-deductible distributions and, in the case of the Intercompany Note, would be subject to U.S. withholding tax to the extent our U.S. holding company had current or accumulated earnings and profits. The determination of whether the subordinated notes and the U.S. holding company's indebtedness to us is debt or equity for U.S. federal income tax purposes is based on an analysis of the facts and circumstances. There is no clear statutory definition of debt for U.S. federal income tax purposes, and its characterization is governed by principles developed in case law, which analyzes numerous factors that are intended to identify the nature of the purported creditor's interest in the borrower. Furthermore, not all courts have applied this analysis in the same manner, and some courts have placed more emphasis on certain factors than other courts have. To the extent it were ultimately determined that our interest expense on either the subordinated notes or the Intercompany Note were disallowed, our U.S. federal income tax liability for the applicable open tax years would materially increase, which could materially affect the after-tax cash available to us to distribute. Alternatively, the IRS could argue that the interest on the subordinated notes or the Intercompany Note exceeded or exceeds an arm's length rate, in which case only the portion of the interest expense that does not exceed an arm's length rate may be deductible and, in the case of the Intercompany Note, the remainder would be subject to U.S. withholding tax to the extent our U.S. holding company had current or accumulated earnings and profits. We have received advice from independent advisors that the interest rate on the subordinated notes and the Intercompany Note was and is, as applicable, commercially reasonable in the circumstances, but the advice is not binding on the IRS. Furthermore, our U.S. holding company's deductions attributable to the interest expense on the Intercompany Note may be limited by the amount by which its net interest expense (the interest paid by our U.S. holding company on all debt, including the Intercompany Note, less its interest income) exceeds 50% of its adjusted taxable income (generally, U.S. federal taxable income before net interest expense, net operating loss carryovers, depreciation and amortization). Any disallowed interest expense may currently be carried forward to future years. Moreover, proposed legislation has been introduced, though not enacted, several times in recent years that would further limit the 50% of adjusted taxable income cap described above to 25% of adjusted taxable income, although recent proposals in the Fiscal Year Budget for 2010 would only apply the revised rules to certain foreign corporations that were expatriated. Furthermore, if our U.S. holding company does not make regular interest payments as required under the Intercompany Note, other limitations on the deductibility of interest under U.S. federal income tax laws could apply to defer and/or eliminate all or a portion of the interest deduction that our U.S. holding company would otherwise be entitled to with respect to the Intercompany Note.

*Passive foreign investment company treatment*

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

## ITEM 1B. UNRESOLVED STAFF COMMENTS

None

## ITEM 2. PROPERTIES

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

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

## ITEM 3. LEGAL PROCEEDINGS

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

From time to time, Atlantic Power, its subsidiaries and the projects are parties to disputes and litigation that arise in the normal course of business. We assess our exposure to these matters and record estimated loss contingencies when a loss is likely and can be reasonably estimated. There are no matters pending as of December 31, 2010 that are expected to have a material impact on our financial position or results of operations.

## ITEM 4. (Reserved and Removed)

## PART II

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

### Market Information and Holders

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:

| Period | High (Cdn$) | Low (Cdn$) |
|---|---|---|
| Quarter ended December 31, 2010 | $15.18 | $13.31 |
| Quarter ended September 30, 2010 | 14.47 | 12.11 |
| Quarter ended June 30, 2010 | 12.90 | 11.20 |
| Quarter ended March 31, 2010 | 13.85 | 11.50 |
| Quarter ended December 31, 2009 | 11.90 | 9.08 |
| Quarter ended September 30, 2009 | 9.49 | 8.55 |
| Quarter ended June 30, 2009 | 9.45 | 7.71 |
| Quarter ended March 31, 2009 | 9.28 | 6.34 |

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:

| Period | High (US$) | Low (US$) |
|---|---|---|
| Quarter ended December 31, 2010 | $14.98 | $13.26 |
| July 23, 2010 through September 30, 2010 | 14.00 | 12.10 |

The number of holders of common stock was approximately 46,727 as of March 18, 2011.

### Dividends

Dividends declared per common share in 2010 and 2009 were as follows (Cdn$):

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

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

| | Units |
|---|---|
| Units authorized | 1,000,000 |
| Shares issued from long-term incentive plan | 193,678 |
| Remaining units authorized at December 31, 2010 | 806,322 |

## ITEM 6. SELECTED FINANCIAL DATA

The following table sets forth our selected historical consolidated financial information for each of the periods indicated. The annual historical information for each of the years in the three-year period ended December 31, 2010 has been derived from our audited consolidated financial statements included elsewhere in this Form 10-K.

You should read the following selected consolidated financial data along with "Management's Discussion and Analysis of Financial Condition and Results of Operations" and our consolidated financial statements and the accompanying notes, which are included elsewhere in Form 10-K and which describe the impact of material acquisitions and dispositions that occurred in the three-year period ended December 31, 2010.

| | Year Ended December 31, | | | | |
|---|---|---|---|---|---|
| (in thousands of U.S. dollars, except as otherwise stated) | 2010 | 2009 | 2008 | 2007 | 2006[a] |
| Project revenue | $ 195,256 | $179,517 | $173,812 | $113,257 | $ 69,374 |
| Project income | 41,879 | 48,415 | 41,006 | 70,118 | 57,247 |
| Net (loss) income attributable to Atlantic Power Corporation | (3,752) | (38,486) | 48,101 | (30,596) | (2,408) |
| Basic earnings per share, US$ | $ (0.06) | $ (0.63) | $ 0.78 | $ (0.50) | $ (0.05) |
| Basic earnings per share, Cdn$[b] | $ (0.06) | $ (0.72) | $ 0.84 | $ (0.53) | $ (0.06) |
| Diluted earnings per share, US$[c] | $ (0.06) | $ (0.63) | $ 0.73 | $ (0.50) | $ (0.05) |
| Diluted earnings per share, Cdn$[b][c] | $ (0.06) | $ (0.72) | $ 0.78 | $ (0.53) | $ (0.06) |
| Per IPS distribution declared | $ — | $ 0.51 | $ 0.60 | $ 0.59 | $ 0.57 |
| Per common share dividend declared | $ 1.06 | $ 0.46 | $ 0.40 | $ 0.40 | $ 0.37 |
| Total assets | $1,013,012 | $869,576 | $907,995 | $880,751 | $965,121 |
| Total long-term liabilities | $ 518,273 | $402,212 | $654,499 | $715,923 | $613,423 |

(a) Unaudited

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

(c) Diluted earnings (loss) per share US$ is computed including dilutive potential shares, which include those issuable upon conversion of convertible debentures and under our long term incentive plan. Because we reported a loss during the years ended December 31, 2010, 2009, 2007 and 2006, the effect of including potentially dilutive shares in the calculation during those periods is anti-dilutive. Please see the notes to our historical consolidated financial statements included elsewhere in this Form 10-K for information relating to the number of shares used in calculating basic and diluted earnings per share for the periods presented.

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

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

*This report contains, in addition to historical information, forward-looking statements that involve risks and uncertainties. These forward-looking statements reflect our current views about future events and financial performance. Investors should not rely on forward-looking statements because they are subject to a variety of factors that could cause actual results to differ materially from our expectations. Factors that could cause, or contribute to such differences include, without limitation, the factors described under Item 1A "Risk Factors." In view of these uncertainties, investors are cautioned not to place undue reliance on these forward-looking statements. We assume no obligation to update or revise publicly any forward-looking statements, whether as a result of new information, future events or otherwise.*

### Overview

Atlantic Power Corporation owns interest in power projects and one transmission line located in the United States. Our current portfolio consists of interests in 13 operational power generation projects across ten states, a 500 kilovolt 84-mile electric transmission line located in California, one biomass project under construction in Georgia and several development stage generating projects. Our power generation projects in operation have an aggregate gross electric generation capacity of approximately 1,962 megawatts ("MW"), in which our ownership interest is approximately 878 MW.

We sell the capacity and energy from our power generation projects under power purchase agreements (or "PPAs") with a variety of utilities and other parties. Under the PPAs, which have expiration dates ranging from 2011 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 (or "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 not a 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, Power Plant Management Services and the Western Area Power Administration. Under these operation, maintenance and management agreements, the operator is typically responsible for operations, maintenance and repair services.

We completed our initial public offering on the Toronto Stock Exchange (TSX: ATP) in November 2004. Our shares began trading on the NYSE under the symbol "AT" on July 23, 2010.

As of March 18, 2011, we had 68,108,042 common shares, Cdn$49.6 million principal amount of 6.50% convertible secured debentures due October 31, 2014 (the "2006 Debentures"), Cdn$76.7 million principal amount of 6.25% convertible debentures due March 15, 2017 (the "2009 Debentures"), and Cdn$80.5 million principal amount of 5.60% convertible debentures due June 30, 2017 (the "2010 Debentures" and together with the 2006 and 2009 Debentures, the "Debentures") outstanding. The

2006 Debentures, 2009 Debentures and 2010 Debentures are convertible at any time, at the option of the holder, into 80.645, 76.923 and 55.249, respectively, common shares per Cdn$1,000 principal amount of Debentures, representing a conversion price of Cdn$12.40, Cdn$13.00 and Cdn$18.10, respectively, per common share. Holders of common shares currently receive a monthly dividend at a current annual rate of Cdn$1.094 per common share.

On November 24, 2009, our shareholders approved our conversion from the previous Income Participating Security ("IPS") structure to a traditional common share structure. An IPS was comprised of one common share and Cdn$5.767 principal value of 11% subordinated notes due 2016. 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. This transaction resulted in the extinguishment of Cdn$347.8 million ($327.7 million) principal value of 11% subordinated notes due 2016 that previously formed a part of each IPS.

**Current Trends in Our Business**

*Macroeconomic impacts*

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

*Increased renewable power projects*

The combination of federal stimulus provisions, state renewable portfolio standards and state or regional $CO_2$/greenhouse gases reduction programs has provided powerful incentives to build new renewable power capacity. One simple impact of this trend is the offsetting reduction in new fossil-fired generation, with the following exception. Because significant renewable capacity is being built as intermittent resources (e.g., wind and solar) there will be an increased need by system operators to have more "firming resources." These are units that can be started quickly or idle at low levels in order to be available to compensate for sudden decreases in output from the solar or wind projects. These firming resources are generally natural gas-fired generators or, in more limited locations, pumped storage or reservoir-based hydro resources. The second significant impact of increased renewable projects is the increased need for new transmission lines to move power from renewable resources in typically more remote locations to the more highly-populated electricity load centers. This transmission requirement will require significant capital and tends to encounter a long and risky development and siting cycle.

*Increased shale gas resources*

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

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

*Credit markets*

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

**Factors That May Influence Our Results**

Our primary objective is to generate consistent levels of cash flow to support dividends to our shareholders, which we refer to as "Cash Available for Distribution." Because we believe that our shareholders are primarily focused on income and secondarily on capital appreciation, we provide supplementary cash flow-based non-GAAP information in this Item 7 and discuss our results in terms of these non-GAAP measures, in addition to analysis of our results on a GAAP basis. See "Supplementary Non-GAAP Financial Information" included elsewhere in this Form 10-K for additional details.

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

*Financial performance of our projects*

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

- While approximately 48% of our power generation revenue in 2010 was related to contractual capacity payments, commodity prices do influence our revenues and cost of fuel. Our PPAs are generally structured to minimize our risk to fluctuations in commodity prices by passing the cost of fuel through to the utility customers, but some of our projects do have exposure to market power and fuel prices. For example, a portion of the natural gas required for our Auburndale and Lake projects is purchased at spot market prices but not effectively passed through in their PPAs. Our Orlando project should benefit from switching to market prices for natural gas when its fuel contract expires in 2013 since the contract prices are above current and projected spot prices. We have executed a hedging strategy to partially mitigate this risk. See Item 7A "Quantitative and Qualitative Disclosures About Market Risk", in this Form 10-K for additional details about our hedging program at Auburndale, Lake and Orlando. Our most significant exposure to market power prices exists at the Selkirk and Chambers projects. At Chambers, our utility customer has the right to sell a portion of the plant's output to the spot power market if it is economical to do so, and the Chambers project shares in the profits from those sales. With low demand for electricity the utility reduces its dispatch to minimum contracted levels during off-peak hours. At Selkirk, approximately 23% of the capacity of the facility is currently not contracted and is sold at market power prices or not sold at all if market prices do not support profitable operation of that portion of the facility.

- When revenue or fuel contracts at our projects expire, we may not be able to sell power or procure fuel under new arrangements that provide the same level or stability of project cash flows. In particular, the power agreements for our Lake and Auburndale projects expire in 2013. We expect these projects to continue operating under new PPAs and generating Cash Available for Distribution after their existing power contracts expire, but at significantly lower levels. The degree of the expected decline in Cash Available for Distribution is subject to market conditions at such time as we execute new power agreements for these projects and cannot be estimated at this time. Both of these projects will be free of debt when their PPAs expire in 2013, which provides us with some flexibility to pursue the most economic type of contract without restrictions that are sometimes imposed by project-level debt.
- Some of our projects have non-recourse project-level debt that can restrict the ability of the project to make cash distributions. The project-level debt agreements typically contain cash flow coverage ratio tests that restrict the project's cash distributions if project cash flows do not exceed project-level debt service requirements by a specified amount. The Selkirk, Gregory and Delta-Person projects and Epsilon Power Partners, the holding company for our ownership in the Chambers project, are currently not meeting their cash flow coverage ratio tests and they are restricted from making cash distributions. We expect to resume receiving distributions from Epsilon Power Partners and Delta-Person in 2011, Selkirk in 2012 and Gregory in 2014. See the "Project-level debt" section of "Liquidity and Capital Resources" elsewhere in this Form 10-K for additional details.

*Non-cash gains and losses on derivatives instruments*

In the ordinary course of our business, we execute natural gas swap contracts to manage our exposure to fluctuations in commodity prices, forward foreign currency contracts to manage our exposure to fluctuations in foreign exchange rates and interest rate swaps to manage our exposure to changes in interest rates on variable rate project-level debt. Most of these contracts are recorded at fair value with changes in fair value recorded currently in earnings, resulting in significant volatility in our income that does not significantly affect current period cash flows or the underlying risk management purpose of the derivative instruments. See Item 7A, "Quantitative and Qualitative Disclosures About Market Risk", in this Form 10-K for additional details about our derivative instruments.

*Interest expense and other costs associated with debt*

Interest expense relates to both non-recourse project-level debt and corporate-level debt. In addition, in connection with our common share conversion transaction in 2009, we recorded $16.2 million of charges to interest expense associated with the costs of the conversion and the write-off of unamortized debt issuance costs associated with the subordinated notes that were retired. The conversion transaction resulted in Cdn$347.8 million ($327.7 million) of subordinated notes bearing interest at 11% being converted to equity and, as a result, we experienced a significant decrease in our interest expense beginning in 2010. Our convertible debentures are denominated in Canadian dollars and, prior to our common share conversion transaction, the outstanding subordinated notes were also denominated in Canadian dollars. These debt instruments are revalued at each balance sheet date based on the U.S. dollar to Canadian dollar foreign exchange rate at the balance sheet date, with changes in the value of the debt recorded in the consolidated statements of operations. The U.S. dollar to Canadian dollar foreign exchange rate has been volatile in recent years, which in turn creates volatility in our results due to the revaluation of our Canadian dollar-denominated debt.

**Outlook**

Based on our actual performance to date and projections for the remainder of the year, we expect to receive distributions from our projects in the range of $80 million to $90 million for the full year 2011. We expect overall levels of operating cash flows in 2011 to be improved over actual 2010 levels. Higher distributions from existing projects, initial distributions from our recent investment in Idaho Wind and Cadillac, and a slightly lower payment under the management termination agreement are expected to be partially offset by the non-recurrence of $8.0 million of cash tax refunds in 2010. In 2012, additional increases in distributions from projects are expected to further increase operating cash flow compared to 2011. The most significant factor in the expected higher operating cash flow in 2012 is increased distributions from Selkirk following the final payment of its non-recourse project-level debt in 2012.

The following items comprise the most significant increases in projected 2011 project distributions compared to 2010.

- lower fuel costs at the Lake project
- resumption of distributions from the Chambers project
- annual increase in contractual capacity payments from the Auburndale project
- distributions from the recently acquired Cadillac and Idaho Wind projects

In 2010, the following five projects comprised approximately 90% of project distributions received: Auburndale, Lake, Orlando, Path 15 and Pasco. For 2011, we expect these same five projects to contribute approximately 85% of total project distributions.

In addition to the items above, the following is a summary of other projections for project distributions in 2011 and beyond:

***Lake***

The Lake project is exposed to changes in natural gas prices from the expiration of its natural gas supply contract on June 30, 2009 through to the expiration of its PPA in July 2013 that are not passed through in its PPAs. We have executed a hedging strategy to mitigate this exposure by periodically entering into financial swaps that effectively fix the forward price of natural gas expected to be purchased at the project. These hedges are summarized in Item 7A, “Quantitative and Qualitative Disclosures About Market Risk”, in this Form 10-K. We intend to continue, when appropriate, to evaluate opportunities to further mitigate natural gas price exposure at Lake in 2013, but do not intend to execute additional hedges at Lake for 2011 and 2012 because our natural gas exposure for those years is already substantially hedged.

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

Coal prices used in the energy revenue component of the projected distributions from the Lake project incorporate a forecast of the applicable Crystal River facility coal cost provided by the utility based on their internal projections. The projected annual cash distributions change by approximately $1.0 million for every $0.25/Mmbtu change in the projected price of coal.

We expect to receive distributions from the Lake project of approximately $30 million to $34 million in both 2011 and 2012. The increases in 2011 and 2012 over the $28.8 million of distributions in 2010 are primarily due to higher contractual capacity payments and lower hedged natural gas prices than in 2010.

***Auburndale***

Based on the current forecast, we expect distributions from Auburndale of $25 million to $27 million per year from 2011 through 2013, when the project's current PPA expires. Distributions received from Auburndale in the 2011 through 2013 period will be impacted by projected coal and gas prices in the forecast period.

The projected revenue from the Auburndale PPA contains a component related to the costs of coal consumed at the utility off-taker's Crystal River facility as described above for the Lake project. Because that mechanism does not pass through changes in the project's fuel costs, Auburndale's operating margin is exposed to changes in natural gas prices for approximately 20% of its natural gas requirements through the expiration of the project's gas supply contract. The remaining 80% of the project's fuel requirements are supplied under an agreement with fixed prices through its expiration in mid-2012. We have been executing a strategy to mitigate the future exposure to changes in natural gas prices at Auburndale by periodically entering into financial swaps that effectively fix the forward price of natural gas required at the project. These hedges are summarized in Item 7A, "Quantitative and Qualitative Disclosures About Market Risk", in this Form 10-K. The 2011 natural gas price exposure at Auburndale has been substantially hedged. We intend to continue, when appropriate, to evaluate opportunities to further mitigate natural gas price exposure at Auburndale in 2012 and 2013.

***Chambers***

As previously reported, reduced cash flows resulted in the project not meeting cash flow coverage ratio tests in its non-recourse debt, so we received no distributions from Chambers in 2009 and in the first nine months of 2010. The Chambers project began to meet the cash flow coverage ratio for its non-recourse debt again as of September 30, 2010 and the project distributed $2.8 million to our project holding company, Epsilon Power Partners in October 2010. However, the required cash flow coverage ratio on the debt at Epsilon Power Partners has not been achieved and, as a result, Epsilon has not made any distributions to the Company during 2009 and 2010. Based on our current projections, Epsilon will continue receiving distributions from the project in 2011 based on meeting the required debt service coverage ratios and we expect Epsilon to resume making distributions to the Company in late 2011.

## Results of Operations

The following table and discussion is a summary of our consolidated results of operations for the years ended December 31, 2010, 2009 and 2008. The results of operations by segment are discussed in further detail following this consolidated overview discussion.

| | Year ended December 31, | | |
|---|---|---|---|
| **(in thousands of U.S. dollars, except as otherwise stated)** | **2010** | **2009** | **2008** |
| Project revenue | | | |
| Auburndale | $ 77,876 | $ 74,875 | $ 10,003 |
| Lake | 74,024 | 62,285 | 61,610 |
| Pasco | 11,305 | 11,357 | 58,897 |
| Path 15 | 31,000 | 31,000 | 31,528 |
| Chambers | — | — | — |
| Other Project Assets | 1,051 | — | 11,774 |
| | 195,256 | 179,517 | 173,812 |
| Project expenses | | | |
| Auburndale | 63,457 | 59,435 | 7,669 |
| Lake | 51,694 | 47,005 | 39,951 |
| Pasco | 9,594 | 11,044 | 48,098 |
| Path 15 | 10,748 | 11,819 | 10,573 |
| Chambers | 20 | — | — |
| Other Project Assets | 1,664 | (254) | 41 |
| | 137,177 | 129,049 | 106,332 |
| Project other income (expense) | | | |
| Auburndale | (10,222) | (4,950) | (225) |
| Lake | (8,721) | (5,060) | 33 |
| Pasco | 8 | 25 | (4,356) |
| Path 15 | (12,401) | (11,682) | (13,232) |
| Chambers | 10,289 | 3,906 | 11,218 |
| Other Project Assets | 4,847 | 15,708 | (19,912) |
| | (16,200) | (2,053) | (26,474) |
| Total project income | | | |
| Auburndale | 4,197 | 10,490 | 2,109 |
| Lake | 13,609 | 10,220 | 21,692 |
| Pasco | 1,719 | 338 | 6,443 |
| Path 15 | 7,851 | 7,499 | 7,723 |
| Chambers | 10,269 | 3,906 | 11,218 |
| Other Project Assets | 4,234 | 15,962 | (8,179) |
| | 41,879 | 48,415 | 41,006 |
| Administrative and other expenses | | | |
| Management fees and administration | 16,149 | 26,028 | 10,012 |
| Interest, net | 11,701 | 55,698 | 43,275 |
| Foreign exchange loss (gain) | (1,014) | 20,506 | (47,247) |
| Other (income) expense, net | (26) | 362 | 425 |
| Total administrative and other expenses | 26,810 | 102,594 | 6,465 |
| Income (loss) from operations before income taxes | 15,069 | (54,179) | 34,541 |
| Income tax expense (benefit) | 18,924 | (15,693) | (13,560) |
| Net (loss) income | (3,855) | (38,486) | 48,101 |
| Net loss attributable to noncontrolling interest | (103) | — | — |
| Net (loss) income attributable to Atlantic Power Corporation shareholders | $ (3,752) | $ (38,486) | $ 48,101 |

***Consolidated Overview***

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

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

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

Cash available for distribution was $65.5 million, $66.3 million and $91.0 million for the years ended December 31, 2010, 2009 and 2008, respectively. See "Cash Available for Distribution" elsewhere in this Form 10-K for additional information.

Income (loss) from operations before income taxes for the years ended December 31, 2010, 2009 and 2008 was $15.1 million, $(54.2) million and $34.5 million, respectively. See "Project Income" below for additional information.

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

***Project Income***

*Auburndale Segment*

The decrease in project income for our Auburndale segment of $6.3 million to $4.2 million in the year ended December 31, 2010 from $10.5 million in 2009 is primarily attributable to the $6.3 million increase in the charge associated with non-cash change in fair value of derivative instruments associated with its natural gas swaps. These swaps were executed to financially hedge the project's exposure to changes in the market prices of natural gas. See Item 7A, "Quantitative and Qualitative Disclosures About Market Risk", for additional details about our derivative instruments and other financial instruments. Project revenue at Auburndale increased by $3.0 million in 2010 due to favorable energy pricing compared to 2009, as well as the annual contractual escalation of capacity payments. This increased revenue was entirely offset by higher fuel and maintenance costs associated with the hot gas path inspection during 2010.

*Lake Segment*

Project income for our Lake segment increased $3.4 million to $13.6 million in the year ended December 31, 2010, from $10.2 million in 2009. The increase is primarily attributable to earnings from favorable off-peak dispatch during the summer months as well as the annual escalation of capacity payments, partially offset by higher fuel costs in 2010. In addition, there was a $3.7 million increase in the charge associated with the non-cash change in fair value of derivative instruments associated with its natural gas swaps. These swaps were executed to financially hedge the project's exposure to changes in the market prices of natural gas. See Item 7A, "Quantitative and Qualitative Disclosures About Market Risk", for additional details about our derivative instruments and other financial instruments.

*Pasco Segment*

The increase in project income for our Pasco segment of $1.4 million to $1.7 million in the year ended December 31, 2010 from $0.3 million in 2009 is due to lower operations and maintenance expenses attributable to an unplanned outage in 2009.

*Path 15 Segment*

Project income for our Path 15 segment increased $0.4 million to $7.9 million in the year ended December 31, 2010 from $7.5 million in 2009 due to lower interest and operations and maintenance expenses in 2010, partially offset by a non-recurring gain in the prior year related to the settlement of disputes with landowners over right-of-way issues.

*Chambers Segment*

Project income for our Chambers segment, which is recorded under the equity method of accounting, increased $6.4 million to $10.3 million in the year ended December 31, 2010 from $3.9 million in 2009. The increase in project income at Chambers is primarily attributable to lower maintenance costs as 2009 maintenance costs included a planned steam turbine overhaul, higher dispatch during a warmer summer in 2010 compared to 2009, and a $1.2 million non-cash change in fair value of derivative instruments associated with its interest rate swaps.

*Other Project Assets Segment*

Project income (loss) for our Other Project Assets segment decreased $11.7 million, to $4.2 million for the year ended December 31, 2010 compared to income of $15.9 million in 2009. The most significant components of the change are as follows:

- a non-cash gain in change in fair value of derivative instruments associated with the interest rate swap related to non-recourse construction financing at the Piedmont project;
- a pre-tax gain on sale of equity investment in the Rumford project of $1.5 million during the fourth quarter of 2010;
- a pre-tax long-lived asset impairment charge at the Topsham and Badger Creek projects of $2.0 million and $1.2 million, respectively, during the fourth quarter of 2010;
- a pre-tax long-lived asset impairment charge at the Rumford project of $5.5 million during the third quarter of 2009, partially offset by the absence of revenue at Rumford in 2010 as the contract that provided substantially all of the project's income expired in the fourth quarter of 2009; and
- a pre-tax gain on sale at the Mid-Georgia project of $15.8 million, which was sold in the fourth quarter of 2009.

***Administrative and Other Expenses (Income)***

Management fees and administration includes the costs of operating as a public company and, through December 2009, the fees and costs associated with our management by Atlantic Power Management, LLC (the "Manager"). Effective December 31, 2009, the Manager no longer provides management and administrative services for our company. The Manager is indirectly owned by the ArcLight Funds and received compensation in the form of an annual base fee that was indexed to inflation and an incentive fee that was equal to 25% of the cash distributions to shareholders in excess of Cdn$1.00 per year per IPS. We also reimbursed the Manager for reasonable costs incurred to manage our company. Management fees and administration decreased $9.9 million to $16.1 million for the year ended December 31, 2010 from $26.0 million in 2009. The decrease is attributable to the

$14.1 million charge associated with the termination of the management agreements at the end of 2009 offset by a $2.2 million increase in employee share-based compensation plan expense in 2010. The expense associated with the plan varies, in part, with the market price of our common shares, which increased significantly during the year ended December 31, 2010 compared to the year ended December 31, 2009, resulting in higher expense in 2010. In addition, we incurred $1.0 million of expenses associated with our initial NYSE listing completed in July 2010 and business development costs associated with potential acquisitions.

Interest expense at the corporate level in 2010 primarily relates to our convertible debentures. Interest expense, net decreased $44.0 million to $11.7 million in 2010 from $55.7 million in 2009. This decrease is primarily due to the extinguishment of the subordinated notes that were outstanding during 2009. In November 2009 we completed our common share conversion, which resulted in the extinguishment of Cdn$347.8 million ($327.7 million) principal value of 11% subordinated notes due 2016 that previously formed a part of each IPS.

Foreign exchange loss (gain) primarily reflects the unrealized impact of changes in foreign exchange rates on the U.S. dollar equivalent of our Canadian dollar-denominated obligations to holders of the convertible debentures and, through 2009, our subordinated notes. In addition, unrealized and realized gains and losses on our forward contracts for the purchase of Canadian dollars to satisfy these obligations and our dividends to shareholders are included in foreign exchange loss (gain). Unrealized gains and losses on our forward contracts are reclassified to realized gains and losses upon cash settlement of the contracts. Foreign exchange (gain) loss increased $21.5 million to a $1.0 million gain in 2010 compared to a $20.5 million loss in 2009. The U.S. dollar to Canadian dollar exchange rate decreased by 5.7% during the year ended December 31, 2010, compared to a decrease of 15.9% in the comparable period in 2009. See Item 7A "Quantitative and Qualitative Disclosures About Market Risk" for additional details about our management of foreign currency risk and the components of the foreign exchange loss (gain) recognized during the year ended December 31, 2010 compared to the foreign exchange loss (gain) in 2009.

***Year ended December 31, 2009 compared with Year ended December 31, 2008***

***Project Income***

*Auburndale Segment*

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

*Lake Segment*

Project income for our Lake segment decreased $11.5 million, or 53%, to $10.2 million in 2009 from $21.7 million in 2008. The decrease is primarily attributable to higher fuel expense at Lake due to the expiration of its natural gas supply agreement as of June 30, 2009. A new gas supply agreement at higher prices was effective for the second half of 2009. In addition, non-cash losses associated with natural gas swaps were recorded in the change in fair value of derivative instruments during 2009 of $5.1 million. These swaps were executed to financially hedge the project's exposure to changes in the market prices of natural gas. See Item 7A, "Quantitative and Qualitative Disclosures About Market Risk", for additional details about our derivative instruments and other financial instruments.

*Pasco Segment*

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

*Path 15 Segment*

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

*Chambers Segment*

Project income for our Chambers segment, which is recorded under the equity method of accounting, decreased $7.3 million, or 65%, to $3.9 million in 2009 from $11.2 million in 2008 as a result of $9.4 million lower gross margin due to lower electricity sales volumes and prices throughout 2009 and a $4.6 million increase in operation and maintenance costs from a planned major maintenance outage in the second quarter of 2009. In addition, non-cash gains of $2.6 million associated with interest swaps were recorded in the change in fair value of derivative instruments during 2009 compared to $4.3 million of losses in 2008.

*Other Project Assets Segment*

Project income (loss) for our Other Project Assets segment increased $24.1 million, to $15.9 million in 2009 compared to an $(8.2) million loss in 2008, primarily due to the following:

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

***Administrative and Other Expenses (Income)***

Management fees and administration increased $16 million, or 160%, to $26 million in 2009 from $10.0 million in 2008. The increase is primarily attributable to a $14.1 million charge associated with the termination of the management agreements at the end of 2009. In addition, employee and director share-based compensation plan expense increased in 2009. The expense associated with these plans varies, in part, with the market price of our common shares, which increased significantly during 2009 compared to a decrease during the twelve months of 2008, resulting in higher expense in the 2009 period.

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

Foreign exchange loss (gain) primarily reflects the unrealized impact of changes in foreign exchange rates on the U.S. dollar equivalent of our Canadian dollar-denominated obligations to holders of subordinated notes and debentures. In addition, unrealized and realized gains and losses on our forward contracts for the purchase of Canadian dollars to satisfy these obligations are included in foreign exchange loss (gain). Foreign exchange loss (gain) increased $67.7 million to a $20.5 million loss in 2009 compared to a $(47.2 million) gain in 2008. The U.S. dollar to Canadian dollar exchange rate decreased by 15.9% during the year ended December 31, 2009. During the year ended December 31, 2008, the rate increased by 18.6%. See Item 7A, "Quantitative and Qualitative Disclosures About Market Risk", below for additional details about our management of foreign currency risk and the components of the foreign exchange loss (gain) recognized during the year ended December 31, 2009 compared to the foreign exchange loss (gain) in 2008.

***Supplementary Non-GAAP Financial Information***

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

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

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

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

| | Year ended December 31, | | |
|---|---|---|---|
| | 2010 | 2009 | 2008 |
| **Project Adjusted EBITDA by individual segment** | | | |
| Auburndale | $ 34,232 | $ 35,221 | $ 4,461 |
| Lake | 31,428 | 25,378 | 32,892 |
| Pasco | 4,712 | 3,299 | 21,953 |
| Path 15 | 28,639 | 27,691 | 28,872 |
| Chambers | 19,344 | 13,595 | 27,603 |
| **Total** | 118,355 | 105,184 | 115,781 |
| **Other Project Assets segment** | | | |
| Mid-Georgia | — | 2,509 | 4,206 |
| Stockton | — | (675) | 1,780 |
| Badger Creek | 3,062 | 3,245 | 3,762 |
| Koma Kulshan | 812 | 822 | 912 |
| Onondaga | | — | 7,865 |
| Orlando | 7,883 | 8,858 | 8,206 |
| Topsham | 1,890 | 1,879 | 2,629 |
| Delta-Person | 1,849 | 894 | 2,012 |
| Gregory | 4,822 | 4,482 | 5,236 |
| Rumford | (7) | 2,590 | 2,395 |
| Selkirk | 14,931 | 15,059 | 19,104 |
| Rollcast | (987) | (234) | — |
| Other | (26) | (434) | 801 |
| **Total adjusted EBITDA from Other Project Assets segment** | 34,229 | 38,995 | 58,908 |
| **Project income** | | | |
| Total adjusted EBITDA from all Projects | 152,584 | 144,179 | 174,689 |
| Depreciation and amortization | 65,791 | 67,643 | 60,125 |
| Interest expense, net | 23,628 | 31,511 | 30,316 |
| Change in the fair value of derivative instruments | 17,643 | 5,047 | 29,914 |
| Other (income) expense | 3,643 | (8,437) | 13,328 |
| **Project income as reported in the statement of operations** | $ 41,879 | $ 48,415 | $ 41,006 |

**Reconciliation of Project Distributions to EBITDA (in thousands of U.S. dollars)**
**For the year ended December 31, 2010**

| | Project Adjusted EBITDA | Repayment of long-term debt | Interest expense, net | Capital expenditures | Change in working capital & other items | Project distribution received |
|---|---|---|---|---|---|---|
| **Reportable Segments** | | | | | | |
| Auburndale | $ 34,232 | $ (9,800) | $ (1,631) | $ (29) | $ 4,628 | $27,400 |
| Chambers | 19,344 | (12,052) | (6,260) | (42) | (990) | — |
| Lake | 31,428 | — | 9 | (1,693) | (996) | 28,748 |
| Pasco | 4,712 | — | 8 | (568) | 103 | 4,255 |
| Path 15 | 28,639 | (7,480) | (12,401) | — | (819) | 7,939 |
| Total Reportable Segments | 118,355 | (29,332) | (20,275) | (2,332) | 1,926 | 68,342 |
| **Other Project Assets Segment** | | | | | | |
| Badger Creek | 3,062 | — | (15) | — | (156) | 2,891 |
| Delta-Person | 1,849 | (1,559) | (274) | — | (16) | — |
| Gregory | 4,822 | (1,689) | (296) | (90) | (1,325) | 1,422 |
| Koma Kulshan | 812 | — | 1 | (28) | 179 | 964 |
| Orlando | 7,883 | — | 3 | (405) | (606) | 6,875 |
| Rumford | (7) | — | — | — | 7 | — |
| Selkirk | 14,931 | (8,863) | (2,087) | (79) | (3,902) | — |
| Topsham | 1,890 | — | — | — | (1) | 1,889 |
| Rollcast | (987) | — | 3 | (40) | 1,024 | — |
| Other | (26) | (600) | (688) | (259) | 2,030 | 457 |
| Total Other Project Assets Segment | 34,229 | (12,711) | (3,353) | (901) | (2,766) | 14,498 |
| Total all Segments | $152,584 | $(42,043) | $(23,628) | $(3,233) | $ (840) | $82,840 |

**Reconciliation of Project Distributions to EBITDA (in thousands of U.S. dollars)**
**For the year ended December 31, 2009**

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

**Reconciliation of Project Distributions to EBITDA (in thousands of U.S. dollars)**
**For the year ended December 31, 2008**

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

***Project Operations Performance—Year ended December 31, 2010 compared with Year ended December 31, 2009***

Aggregate Project Adjusted EBITDA increased $8.4 million to $152.6 million in the year ended December 31, 2010 from $144.2 million in 2009 and included the following factors:

- increased EBITDA of $6.1 million at Lake due to earnings from favorable off-peak dispatch during the summer months and increased contractual capacity payments under the project's PPA;
- increased EBITDA of $5.7 million at Chambers due to lower operations and maintenance costs in 2010 as compared to 2009, which had a planned steam turbine generator overhaul outage, as well as higher generation due to better market prices on the ACE PPA;
- increased EBITDA of $1.4 million at Pasco primarily attributable to a maintenance outage during the year ended December 31, 2009; partially offset by
- decreased EBITDA of $1.0 million at Auburndale due to higher maintenance costs in 2010 and a longer scheduled down-time during a planned outage;
- the absence of Rumford EBITDA as the project was sold in the fourth quarter of 2010; and

- the absence of Stockton and Mid-Georgia's EBITDA as both projects were sold in the fourth quarter of 2009.

Aggregate power generation for projects in operation at December 31, 2010 was 2.5% less than the year ended December 31, 2009. Generation during the year ended December 31, 2010 compared to the prior year was favorably impacted primarily by increased generation at Lake associated with dispatch during off-peak hours due to favorable market conditions, Chambers due to higher dispatch also as a result of favorable market conditions. The favorable variance was offset by the absence of Stockton and Mid-Georgia generation as the projects were sold in the fourth quarter of 2009 and by lower Phase II dispatch at Selkirk.

The project portfolio achieved a weighted average availability of 95.3% for the year ended December 31, 2010 compared to 95.1% in the 2009 period. The increase in portfolio availability for the year ended December 31, 2010 was primarily due to planned and forced outages at Chambers and Badger, respectively, in 2009 offset by planned outages at Lake and Auburndale in 2010. Each of the projects with reduced availability was nevertheless able to achieve substantially all of their respective capacity payments as a result of contract terms that provide for certain levels of planned and unplanned outages.

***Project Operations Performance—Year ended December 31, 2009 compared with Year ended December 31, 2008***

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

- increased EBITDA attributable to the acquisition of the Auburndale project in November 2008;
- decreased EBITDA at Chambers attributable to lower levels of dispatch by the utility off-taker in connection with reduced demand and lower natural gas and power prices in the region. Operating the plant at a lower capacity factor also decreased its efficiency, further contributing to reduced operating margins. Additionally, decreased EBITDA attributable to a planned major outage at Chambers in the second quarter of 2009;
- decreased EBITDA at Lake attributable to higher fuel expense resulting from natural gas purchases at higher prices than those under the supply contract that expired in June 2009. We have a hedging strategy to mitigate its future exposure to changes in natural gas prices. See "Quantitative and Qualitative Disclosures About Market Risk" for additional information;
- decreased EBITDA at Pasco due to the commencement of the project's new ten-year tolling agreement on January 1, 2009 at lower rates than the power purchase agreement that expired December 31, 2008; and
- the absence of EBITDA at Onondaga as the contracts that provided substantially all of the project's cash flow expired in the second quarter of 2008.

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

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

**Cash Flow from Operating Activities**

Our cash flow from the projects may vary from year to year based on, among other things, changes in prices under the PPAs, fuel supply and transportation agreements, steam sales agreements and other project contracts, changes in regulated transmission rates, compliance with the terms of non-recourse project-level financing including debt repayment schedules, the transition to market or recontracted pricing following the expiration of PPAs, fuel supply and transportation contracts, working capital requirements and the operating performance of the projects. Project cash flows may have some seasonality and the pattern and frequency of distributions to us from the projects during the year can also vary, although such seasonal variances do not typically have a material impact on our business.

Cash flow from operating activities increased by $36.5 million for the year ended December 31, 2010 over the comparable period in 2009. The change from the prior year is primarily attributable to a significant decrease in cash interest expense as a result of our common share conversion in November 2009, which eliminated Cdn$347.8 million ($327.7 million) of outstanding subordinated notes, as well as higher net cash tax refunds of $8.0 million. The positive change in operating cash flow attributable to the reduced interest expense was partially offset by a $5.8 million decrease in distributions from our Orlando project and no distributions in 2010 from our Selkirk project, both of which are equity method investments. The decrease in distributions from Orlando was the result of a one-time receipt of insurance proceeds in 2009 related to an unplanned outage that occurred in 2008. The Selkirk project is currently not making distributions to partners as a result of restrictions in its non-recourse project-level debt. We expect to resume receiving distributions from Selkirk in late 2011 or early 2012.

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

**Cash Flow from Investing Activities**

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

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

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

**Cash Flow from Financing Activities**

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

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

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

**Cash Available for Distribution**

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

The table below presents our calculation of cash available for distribution for the years ended December 31, 2010, 2009 and 2008:

| (unaudited)<br>(in thousands of U.S. dollars, except as otherwise stated) | Year ended December 31, 2010 | 2009 | 2008 |
|---|---|---|---|
| Cash flows from operating activities | $ 86,953 | $ 50,449 | $ 77,788 |
| Project-level debt repayments | (18,882) | (12,744) | (22,275) |
| Interest on IPS portion of subordinated notes[1] | — | 30,639 | 36,560 |
| Purchases of property, plant and equipment[2] | (2,549) | (2,016) | (1,102) |
| Cash Available for Distribution[3] | 65,522 | 66,328 | 90,971 |
| Interest on subordinated notes | — | 30,639 | 36,560 |
| Dividends on common shares | 65,648 | 27,988 | 24,692 |
| Total distributions to shareholders | $ 65,648 | $ 58,627 | $ 61,252 |
| Payout ratio | 100% | 88% | 67% |
| *Expressed in Cdn$* | | | |
| Cash Available for Distribution | 67,540 | 75,673 | 97,102 |
| Total common share distributions | 67,914 | 66,325 | 65,143 |

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

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

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

## Liquidity and Capital Resources

### *Overview*

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

We believe that we will be able to generate sufficient amounts of cash and cash equivalents to maintain our operations and meet obligations as they become due.

With the exception of our commitment to the construction of Piedmont Green Power, we do not expect any material unusual requirements for cash outflows for 2011 for capital expenditures or other required investments. We expect to contribute approximately $75.0 million to fund the equity portion of the construction costs for Piedmont. Approximately $59.0 million of this amount has been contributed in the fourth quarter of 2010, with the remaining balance to be paid in the first quarter of 2011. In addition, there are no debt instruments with significant maturities or refinancing requirements in 2011.

See “Outlook” above for information about changes in expected distributions from our projects in 2011 and beyond.

***Credit facility***

We maintain a credit facility with a capacity of $100 million, $50 million of which may be utilized for letters of credit. The credit facility matures in August 2012.

The credit facility bears interest at the London Interbank Offered Rate (“LIBOR”) plus an applicable margin between 1.5% and 3.25% that varies based on the credit statistics of one of our subsidiaries. As of December 31, 2010, the applicable margin was 1.5%. As of December 31, 2010, $48.6 million was allocated, but not drawn, to support letters of credit for contractual credit support at eight of our projects. In June 2010, we borrowed $20 million under the credit facility and used the proceeds to partially fund the acquisition of Idaho Wind in July 2010. In October 2010, we repaid the $20 million borrowing with proceeds from our common stock and convertible debt offerings.

We must meet certain financial covenants under the terms of the credit facility, which are generally based on the cash flow coverage ratios and also require us to report indebtedness ratios to our lenders. The facility is secured by pledges of assets and interests in certain subsidiaries. We expect to remain in compliance with the covenants of the credit facility for at least the next 12 months.

***Convertible Debentures***

In October 2006, we issued, in a public offering, Cdn$60 million aggregate principal amount of 6.25% convertible secured debentures, which we refer to as the 2006 Debentures, for gross proceeds of $52.8 million. The 2006 Debentures pay interest semi-annually on April 30 and October 31 of each year. The Debentures initially had a maturity date of October 31, 2011 and are convertible into approximately 80.6452 common shares per Cdn$1,000 principal amount of 2006 Debentures, at any time, at the option of the holder, representing a conversion price of Cdn$12.40 per common share. The 2006 Debentures are secured by a subordinated pledge of our interest in certain subsidiaries and contain certain restrictive covenants. In connection with our conversion to a common share structure on November 27, 2009, the holders of the 2006 Debentures approved an amendment to increase the annual interest rate from 6.25% to 6.50% and separately, an extension of the maturity date from October 2011 to October 2014. During fiscal year 2010 and fiscal year 2011 through March 18, 2011, Cdn$4.2 million and Cdn$6.2 million of the 2006 Debentures, respectively, were converted to 0.3 million and 0.5 million common shares, respectively. As of March 18, 2011 the 2006 Debentures balance is Cdn$49.6 million ($50.8 million).

In December 2009, we issued, in a public offering, Cdn$86.25 million aggregate principal amount of 6.25% convertible unsecured subordinated debentures, which we refer to as the 2009 Debentures, for gross proceeds of $82.1 million. The 2009 Debentures pay interest semi-annually on March 15 and September 15 of each year beginning September 15, 2010. The 2009 Debentures mature on March 15, 2017 and are convertible into approximately 76.9231 common shares per Cdn$1,000 principal amount of 2009 Debentures, at any time, at the option of the holder, representing a conversion price of Cdn$13.00 per common share. During fiscal year 2010 and fiscal year 2011 through March 18, 2011, Cdn$3.1 million and Cdn$6.4 million of the 2009 Debentures, respectively, were converted to 0.2 million and 0.5 million common shares, respectively. As of March 18, 2011 the 2009 Debentures balance is Cdn$76.7 million ($78.6 million).

In October 2010, we issued, in a public offering, Cdn$80.5 million aggregate principal amount of 5.60% convertible unsecured subordinated debentures, which we refer to as the 2010 Debentures, for gross proceeds of $78.9 million. The 2010 Debentures pay interest semi-annually on June 30 and December 30 of each year beginning June 30, 2011. The 2010 Debentures mature on June 30, 2017, unless earlier redeemed. The debentures are convertible into our common shares at an initial conversion rate of 55.2486 common shares per Cdn$1,000 principal amount of debentures, representing an initial conversion price of approximately Cdn$18.10 per common share. As of March 18, 2011 the 2010 debentures balance is Cdn$80.5 million ($82.5 million).

***Project-level debt***

The following table summarizes the maturities of project-level debt. The amounts represent our share of the non-recourse project-level debt balances at December 31, 2010 and exclude any purchase accounting adjustments recorded to adjust the debt to its fair value at the time the project was acquired. Certain of the projects have more than one tranche of debt outstanding with different maturities, different interest rates and/or debt containing variable interest rates. Project-level debt agreements contain covenants that restrict the amount of cash distributed by the project if certain debt service coverage ratios are not attained. As of December 31, 2010, the covenants at the Selkirk, Gregory and Delta-Person projects and at Epsilon Power Partners are temporarily preventing those projects from making cash distributions to us. We expect to resume receiving distributions from Epsilon Power Partners and Delta-Person in 2011, Selkirk in 2012 and Gregory in 2014. All project-level debt is non-recourse to us and substantially the entire principal is amortized over the life of the projects' PPAs. The non-recourse holding company debt relating to our investment in Chambers is held at Epsilon Power Partners, our wholly-owned subsidiary. For the year ended December 31, 2010, we have contributed approximately $3.1 million to Epsilon Power Partners for debt service payments on the holding company debt and an additional $0.48 million in January 2011 but do not anticipate any additional required contributions to Epsilon.

The range of interest rates presented represents the rates in effect at December 31, 2010. The amounts listed below are in thousands of U.S. dollars, except as otherwise stated.

| | Range of Interest Rates | Total Remaining Principal Repayments | 2011 | 2012 | 2013 | 2014 | 2015 | Thereafter |
|---|---|---|---|---|---|---|---|---|
| **Consolidated Projects:** | | | | | | | | |
| Epsilon Power Partners | 7.40% | $ 36,482 | $ 1,500 | $ 1,500 | $ 3,000 | $ 5,000 | $ 5,750 | $ 19,732 |
| Path 15 | 7.9% - 9.0% | 153,868 | 7,987 | 8,667 | 9,402 | 8,065 | 8,749 | 110,998 |
| Auburndale | 5.10% | 21,700 | 9,800 | 7,000 | 4,900 | — | — | — |
| Cadillac | 7.2% - 8.0% | 42,531 | 2,300 | 3,791 | 2,400 | 2,000 | 2,500 | 29,540 |
| Total Consolidated Projects | | 254,581 | 21,587 | 20,958 | 19,702 | 15,065 | 16,999 | 160,270 |
| **Equity Method Projects:** | | | | | | | | |
| Chambers | 0.4% - 7.2% | 75,045 | 11,294 | 12,176 | 10,783 | 5,780 | 5,213 | 29,799 |
| Delta-Person | 2.0% | 10,521 | 1,130 | 1,212 | 1,300 | 1,394 | 1,495 | 3,990 |
| Selkirk | 9.0% | 16,793 | 10,948 | 5,845 | — | — | — | — |
| Gregory | 1.8% - 7.5% | 14,350 | 1,901 | 2,044 | 2,205 | 2,385 | 2,492 | 3,323 |
| Idaho Wind | 2.8% - 7.5% | 71,008 | 34,198 | 1,657 | 1,753 | 1,939 | 2,020 | 29,441 |
| Total Equity Method Projects | | 187,717 | 59,471 | 22,934 | 16,041 | 11,498 | 11,220 | 66,553 |
| Total Project-Level Debt | | $442,298 | $81,058 | $43,892 | $35,743 | $26,563 | $28,219 | $226,823 |

We also obtained project-level bank financing for Piedmont. The terms of the financing include an $82.0 million construction and term loan and a $51.0 million bridge loan for approximately 95.0% of the stimulus grant expected to be received from the U.S. Treasury 60 days after the start of commercial operations.

***Restricted cash***

The projects generally have reserve requirements to support payments for major maintenance costs and project-level debt service. For projects that are consolidated, our share of these amounts is reflected as restricted cash on the consolidated balance sheet. At December 31, 2010, restricted cash at the consolidated projects totaled $15.7 million.

**Capital Expenditures**

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

In 2011, several of the projects have planned outages to complete maintenance work. The level of maintenance and capital expenditures is slightly higher than in 2010. During 2010, Selkirk completed a minor inspection of one of its combustion turbines, with costs and lost margin largely covered by reserves and gas resales proceeds, respectively. Selkirk's planned major overhaul of a steam turbine has been postponed to 2011 due to maintaining a high steam quality. In the second quarter of 2010, Chambers completed its scheduled outage to inspect and complete customary repairs on one boiler. Due to the facility's low dispatch, the planned outage of its other boiler originally scheduled for the fourth quarter of 2010 has been postponed to 2011. At Orlando, a minor gas turbine inspection was completed in May, the cost of which was largely covered under its long-term maintenance agreement with the gas turbine manufacturer. During the fourth quarter of 2010, Auburndale conducted an inspection of one of the facility's combustion turbines, which is covered by its long-term service agreement, in conjunction with other maintenance work.

In 2010, we incurred approximately $48.0 million in capital expenditures for the construction of our Piedmont biomass project. In 2011, we expect to incur approximately $95.0 million in capital expenditures related to the Piedmont project, with total project costs through expected completion in late 2012 of approximately $207.0 million. The project will be funded with an $82.0 million construction loan which will convert to a term loan upon commercial operation, a $51.0 million bridge loan and approximately $75.0 million of equity contributed by Atlantic Power. The bridge loan will be repaid from the proceeds of a federal stimulus grant which is expected to be received two months after achieving commercial operation.

**Contractual Obligations and Commercial Commitments**

The following table summarizes our contractual obligations as of December 31, 2010 (in thousands of U.S. dollars).

| | Less than 1 Year | 1 - 3 Years | 3 - 5 Years | Thereafter | Total |
|---|---|---|---|---|---|
| Debt[(a)] | $ 21,587 | $111,829 | $216,953 | $124,829 | $475,198 |
| Interest payments on debt | 31,824 | 84,008 | 57,177 | 48,254 | 221,263 |
| Total operating lease obligation | 922 | 1,949 | 78 | — | 2,949 |
| Total purchase obligations[(b)] | 102,730 | 50,830 | 6,649 | 17,572 | 177,781 |
| Total other long-term liabilities | 5,914 | 2,048 | — | 791 | 8,753 |
| Total contractual obligations | $162,977 | $250,664 | $280,857 | $191,446 | $885,944 |

(a) Debt represents our consolidated share of project long-term debt and corporate-level debt. The amount presented excludes the net unamortized purchase price adjustment of $11.3 million related to the fair value of debt assumed in the Path 15 acquisition. Project debt is non-recourse to us and is generally amortized during the term of the respective revenue generating contracts of the projects. The range of interest rates on long-term consolidated project debt at December 31, 2010 was 5.1% to 9.0%.

(b) Included in purchase obligations is $131.7 million related to construction costs for our Piedmont project.

**Off-Balance Sheet Arrangements**

As of December 31, 2010, we had no off-balance sheet arrangements as defined in Item 303(a)(4) of Regulation S-K.

**Critical Accounting Policies and Estimates**

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

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

For a summary of our significant accounting policies, see Note 2 to our consolidated financial statements included in this Form 10-K. We believe that certain accounting policies are of more significance in our consolidated financial statement preparation process than others; these policies are discussed below.

*Impairment of long-lived assets and equity investments*

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

Investments in and the operating results of 50%-or-less owned entities not required to be consolidated are included in the consolidated financial statements on the basis of the equity method of accounting. We review our investments in unconsolidated entities for impairment whenever events or changes in business circumstances indicate that the carrying amount of the investments may not be fully recoverable. Evidence of a loss in value that is other than temporary might include the absence of an ability to recover the carrying amount of the investment, the inability of the investee to sustain an earnings capacity which would justify the carrying amount of the investment, failure of cash flow coverage ratio tests included in project-level, non-recourse debt or, where applicable, estimated sales proceeds which are insufficient to recover the carrying amount of the investment. Our assessment as to whether any decline in value is other than temporary is based on our ability and intent to hold the investment and whether evidence indicating the carrying value of the investment is recoverable within a reasonable period of time outweighs evidence to the contrary.

When we determine that an impairment test is required, the future projected cash flows from the equity investment are the most significant factor in determining whether impairment exists and, if so, the amount of the impairment charges. We use our best estimates of market prices of power and fuel and our knowledge of the operations of the project and our related contracts when developing these cash flow estimates. In addition, when determining fair value using discounted cash flows, the discount rate used can have a material impact on the fair value determination. Discount rates are based on our risk of the cash flows in the estimate, including, when applicable, the credit risk of the counterparty that is contractually obligated to purchase electricity or steam from the project.

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

*Fair Value of Derivatives*

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

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

A fair value hierarchy exists for inputs used in measuring fair value that maximizes the use of observable inputs (Level 1 or Level 2) and minimizes the use of unobservable inputs (Level 3) by requiring that the observable inputs be used when available. Our derivative instruments are classified as Level 2. The fair value measurements of these derivative assets and liabilities are based largely on quoted prices from independent brokers in active markets who regularly facilitate our transactions. An active market is considered to have transactions with sufficient frequency and volume to provide pricing information on an ongoing basis.

Derivative assets are discounted for credit risk using credit spreads representative of the counterparty's probability of default. For derivative liabilities, fair value measurement reflects the nonperformance risk related to that liability, which is our own credit risk. We derive our nonperformance risk by applying credit spreads approximating our estimate of corporate credit rating against the respective derivative liability.

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

*Income Taxes and Valuation Allowance for Deferred Tax Assets*

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

*Long-term incentive plan*

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

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

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

## ITEM 7A. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

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

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

**Fuel Commodity Market Risk**

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

The Lake project's operating margin is exposed to changes in the market price of natural gas from the expiration of its natural gas supply contract on June 30, 2009 through to the expiration of its PPA on July 31, 2013 not passed through in their PPAs. The Auburndale project purchases natural gas under a fuel supply agreement which provides approximately 80% of the project's fuel requirements at fixed prices through June 30, 2012. The remaining 20% is purchased at market prices and therefore the project is exposed to changes in natural gas prices for that portion of its gas requirements through the termination of the fuel supply agreement and 100% of its natural gas requirements from the expiration of the fuel contract in mid-2012 until the termination of its PPA at the end of 2013.

We have executed a strategy to mitigate the future exposure to changes in natural gas prices at Lake and Auburndale by periodically entering into financial swaps that effectively fix the price of natural gas required at these projects. These natural gas swaps are derivative financial instruments and are recorded in the consolidated balance sheet at fair value. Changes in the fair value of the natural gas swaps at Lake and Auburndale, through June 30, 2009 were recorded in other comprehensive income (loss) as they were designated as a hedge of the risk associated with changes in market prices of natural gas. As of July 1, 2009, these natural gas swap hedges were de-designated and the changes in their fair value are recorded in change in fair value of derivative instruments in the consolidated statements of operations.

In 2011, projected cash distributions at Auburndale would change by approximately $0.8 million per $1.00/Mmbtu change in the price of natural gas based on the current level of un-hedged natural gas volumes at the project. In 2011, projected cash distributions at Lake would change by approximately $0.8 million per $1.00/Mmbtu change in the price of natural gas based on the current level of un-hedged natural gas volumes at the project.

Coal prices used in the revenue component of the projected distributions from the Lake and Auburndale projects incorporate a forecast of the applicable Crystal River facility coal cost provided by the utility based on their internal projections. The projected annual cash distributions from Lake and Auburndale combined would change by approximately $2.5 million for every $0.25/Mmbtu change in the projected price of coal.

The following table summarizes the hedge position related to natural gas needed to meet PPA requirements at Lake and Auburndale as of December 31, 2010 and March 18, 2011:

| | 2011 | 2012 | 2013 |
|---|---|---|---|
| *As of December 31, 2010* | | | |
| Portion of gas volumes currently hedged: | | | |
| Lake: | | | |
| Contracted | — | — | — |
| Financially hedged | 78% | 90% | 65% |
| Total | 78% | 90% | 65% |
| Auburndale: | | | |
| Contracted | 80% | 40% | 0% |
| Financially hedged | 13% | 32% | 79% |
| Total | 93% | 72% | 79% |
| Average price of financially hedged volumes (per Mmbtu) | | | |
| Lake | $6.52 | $6.90 | $7.05 |
| Auburndale | $6.68 | $6.51 | $6.92 |

| | 2011 | 2012 | 2013 |
|---|---|---|---|
| *As of March 18, 2011* | | | |
| Portion of gas volumes currently hedged: | | | |
| Lake: | | | |
| Contracted | — | — | — |
| Financially hedged | 78% | 90% | 83% |
| Total | 78% | 90% | 83% |
| Auburndale: | | | |
| Contracted | 80% | 40% | 0% |
| Financially hedged | 13% | 32% | 79% |
| Total | 93% | 72% | 79% |
| Average price of financially hedged volumes (per Mmbtu) | | | |
| Lake | $6.52 | $6.90 | $6.63 |
| Auburndale | $6.68 | $6.51 | $6.92 |

On October 18, 2010, we entered into natural gas swaps that are effective in 2014 and 2015. The natural gas swaps are related to our 50% share of expected fuel purchases at our Orlando project as its operating margin is exposed to changes in natural gas prices following the expiration of its fuel contract at the end of 2013. These financial swaps effectively fix the price of 1.2 million Mmbtu of natural gas at the Orlando project at a weighted average price of $5.76/Mmbtu and represent approximately 25% of our share of the expected natural gas purchases at the project during 2014 and 2015.

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

**Foreign Currency Exchange Risk**

We use forward foreign currency contracts to manage our exposure to changes in foreign exchange rates as we earn our income in U.S. dollars but pay dividends to shareholders in Canadian dollars.

Since our inception, we have had an established hedging strategy for the purpose of mitigating the currency risk impact on the long-term sustainability of our dividends to shareholders. We have executed this strategy by entering into forward contracts to purchase Canadian dollars at fixed rates of exchange to hedge approximately 86% of our expected dividend and convertible debenture interest payments through 2013. Changes in the fair value of the forward contracts partially offset foreign exchange gains or losses on the U.S. dollar equivalent of our Canadian dollar obligations. The forward contracts consist of (1) monthly purchases through the end of 2013 of Cdn$6.0 million at an exchange rate of Cdn$1.134 per U.S. dollar and (2) purchases in both April and October 2011 of Cdn$1.9 million at an exchange rate of Cdn$1.1075 per U.S. dollar.

It is our intention to periodically consider extending the length of these forward contracts. In addition, we will consider executing additional foreign currency forward contracts to hedge expected additional dividend and interest payments associated with the common shares and convertible debentures issued in our October 2010 public offering.

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

The following table contains the components of recorded foreign exchange (gain) loss for the years ended December 31, 2010, 2009 and 2008:

| | Year ended December 31, | | |
|---|---|---|---|
| | 2010 | 2009 | 2008 |
| Unrealized foreign exchange (gain) loss: | | | |
| Subordinated notes and convertible debentures | $ 9,153 | $ 55,508 | $(85,212) |
| Forward contracts and other | (3,542) | (31,138) | 46,009 |
| | 5,611 | 24,370 | (39,203) |
| Realized foreign exchange gains on forward contract settlements | (6,625) | (3,864) | (8,044) |
| | $(1,014) | $ 20,506 | $(47,247) |

The following table illustrates the impact on the fair value of our financial instruments of a 10% hypothetical change in the value of the U.S. dollar compared to the Canadian dollar as of December 31, 2010:

| | |
|---|---|
| Convertible debentures | $ 22,062 |
| Foreign currency forward contracts | $(23,893) |

**Interest Rate Risk**

Changes in interest rates do not have a significant impact on cash payments that are required on our debt instruments as approximately 86% of our debt, including our share of the project-level debt associated with equity investments in affiliates, either bears interest at fixed rates or is financially hedged through the use of interest rate swaps.

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

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

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

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

After considering the impact of interest rate swaps, a hypothetical change in the average interest rate of 100 basis points would change annual interest costs, including interest at equity investments, by approximately $0.9 million.

## ITEM 8. FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA

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

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

None.

## ITEM 9A. CONTROLS AND PROCEDURES

*Conclusion Regarding the Effectiveness of Disclosure Controls and Procedures*

Under the supervision of and with the participation of our management, including our principal executive officer and principal financial officer, we evaluated the effectiveness of the design and operation of our disclosure controls and procedures, as such term is defined in Rules 13a-15(e) and 15d-15(e) of the Securities Exchange Act of 1934, as amended, or the Exchange Act. Based on this evaluation, our principal executive officer and principal financial officer concluded that the disclosure controls and procedures were effective as of the end of the period covered by this Form 10-K.

This Annual Report on Form 10-K does not include a report of management's assessment regarding internal control over financial reporting or an attestation report of the Company's registered public accounting firm due to a transition period established by rules of the Securities and Exchange Commission for newly public companies.

## ITEM 9B. OTHER INFORMATION

None.

## PART III

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

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

### ITEM 11. EXECUTIVE COMPENSATION

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

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

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

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

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

### ITEM 14. PRINCIPAL ACCOUNTING FEES AND SERVICES

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

## PART IV

### ITEM 15. EXHIBITS AND FINANCIAL STATEMENT SCHEDULES

(a)(1) Financial Statements



(a)(2) Financial Statement Schedules

(a)(3) Exhibits

| Exhibit No. | Description |
|---|---|
| 2.1 | Plan of Arrangement of Atlantic Power Corporation, dated as of November 24, 2005 (incorporated by reference to our registration statement on Form 10-12B filed on April 13, 2010) |
| 3.1 | Articles of Continuance of Atlantic Power Corporation, dated as of June 29, 2010 (incorporated by reference to our registration statement on Form 10-12B filed on July 9, 2010) |
| 4.1 | Form of common share certificate (incorporated by reference to our registration statement on Form 10-12B filed on April 13, 2010) |
| 4.2 | Trust Indenture, dated as of October 11, 2006 between Atlantic Power Corporation and Computershare Trust Company of Canada (incorporated by reference to our registration statement on Form 10-12B filed on April 13, 2010) |
| 4.3 | First Supplemental Indenture to the Trust Indenture Providing for the Issue of Convertible Secured Debentures, dated November 27, 2009, between Atlantic Power Corporation and Computershare Trust Company of Canada (incorporated by reference to our registration statement on Form 10-12B filed on April 13, 2010) |
| 4.4 | Trust Indenture Providing for the Issue of Convertible Unsecured Subordinated Debentures, dated as of December 17, 2009, between Atlantic Power Corporation and Computershare Trust Company of Canada (incorporated by reference to our registration statement on Form 10-12B filed on April 13, 2010) |
| 4.5 | Form of First Supplemental Indenture to the Trust Indenture Providing for the Issue of Convertible Unsecured Subordinated Debentures, between Atlantic Power Corporation and Computershare Trust Company of Canada (incorporated by reference to our registration statement on Form S-1/A (File No. 33-138856) filed on September 27, 2010) |
| 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 (incorporated by reference to our registration statement on Form 10-12B filed on April 13, 2010) |
| 10.2 | Employment Agreement, dated as of December 31, 2009 between Atlantic Power Corporation and Barry Welch (incorporated by reference to our registration statement on Form 10-12B filed on April 13, 2010) |
| 10.3 | Employment Agreement, dated as of December 31, 2009 between Atlantic Power Corporation and Patrick Welch (incorporated by reference to our registration statement on Form 10-12B filed on April 13, 2010) |
| 10.4 | Employment Agreement, dated as of December 31, 2009 between Atlantic Power Corporation and Paul Rapisarda (incorporated by reference to our registration statement on Form 10-12B filed on April 13, 2010) |
| 10.5 | Deferred Share Unit Plan, dated as of April 24, 2007 of Atlantic Power Corporation (incorporated by reference to our registration statement on Form 10-12B filed on April 13, 2010) |
| 10.6 | Third Amended and Restated Long-Term Incentive Plan (incorporated by reference to our registration statement on Form 10-12B filed on July 9, 2010) |

| Exhibit No. | Description |
|---|---|
| 16.1 | Letter from KPMG LLP, Chartered Accountants, to the Securities and Exchange Commission, dated August 10, 2010 (incorporated by reference to our Current Report on Form 8-K filed on August 10, 2010) |
| 21.2 | Subsidiaries of Atlantic Power Corporation (incorporated by reference to our registration statement on Form 10-12B filed on April 13, 2010) |
| 31.1* | Certification of Chief Executive Officer pursuant to Rule 13a-14(a)/15d-14(a) under the Securities Exchange Act of 1934 |
| 31.2* | Certification of Chief Financial Officer pursuant to Rule 13a-14(a)/15d-14(a) under the Securities Exchange Act of 1934 |
| 32.1* | Certification of the Chief Executive Officer pursuant to 18 U.S.C. 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002 |
| 32.2* | Certification of the Chief Financial Officer pursuant to 18 U.S.C. 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002 |

* Filed herewith.

## SIGNATURES

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

Date: March 18, 2011

Atlantic Power Corporation

By: /s/ PATRICK J. WELCH

Name: Patrick J. Welch
Title: *Chief Financial Officer*

| Signature | Title | Date |
|---|---|---|
| /s/ BARRY E. WELCH<br>Barry E. Welch | President, Chief Executive Officer and Director (principal executive officer) | March 18, 2011 |
| /s/ PATRICK J. WELCH<br>Patrick J. Welch | Chief Financial Officer (principal financial and accounting officer) | March 18, 2011 |
| /s/ IRVING R. GERSTEIN<br>Irving R. Gerstein | Chairman of the Board | March 18, 2011 |
| /s/ KENNETH M. HARTWICK<br>Kenneth M. Hartwick | Director | March 18, 2011 |
| /s/ R. FOSTER DUNCAN<br>R. Foster Duncan | Director | March 18, 2011 |
| /s/ JOHN A. MCNEIL<br>John A. McNeil | Director | March 18, 2011 |
| /s/ HOLLI NICHOLS<br>Holli Nichols | Director | March 18, 2011 |

| Exhibit No. | Description |
|---|---|
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| Exhibit No. | Description |
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| 21.2 | Subsidiaries of Atlantic Power Corporation (incorporated by reference to our registration statement on Form 10-12B filed on April 13, 2010) |
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| 32.2* | Certification of the Chief Financial Officer pursuant to 18 U.S.C. 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002 |

* Filed herewith.

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

**Report of Independent Registered Public Accounting Firm**

The Board of Directors and Shareholders
Atlantic Power Corporation:

We have audited the accompanying consolidated balance sheet of Atlantic Power Corporation and subsidiaries (the "Company") as of December 31, 2010, and the related consolidated statements of operations, shareholders' equity, and cash flows for the year then ended. In connection with our audit of the consolidated financial statements, we also have audited financial statement schedule "Schedule II Valuation and Qualifying Accounts." These consolidated financial statements and financial statement schedule are the responsibility of the Company's management. Our responsibility is to express an opinion on these consolidated financial statements and financial statement schedule based on our audit.

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

In our opinion, the consolidated financial statements referred to above present fairly, in all material respects, the financial position of Atlantic Power Corporation and subsidiaries as of December 31, 2010, and the results of their operations and their cash flows for the year then ended, in conformity with U.S. generally accepted accounting principles. Also in our opinion, the related financial statement schedule, when considered in relation to the basic consolidated financial statements taken as a whole, presents fairly, in all material respects, the information set forth therein.

/s/ KPMG LLP

New York, New York
March 18, 2011

## Report of Independent Registered Public Accounting Firm

The Board of Directors
Atlantic Power Corporation

We have audited the accompanying consolidated balance sheet of Atlantic Power Corporation as of December 31, 2009 and the related consolidated statements of operations, shareholders' equity and cash flows for each of the years in the two year period ended December 31, 2009. In connection with our audits of the consolidated financial statements, we also have audited financial statement "Schedule II. Valuation and Qualifying Accounts." These consolidated financial statements and financial statement schedule are the responsibility of the Company's management. Our responsibility is to express an opinion on these consolidated financial statements and financial statement schedule based on our audits.

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

As discussed in Note 2 to the consolidated financial statements on January 1, 2009, Atlantic Power Corporation adopted FASB's ASC 805 Business Combinations and on January 1, 2008, Atlantic Power Corporation changed its method of account for fair value measurements in accordance with FASB ASC 820 Fair Value Measurement.

In our opinion the consolidated financial statements referred to above present fairly, in all material respects, the financial position of Atlantic Power Corporation as of December 31, 2009 and the results of its operations and its cash flows for each of the years in the two year period ended December 31, 2009, in conformity with U.S. generally accepted accounting principles. Also in our opinion, the related financial statement schedule, when considered in relation to the basic consolidated financial statements taken as a whole, present fairly, in all material respects, the information set forth therein.

/s/ KPMG LLP

Chartered Accountants, Licensed Public Accountants

Toronto, Canada

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

**ATLANTIC POWER CORPORATION**

**CONSOLIDATED BALANCE SHEETS**

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

| | December 31, 2010 | December 31, 2009 |
|---|---|---|
| **Assets** | | |
| Current assets: | | |
| Cash and cash equivalents | $ 45,497 | $ 49,850 |
| Restricted cash | 15,744 | 14,859 |
| Accounts receivable | 19,362 | 17,480 |
| Note receivable—related party (Note 17) | 22,781 | — |
| Current portion of derivative instruments asset (Notes 11 and 12) | 8,865 | 5,619 |
| Prepayments, supplies, and other | 4,889 | 3,019 |
| Deferred income taxes (Note 13) | — | 17,887 |
| Refundable income taxes (Note 13) | 1,593 | 10,552 |
| Total current assets | 118,731 | 119,266 |
| Property, plant, and equipment, net (Note 5) | 275,421 | 193,822 |
| Transmission system rights (Note 6) | 188,134 | 195,984 |
| Equity investments in unconsolidated affiliates (Note 4) | 294,805 | 259,230 |
| Other intangible assets, net (Note 6) | 88,462 | 71,770 |
| Goodwill (Note 3) | 12,453 | 8,918 |
| Derivative instruments asset (Notes 11 and 12) | 17,884 | 14,289 |
| Other assets | 17,122 | 6,297 |
| Total assets | $1,013,012 | $ 869,576 |
| **Liabilities** | | |
| Current Liabilities: | | |
| Accounts payable and accrued liabilities | $ 20,530 | $ 21,661 |
| Current portion of long-term debt (Note 8) | 21,587 | 18,280 |
| Current portion of derivative instruments liability (Notes 11 and 12) | 10,009 | 6,512 |
| Interest payable on convertible debentures (Note 10) | 3,078 | 800 |
| Dividends payable | 6,154 | 5,242 |
| Other current liabilities | 5 | 752 |
| Total current liabilities | 61,363 | 53,247 |
| Long-term debt (Note 8) | 244,299 | 224,081 |
| Convertible debentures (Note 10) | 220,616 | 139,153 |
| Derivative instruments liability (Notes 11 and 12) | 21,543 | 5,513 |
| Deferred income taxes (Note 13) | 29,439 | 28,619 |
| Other non-current liabilities | 2,376 | 4,846 |
| Commitments and contingencies (Note 19) | | |
| **Equity** | | |
| Common shares, no par value, unlimited authorized shares; 67,118,154 and 60,404,093 issued and outstanding at December 31, 2010 and 2009, respectively | 626,108 | 541,917 |
| Accumulated other comprehensive income (loss) (Note 12) | 255 | (859) |
| Retained deficit | (196,494) | (126,941) |
| Total Atlantic Power Corporation shareholders' equity | 429,869 | 414,117 |
| Noncontrolling interest (Note 3) | 3,507 | — |
| Total equity | 433,376 | 414,117 |
| Total liabilities and equity | $1,013,012 | $ 869,576 |

See accompanying notes to consolidated financial statements.

## ATLANTIC POWER CORPORATION

## CONSOLIDATED STATEMENTS OF OPERATIONS

## (In thousands of U.S. dollars, except per share amounts)

| | Years ended December 31, 2010 | 2009 | 2008 |
|---|---|---|---|
| Project revenue: | | | |
| Energy sales | $ 69,116 | $ 58,953 | $ 64,237 |
| Energy capacity revenue | 93,567 | 88,449 | 77,691 |
| Transmission services | 31,000 | 31,000 | 31,528 |
| Other | 1,573 | 1,115 | 356 |
| | 195,256 | 179,517 | 173,812 |
| Project expenses: | | | |
| Fuel | 65,553 | 59,522 | 55,366 |
| Operations and maintenance | 26,506 | 24,038 | 17,711 |
| Project operator fees and expenses | 4,731 | 4,115 | 3,727 |
| Depreciation and amortization | 40,387 | 41,374 | 29,528 |
| | 137,177 | 129,049 | 106,332 |
| Project other income (expense): | | | |
| Change in fair value of derivative instruments (Notes 11 and 12) | (14,047) | (6,813) | (16,026) |
| Equity in earnings of unconsolidated affiliates (Note 4) | 13,777 | 8,514 | 1,895 |
| Gain on sales of equity investments, net (Note 3) | 1,511 | 13,780 | — |
| Interest expense, net | (17,660) | (18,800) | (17,709) |
| Other income, net | 219 | 1,266 | 5,366 |
| | (16,200) | (2,053) | (26,474) |
| Project income | 41,879 | 48,415 | 41,006 |
| Administrative and other expenses (income): | | | |
| Management fees and administration | 16,149 | 26,028 | 10,012 |
| Interest, net | 11,701 | 55,698 | 43,275 |
| Foreign exchange (gain) loss (Note 12) | (1,014) | 20,506 | (47,247) |
| Other (income) expense, net | (26) | 362 | 425 |
| | 26,810 | 102,594 | 6,465 |
| Income (loss) from operations before income taxes | 15,069 | (54,179) | 34,541 |
| Income tax expense (benefit) (Note 13) | 18,924 | (15,693) | (13,560) |
| Net income (loss) | (3,855) | (38,486) | 48,101 |
| Net loss attributable to noncontrolling interest | (103) | — | — |
| Net income (loss) attributable to Atlantic Power Corporation | $ (3,752) | $ (38,486) | $ 48,101 |
| Net income (loss) per share attributable to Atlantic Power Corporation shareholders: (Note 15) | | | |
| Basic | $ (0.06) | $ (0.63) | $ 0.78 |
| Diluted | $ (0.06) | $ (0.63) | $ 0.73 |

See accompanying notes to consolidated financial statements.

**ATLANTIC POWER CORPORATION**

**CONSOLIDATED STATEMENTS OF SHAREHOLDERS' EQUITY**

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

| | Atlantic Power Corporation Shareholders | | | | | |
|---|---|---|---|---|---|---|
| | Common Stock (Shares) | Common Stock (Amount) | Retained Deficit | Accumulated Other Comprehensive Income | Noncontrolling Interest | Total Shareholders' Equity |
| December 31, 2007 | 61,470 | $216,636 | $(108,832) | $ — | $ — | $107,804 |
| Common shares issued for LTIP | 30 | 127 | — | — | — | 127 |
| Common stock repurchases | (559) | (1,600) | — | — | — | (1,600) |
| Adoption of accounting standard for Fair Value Measurement | — | — | 25,179 | — | — | 25,179 |
| Dividends declared | — | — | (24,849) | — | — | (24,849) |
| Comprehensive Income: | | | | | | |
| Net loss | — | — | 48,101 | — | — | 48,101 |
| Unrealized loss on hedging activities, net of tax of $2,091 | — | — | — | (3,136) | — | (3,136) |
| Net comprehensive income | — | — | — | — | — | 44,965 |
| December 31, 2008 | 60,941 | 215,163 | (60,401) | (3,136) | — | 151,626 |
| Subordinated notes conversion | (114) | 327,691 | — | — | — | 327,691 |
| Common shares issued for LTIP | 59 | 151 | — | — | — | 151 |
| Common stock repurchases | (482) | (1,088) | — | — | — | (1,088) |
| Dividends declared | — | — | (28,054) | — | — | (28,054) |
| Comprehensive Income: | | | | | | |
| Net loss | — | — | (38,486) | — | — | (38,486) |
| Unrealized loss on hedging activities, net of tax of ($1,518) | — | — | — | 2,277 | — | 2,277 |
| Net comprehensive income | — | — | — | — | — | (36,209) |
| December 31, 2009 | 60,404 | 541,917 | (126,941) | (859) | — | 414,117 |
| Convertible debenture conversion | 579 | 7,147 | — | — | — | 7,147 |
| Common shares issuance | 6,029 | 75,267 | — | — | — | 75,267 |
| Common shares issued for LTIP | 106 | 1,325 | — | — | — | 1,325 |
| LTIP amendment (Note 14) | — | 2,952 | — | — | — | 2,952 |
| Piedmont equity costs | | (2,500) | — | — | — | (2,500) |
| Noncontrolling interest | — | — | — | — | 3,507 | 3,507 |
| Dividends declared | — | — | (65,801) | — | — | (65,801) |
| Comprehensive Income: | | | | | | |
| Net loss | — | — | (3,752) | — | — | (3,752) |
| Unrealized gain on hedging activities, net of tax of $743 | — | — | — | 1,114 | — | 1,114 |
| Net comprehensive income | — | — | — | — | — | (2,638) |
| December 31, 2010 | 67,118 | $626,108 | $(196,494) | $ 255 | $3,507 | $433,376 |

See accompanying notes to consolidated financial statements.

## ATLANTIC POWER CORPORATION

## CONSOLIDATED STATEMENTS OF CASH FLOWS

## (In thousands of U.S. dollars)

| | Years ended December 31, 2010 | 2009 | 2008 |
|---|---|---|---|
| Cash flows from operating activities: | | | |
| Net loss | $ (3,855) | $(38,486) | $ 48,101 |
| Adjustments to reconcile to net cash provided by operating activities: | | | |
| Depreciation and amortization | 40,387 | 41,374 | 29,528 |
| Common share conversions recorded in interest expense | — | 4,508 | — |
| Subordinated note redemption premium recorded in interest expense | — | 1,935 | — |
| Long-term incentive plan expense | 4,497 | — | — |
| (Gain) loss on sale of assets | (1,511) | (12,847) | (5,163) |
| Earnings from unconsolidated affiliates | (16,913) | (14,213) | (1,895) |
| Impairment of equity investments | 3,136 | 5,500 | — |
| Distributions from unconsolidated affiliates | 16,843 | 27,884 | 41,031 |
| Unrealized foreign exchange loss (gain) | 5,611 | 24,370 | (39,203) |
| Change in fair value of derivative instruments | 14,047 | 6,813 | 16,026 |
| Change in deferred income taxes | 17,964 | (6,436) | (14,009) |
| Other | (210) | 106 | 27 |
| Change in other operating balances | | | |
| Accounts receivable | 1,729 | 10,520 | 216 |
| Prepayments, refundable income taxes and other assets | 9,311 | (3,454) | 12,229 |
| Accounts payable and accrued liabilities | (6,551) | 2,959 | (20) |
| Other liabilities | 2,468 | (84) | (9,080) |
| Net cash provided by operating activities | 86,953 | 50,449 | 77,788 |
| Cash flows (used in) provided by investing activities: | | | |
| Acquisitions and investments, net of cash acquired | (78,180) | (3,068) | (141,688) |
| Short-term loan to Idaho Wind | (22,781) | — | — |
| Change in restricted cash | 945 | 575 | 6,335 |
| Biomass development costs | (2,286) | — | — |
| Proceeds from sale of assets | 2,000 | 29,467 | 7,889 |
| Purchase of property, plant and equipment | (46,695) | (2,016) | (1,102) |
| Purchases of auction rate securities | — | — | (75,518) |
| Sales of auction rate securities | — | — | 75,518 |
| Net cash (used in) provided by investing activities | (146,997) | 24,958 | (128,566) |
| Cash flows (used in) provided by financing activities: | | | |
| Proceeds from issuance of convertible debenture, net of offering costs | 74,575 | — | — |
| Proceeds from issuance of equity, net of offering costs | 72,767 | — | — |
| Deferred financing costs | (7,941) | — | |
| Repayment of project-level debt | (18,882) | (12,744) | (22,275) |
| Proceeds from revolving credit facility borrowings | 20,000 | — | 55,000 |
| Repayments of revolving credit facility borrowings | (20,000) | (55,000) | — |
| Dividends paid | (65,028) | (24,955) | (24,612) |
| Equity contribution from noncontrolling interest | 200 | — | — |
| Proceeds from issuance of project level debt | — | 78,330 | 35,000 |
| Redemption of IPSs under normal course issuer bid | — | (3,369) | (1,612) |
| Redemption of subordinated notes | — | (40,638) | (3,064) |
| Costs associated with common share conversion | — | (4,508) | — |
| Net cash provided by (used in) financing activities | 55,691 | (62,884) | 38,437 |
| Net (decrease) increase in cash and cash equivalents | (4,353) | 12,523 | (12,341) |
| Cash and cash equivalents at beginning of period | 49,850 | 37,327 | 49,668 |
| Cash and cash equivalents at end of period | $ 45,497 | $ 49,850 | $ 37,327 |
| Supplemental cash flow information | | | |
| Interest paid | $ 26,687 | $ 69,186 | $ 72,129 |
| Income taxes paid (refunded), net | $ (8,000) | $ (216) | $ 2,418 |

See accompanying notes to consolidated financial statements.

## ATLANTIC POWER CORPORATION
## NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

### 1. Nature of Business

***Overview***

Atlantic Power Corporation ("Atlantic Power") is a corporation established under the laws of the Province of Ontario, Canada on June 18, 2004 and continued to the Province of British Columbia on July 8, 2005. We issued income participating securities ("IPSs") for cash pursuant to an initial public offering on the Toronto Stock Exchange, or the TSX, on November 18, 2004. Each IPS was comprised of one common share and Cdn$5.767 principal value of 11% subordinated notes due 2016. On November 27, 2009 our shareholders approved a conversion from the IPS structure to a traditional common share structure. Each IPS has been exchanged for one new common share and each old common share that did not form a part of an IPS was exchanged for approximately 0.44 of a new common share. Our shares trade on the TSX under the symbol "ATP" and began trading on the New York Stock Exchange, or the NYSE, under the symbol "AT" on July 23, 2010.

We own interests in power projects for 13 operational power generation projects across ten states, one biomass project under construction in Georgia, a 500 kilovolt 84-mile electric transmission line located in California and a number of development projects. Our power generation projects in operation have an aggregate gross electric generation capacity of approximately 1,962 megawatts (or "MW"), in which our ownership interest is approximately 878 MW. Five of our projects are wholly-owned subsidiaries: Lake Cogen, Ltd., Pasco Cogen, Ltd., Auburndale Power Partners, L.P., Cadillac Renewable Energy, LLC and Atlantic Path 15, LLC. The consolidated financial statements have been prepared in accordance with United States generally accepted accounting principles ("GAAP") with a reconciliation to Canadian GAAP in Note 22. The Canadian securities legislation allows issuers that are required to file reports with the Securities and Exchange Commission ("SEC") in the United States to file financial statements under United States GAAP to meet their continuous disclosure obligations in Canada. Prior to 2010, we prepared our consolidated financial statements in accordance with Canadian GAAP.

Our registered office is located at 355 Burrard Street, Suite 1900, Vancouver, British Columbia V6C 2G8 and our headquarters is located at 200 Clarendon Street, Floor 25, Boston, Massachusetts, USA 02116. The telephone number is (617) 977-2400. The address of our website is www.atlanticpower.com. Our recent U.S. and Canadian securities filings are available through our website.

### 2. Summary of significant accounting policies

(a) Principles of consolidation and basis of presentation:

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

We apply the standard that requires consolidation of variable interest entities ("VIEs"), for which we are the primary beneficiary. The guidance requires a variable interest holder to consolidate a VIE if that party has both the power to direct the activities that most significantly impact the entities' economic performance, as well as either the obligation to absorb losses or the right to receive benefits

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

that could potentially be significant to the VIE. We have determined that our investments are not VIEs by evaluating their design and capital structure. Accordingly, we use the equity method of accounting for all of our investments in which we do not have an economic controlling interest. We eliminate all intercompany accounts and transactions in consolidation.

(b) Use of estimates:

The preparation of financial statements requires us to make estimates and assumptions that affect the reported amounts of assets and liabilities and disclosure of contingent assets and liabilities at the date of the financial statements and the reported amounts of revenue and expenses during the year. Actual results could differ from those estimates. During the periods presented, we have made a number of estimates and valuation assumptions, including the fair values of acquired assets, the useful lives and recoverability of property, plant and equipment and power purchase agreements (“PPAs”), the recoverability of equity investments, the recoverability of deferred tax assets, tax provisions, the valuation of shares associated with our Long-Term Incentive Plan and the fair value of financial instruments and derivatives. In addition, estimates are used to test long-lived assets and goodwill for impairment and to determine the fair value of impaired assets. These estimates and valuation assumptions are based on present conditions and our planned course of action, as well as assumptions about future business and economic conditions. As better information becomes available or actual amounts are determinable, the recorded estimates are revised. Should the underlying valuation assumptions and estimates change, the recorded amounts could change by a material amount.

(c) Regulatory accounting:

Path 15 accounts for certain income and expense items in accordance with a standard where certain costs are deferred, which would otherwise be charged to expense, as regulatory assets based on Path 15’s ability to recover these costs in future rates.

(d) Revenue:

We recognize energy sales revenue on a gross basis when electricity and steam are delivered under the terms of the related contracts. Revenue associated with capacity payments under the PPAs are recognized as the lesser of (1) the amount billable under the PPA or (2) an amount determined by the kilowatt hours made available during the period multiplied by the estimated average revenue per kilowatt hour over the term of the PPA.

Transmission services revenue is recognized as transmission services are provided. The annual revenue requirement for transmission services is regulated by the Federal Energy Regulatory Commission (“FERC”) and is established through a rate-making process that occurs every three years. When actual cash receipts from transmission services revenue are different than the regulated revenue requirement because of timing differences, the over or under collections are deferred until the timing differences reverse in future periods.

(e) Cash and cash equivalents:

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

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

(f) Restricted cash:

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

(g) Use of fair value:

We utilize a fair value hierarchy that gives the highest priority to quoted prices in active markets and is applicable to fair value measurements of derivative contracts and other instruments that are subject to mark-to-market accounting. Refer to Note 11 for more information.

(h) Derivative financial instruments:

We use derivative financial instruments in the form of interest rate swaps and foreign exchange forward contracts to manage our current and anticipated exposure to fluctuations in interest rates and foreign currency exchange rates. We have also entered into natural gas supply contracts and natural gas forwards or swaps to minimize the effects of the price volatility of natural gas, which is a major production cost. We do not enter into derivative financial instruments for trading or speculative purposes; however, not all derivatives qualify for hedge accounting.

Derivative financial instruments not designated as a hedge are measured at fair value with changes in fair value recorded in the consolidated statements of operations.

The following table summarizes derivative financial instruments that are not designated as hedges for accounting purposes and the accounting treatment in the consolidated statements of operations of the changes in fair value and cash settlements of such derivative financial instrument:

| Derivative financial instrument | Classification of changes in fair value | Classification of cash settlements |
|---|---|---|
| Foreign currency forward contracts | Foreign exchange loss (gain) | Foreign exchange loss (gain) |
| Lake natural gas swaps | Change in fair value of derivative instruments | Fuel expense |
| Auburndale natural gas swaps | Change in fair value of derivative instruments | Fuel expense |
| Orlando natural gas swaps | Change in fair value of derivative instruments | Fuel expense |
| Interest rate swaps | Change in fair value of derivative instruments | Interest expense |

Certain derivative instruments qualify for a scope exception to fair value accounting because they are considered normal purchases or normal sales. This exception applies when we have the ability to and it is probable that we will deliver or take delivery of the underlying physical commodity. Derivatives that are considered to be normal purchases and normal sales are exempt from derivative accounting treatment and are recorded as executory contracts.

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

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

(i) Property, plant and equipment:

Property, plant and equipment are stated at cost, net of accumulated depreciation. Depreciation is provided on a straight-line basis over the estimated useful life of the related asset. As major maintenance occurs and parts are replaced on the plant's combustion and steam turbines, maintenance costs are either expensed or transferred to property, plant and equipment if the maintenance extends the useful lives of the major parts. These costs are depreciated over the parts' estimated useful lives, which is generally three to six years, depending on the nature of maintenance activity performed.

(j) Transmission system rights:

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

(k) Asset retirement obligations:

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

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

Long-lived assets, such as property, plant and equipment, transmission system rights and other intangible assets subject to depreciation and amortization, are reviewed for impairment whenever events or changes in circumstances indicate that the carrying amount of an asset may not be recoverable. Recoverability of assets to be held and used is measured by a comparison of the carrying amount of an asset to estimated undiscounted future cash flows expected to be generated by the asset. If the carrying amount of an asset exceeds its estimated future cash flows, an impairment charge is recognized in the amount by which the carrying amount of the asset exceeds its fair value.

Investments in and the operating results of 50%-or-less owned entities not required to be consolidated are included in the consolidated financial statements on the basis of the equity method of accounting. We review our investments in such unconsolidated entities for impairment whenever events or changes in business circumstances indicate that the carrying amount of the investments may not be fully recoverable. Evidence of a loss in value that is other than temporary might include the absence of an ability to recover the carrying amount of the investment, the inability of the investee to sustain an earnings capacity which would justify the carrying amount of the investment, failure of cash flow coverage ratio tests included in project-level non-recourse debt or, where applicable, estimated sales proceeds which are insufficient to recover the carrying amount of the investment. Our assessment as to whether any decline in value is other than temporary is based on our ability and intent to hold the investment and whether evidence indicating the carrying value of the investment is recoverable within a

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

reasonable period of time outweighs evidence to the contrary. We generally consider our investments in our equity method investees to be strategic long-term investments. Therefore, we complete our assessments with a long-term view. If the fair value of the investment is determined to be less than the carrying value and the decline in value is considered to be other than temporary, the asset is written down to its fair value.

(m) Distributions from equity method investments:

We make investments in entities that own power producing assets with the objective of generating accretive cash flow that is available to be distributed to our shareholders. The cash flows that are distributed to us from these unconsolidated affiliates are directly related to the operations of the affiliates' power producing assets and are classified as cash flows from operating activities in the consolidated statements of cash flows.

We record the return of our investments in equity investees as cash flows from investing activities. Cash flows from equity investees are considered a return of capital when distributions are generated from proceeds of either the sale of our investment in its entirety or a sale by the investee of all or a portion of its capital assets.

(n) Goodwill:

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

Goodwill is not amortized and is tested for impairment, annually in the fourth quarter, or more frequently if events or changes in circumstances indicate that the asset might be impaired. The impairment test is carried out in two steps. In the first step, the carrying amount of the reporting unit is compared with its fair value. When the fair value of a reporting unit exceeds its carrying amount, goodwill of the reporting unit is considered not to be impaired and the second step of the impairment test is unnecessary.

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

(o) Other intangible assets:

Other intangible assets include PPAs and fuel supply agreements at our projects.

PPAs are valued at the time of acquisition based on the contract prices under the PPAs compared to projected market prices. Fuel supply agreements are valued at the time of acquisition based on the contract prices under the fuel supply agreement compared to projected market prices. The balances are

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

presented net of accumulated amortization in the consolidated balance sheets. Amortization is recorded on a straight-line basis over the remaining term of the agreement.

(p) Income taxes:

Income tax expense includes the current tax obligation or benefit and change in deferred income tax asset or liability for the period. We use the asset and liability method of accounting for deferred income taxes and record deferred income taxes for all significant temporary differences. Income tax benefits associated with uncertain tax positions are recognized when we determine that it is more-likely-than-not that the tax position will be ultimately sustained. Refer to Note 13 for more information.

(q) Foreign currency translation:

Our functional currency and reporting currency is the United States dollar. The functional currency of our subsidiaries and other investments is the United States dollar. Monetary assets and liabilities denominated in Canadian dollars are translated into United States dollars using the rate of exchange in effect at the end of the period. All transactions denominated in Canadian dollars are translated into United States dollars at average exchange rates.

(r) Long-term incentive plan:

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

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

Compensation expense related to awards granted to participants in the LTIP is recorded over the vesting period based on the estimated fair value of the award on the grant date for notional units accounted for as equity awards and the fair value of the award at each balance sheet date for notional units accounted for as liability awards. Fair value of the awards granted prior to the 2010 amendment is determined by projecting the total number of notional units that will vest in future periods, including dividends received on notional units during the vesting period, and applying the current market price per share to the projected number of notional units that will vest. The fair value of awards granted for the 2010 performance period with market vesting conditions is based upon a Monte Carlo simulation model on their grant date. The aggregate number of shares which may be issued from treasury under

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

the LTIP is limited to one million. Unvested notional units are recorded as either a liability or equity award based on management's intended method of redeeming the notional units when they vest.

(s) Deferred financing costs:

Deferred financing costs represent costs to obtain long-term financing and are amortized using the effective interest method over the term of the related debt which range from five to 28 years. The net carrying amount of deferred financing costs recorded in other assets on the consolidated balance sheets was $16.7 million and $5.5 million at December 31, 2010 and 2009, respectively. Amortization expense for the years ended December 31, 2010, 2009 and 2008 was $1.2 million, $14.6 million, and $1.1 million, respectively.

(t) Concentration of credit risk:

The financial instruments that potentially expose us to credit risk consist primarily of cash and cash equivalents, restricted cash, derivative instruments and accounts receivable. Cash and restricted cash are held by major financial institutions that are also counterparties to our derivative instruments. We have long-term agreements to sell electricity, gas and steam to public utilities and corporations. We have exposure to trends within the energy industry, including declines in the creditworthiness of our customers. We do not normally require collateral or other security to support energy-related accounts receivable. We do not believe there is significant credit risk associated with accounts receivable due to payment history. See Note 16, *Segment and related information*, for a further discussion of customer concentrations.

(u) Segments:

We have six reportable segments: Auburndale, Lake, Pasco, Chambers, Path 15 and Other Project Assets. Each of our projects is an operating segment. Based on similar economic and other characteristics, we aggregate several of the projects into the Other Project Assets reportable segment.

(v) Recently issued accounting standards:

*Adopted*

In December 2010, the FASB issued changes to the disclosure of pro forma information for business combinations. These changes clarify that if a public entity presents comparative financial statements, the entity should disclose revenue and earnings of the combined entity as though the business combination that occurred during the current year had occurred as of the beginning of the comparable prior annual reporting period only. Also, the existing supplemental pro forma disclosures were expanded to include a description of the nature and amount of material, nonrecurring pro forma adjustments directly attributable to the business combination included in the reported pro forma revenue and earnings. We adopted these changes beginning January 1, 2011. Upon adoption, we determined these changes did not impact the consolidated financial statements.

In December 2010, the FASB issued changes to the testing of goodwill for impairment. These changes require an entity to perform all steps in the test for a reporting unit whose carrying value is zero or negative if it is more likely than not (more than 50%) that a goodwill impairment exists based on qualitative factors, resulting in the elimination of an entity's ability to assert that such a reporting unit's goodwill is not impaired and additional testing is not necessary despite the existence of

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

qualitative factors that indicate otherwise. We adopted these changes beginning January 1, 2011. Based on the most recent impairment review of our goodwill (2010 fourth quarter), we determined these changes did not impact the consolidated financial statements.

On January 1, 2010, we adopted changes issued by the Financial Accounting Standards Board (FASB) to accounting for variable interest entities. These changes require an enterprise to perform an analysis to determine whether the enterprise's variable interest or interests give it a controlling financial interest in a variable interest entity; to require ongoing reassessments of whether an enterprise is the primary beneficiary of a variable interest entity; to eliminate the solely quantitative approach previously required for determining the primary beneficiary of a variable interest entity; to add an additional reconsideration event for determining whether an entity is a variable interest entity when any changes in facts and circumstances occur such that holders of the equity investment at risk, as a group, lose the power from voting rights or similar rights of those investments to direct the activities of the entity that most significantly impact the entity's economic performance; and to require enhanced disclosures that will provide users of financial statements with more transparent information about an enterprise's involvement in a variable interest entity. The adoption of these changes had no impact on the consolidated financial statements.

On January 1, 2010, we adopted changes issued by the FASB to accounting for transfers of financial assets. These changes remove the concept of a qualifying special-purpose entity and remove the exception from the application of variable interest accounting to variable interest entities that are qualifying special-purpose entities; limit the circumstances in which a transferor derecognizes a portion or component of a financial asset; define a participating interest; require a transferor to recognize and initially measure at fair value all assets obtained and liabilities incurred as a result of a transfer accounted for as a sale; and require enhanced disclosure. The adoption of these changes had no impact on the consolidated financial statements.

Effective January 1, 2010, we adopted changes issued by the FASB on January 6, 2010 for a scope clarification to the FASB's previously-issued guidance on accounting for noncontrolling interests in consolidated financial statements. These changes clarify the accounting and reporting guidance for noncontrolling interests and changes in ownership interests of a consolidated subsidiary. An entity is required to deconsolidate a subsidiary when the entity ceases to have a controlling financial interest in the subsidiary. Upon deconsolidation of a subsidiary, an entity recognizes a gain or loss on the transaction and measures any retained investment in the subsidiary at fair value. The gain or loss includes any gain or loss associated with the difference between the fair value of the retained investment in the subsidiary and its carrying amount at the date the subsidiary is deconsolidated. In contrast, an entity is required to account for a decrease in its ownership interest of a subsidiary that does not result in a change of control of the subsidiary as an equity transaction. The adoption of these changes had no impact on the consolidated financial statements.

Effective January 1, 2010, we adopted changes issued by the FASB on January 21, 2010 to disclosure requirements for fair value measurements. Specifically, the changes require a reporting entity to disclose separately the amounts of significant transfers in and out of Level 1 and Level 2 fair value measurements and describe the reasons for the transfers. The changes also clarify existing disclosure requirements related to how assets and liabilities should be grouped by class and valuation techniques used for recurring and nonrecurring fair value measurements. The adoption of these changes had no impact on the consolidated financial statements.

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

Effective January 1, 2010, we adopted changes issued by the FASB on February 24, 2010 to accounting for and disclosure of events that occur after the balance sheet date but before financial statements are issued or available to be issued, otherwise known as "subsequent events." Specifically, these changes clarify that an entity that is required to file or furnish its financial statements with the Securities and Exchange Commission is not required to disclose the date through which subsequent events have been evaluated. The adoption of these changes had no impact on the consolidated financial statements.

On July 1, 2010, we adopted changes to existing accounting requirements for embedded credit derivatives. Specifically, the changes clarify the scope exception regarding when embedded credit derivative features are not considered embedded derivatives subject to potential bifurcation and separate accounting. The adoption of these changes had no impact on the consolidated financial statements.

*Issued*

In October 2009, the FASB issued changes to revenue recognition for multiple-deliverable arrangements. These changes require separation of consideration received in such arrangements by establishing a selling price hierarchy (not the same as fair value) for determining the selling price of a deliverable, which will be based on available information in the following order: vendor-specific objective evidence, third-party evidence, or estimated selling price; eliminate the residual method of allocation and require that the consideration be allocated at the inception of the arrangement to all deliverables using the relative selling price method, which allocates any discount in the arrangement to each deliverable on the basis of each deliverable's selling price; require that a vendor determine its best estimate of selling price in a manner that is consistent with that used to determine the price to sell the deliverable on a standalone basis; and expand the disclosures related to multiple-deliverable revenue arrangements. These changes become effective on January 1, 2011. We have determined that the adoption of these changes will not have an impact on the consolidated financial statements, as our projects do not currently have any such arrangements with their customers.

In January 2010, the FASB issued changes to disclosure requirements for fair value measurements. Specifically, the changes require a reporting entity to disclose, in the reconciliation of fair value measurements using significant unobservable inputs (Level 3), separate information about purchases, sales, issuances, and settlements (that is, on a gross basis rather than as one net number) of these Level 3 financial instruments. These changes become effective beginning January 1, 2011. Other than the additional disclosure requirements, we have determined these changes will not have an impact on the consolidated financial statements.

In April 2010, the FASB issued changes to the classification of certain employee share-based payment awards. These changes clarify that there is not an indication of a condition that is other than market, performance, or service if an employee share-based payment award's exercise price is denominated in the currency of a market in which a substantial portion of the entity's equity securities trade and differs from the functional currency of the employer entity or payroll currency of the employee. An employee share-based payment award is required to be classified as a liability if the award does not contain a market, performance, or service condition. These changes become effective on January 1, 2011. We have determined these changes will not have an impact on the consolidated financial statements.

**3. Acquisitions and divestments**

(a) Cadillac

On December 21, 2010, we acquired 100% of Cadillac Renewable Energy, LLC, which owns and operates a 39.6 MW wood fired facility in Cadillac, Michigan. The purchase price was funded by $37.0 million using a portion of the cash raised in the public equity and convertible debenture offerings in October 2010 and the assumption of $43.1 million of project-level debt. The cash payment for the acquisition was allocated to the net assets acquired based on our preliminary estimates of fair value.

Total cash paid for the acquisition, less cash acquired in December 2010 was $35.1 million.

The allocation of the purchase price to the net assets acquired is as follows:

| | |
|---|---|
| Recognized amounts of identifiable assets acquired and liabilities assumed: | |
| Working capital | $ 5,643 |
| Property, plant and equipment | 42,101 |
| Power purchase agreements | 36,420 |
| Interest rate swap derivative | (4,038) |
| Project-level debt | (43,131) |
| Total purchase price | 36,995 |
| Less cash acquired | (1,870) |
| Cash paid, net of cash acquired | $ 35,125 |

(b) Topsham

During the three months ended December 31, 2010, we reviewed the recoverability of our 50.0% equity investment in the Topsham project. The review was undertaken as a result of the PPA expiring on December 31, 2011 and our view about the long-term economic viability of the plant upon this expiration.

Based on this review we determined that the carrying value of the Topsham project was impaired and recorded a pre-tax long-lived asset impairment of $2.0 million during 2010. The Topsham project is accounted for under the equity method of accounting and the impairment charge is included in equity in earnings of unconsolidated affiliates in the consolidated statements of operations.

On February 28, 2011, we entered into a purchase and sale agreement with a third party for the purchase of our lessor interest in the project. Closing of the transaction is expected to occur in the second quarter of 2011.

(c) Rumford

During the three months ended September 30, 2009, we reviewed the recoverability of our 23.5% equity investment in the Rumford project. The review was undertaken as a result of not receiving distributions from the Project through the first nine months of 2009 and our view about the long-term economic viability of the plant upon expiration of the project's PPA on December 31, 2009.

Based on this review, we determined that the carrying value of the Rumford project was impaired and recorded a pre-tax long-lived asset impairment of $5.5 million during 2009. The Rumford project is

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

accounted for under the equity method of accounting and the impairment charge is included in equity in earnings of unconsolidated affiliates in the consolidated statements of operations.

In the fourth quarter of 2009, Atlantic Power and the other limited partners in the Rumford project settled a dispute with the general partner related to the general partner's failure to pay distributions to the limited partners in 2009. Under the terms of the settlement, we received $2.9 million in distributions from Rumford in the fourth quarter of 2009. In addition, the general partner had agreed to purchase the interests of all the limited partners in June 2010. In November 2010 we received our share of the proceeds of $2.0 million and recognized a gain on sale of investment of $1.5 million.

(d) Piedmont

On October 21, 2010 we completed the closing of non-recourse, project-level bank financing for our Piedmont Green Power project ("Piedmont"). The terms of the financing include an $82.0 million construction and term loan and a $51.0 million bridge loan for approximately 95% of the stimulus grant expected to be received from the U.S. Treasury 60 days after the start of commercial operations. In addition, we will make an equity contribution of approximately $75.0 million for substantially all of the equity interest in the project. As of December 31, 2010 we have contributed $58.7 million and construction has commenced.

Piedmont is a 53.5 MW biomass plant located in Barnesville, Georgia, approximately 70 miles south of Atlanta. The Project was developed and will be managed by Rollcast Energy, Inc., a biomass developer in which we own a 60% interest.

(e) Idaho Wind

On July 2, 2010, we acquired a 27.6% equity interest in Idaho Wind Partners 1, LLC ("Idaho Wind") for $38.9 million and approximately $3.1 million in transaction costs. Idaho Wind recently commenced construction of a 183 MW wind power project located near Twin Falls, Idaho, which is expected to be completed in early 2011. Idaho Wind has 20-year PPAs with Idaho Power Company. Our investment in Idaho Wind was funded with cash on hand and a $20.0 million borrowing under our senior credit facility, which was repaid in October 2010 with a portion of the proceeds from our public offering (see Note 10 and Note 18). Idaho Wind is accounted for under the equity method of accounting.

During 2010, we made a short-term $22.8 million loan to Idaho Wind to provide temporary funding for construction of the project until a portion of the project-level construction financing is completed. Member loans will be paid down with a combination of excess proceeds from the federal stimulus cash grant after repaying the cash grant facility, funds from a third closing for additional debt, and project cash flow. The federal stimulus grant is expected in the second quarter of 2011 and a third closing is expected by the end of the year. The outstanding loans bear interest at a prime rate plus 10% (13.25% as December 31, 2010). As of March 18, 2011, $5.1 million of the loan has been repaid.

(f) Rollcast

On March 31, 2009, we acquired a 40% equity interest in Rollcast Energy, Inc., a North Carolina Corporation for $3.0 million in cash. On March 1, 2010, we paid $1.2 million in cash for an additional

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

15% of the shares of Rollcast, increasing our interest from 40% to 55% and providing us control of Rollcast. We consolidated Rollcast as of that date. We previously accounted for our 40% interest in Rollcast as an equity method investment. On April 28, 2010, we paid an additional $0.8 million to increase our ownership interest in Rollcast to 60%.

Rollcast is a developer of biomass power plants in the southeastern U.S. with several projects in various stages of development. The investment in Rollcast gives us the option but not the obligation to invest equity in Rollcast's biomass power plants.

The following table summarizes the consideration transferred to acquire Rollcast and the preliminary estimated amounts of identifiable assets acquired and liabilities assumed at the March 1, 2010 acquisition date, as well as the fair value of the noncontrolling interest in Rollcast at the acquisition date:

| | |
|---|---|
| Fair value of consideration transferred: | |
| Cash | $1,200 |
| Other items to be allocated to identifiable assets acquired and liabilities assumed: | |
| Fair value of our investment in Rollcast at the acquisition date | 2,758 |
| Fair value of noncontrolling interest in Rollcast | 3,410 |
| Gain recognized on the step acquisition | 211 |
| Total | $7,579 |
| Recognized amounts of identifiable assets acquired and liabilities assumed: | |
| Cash | $1,524 |
| Property, plant and equipment | 130 |
| Prepaid expenses and other assets | 133 |
| Capitalized development costs | 2,705 |
| Trade and other payables | (448) |
| Total identifiable net assets | 4,044 |
| Goodwill | 3,535 |
| | $7,579 |

As a result of obtaining control over Rollcast, our previously held 40% interest was remeasured to fair value, resulting in a gain of $0.2 million. This has been recognized in other income (expense) in the consolidated statements of operations.

The fair value of the noncontrolling interest of $3.4 million in Rollcast was estimated by applying an income approach using the discounted cash flow method. This fair value measurement is based on significant inputs not observable in the market and thus represents a Level 3 fair value measurement. The fair value estimate utilized an assumed discount rate of 9.4% which is composed of a risk-free rate and an equity risk premium determined by the capital asset pricing of companies deemed to be similar to Rollcast. The estimate assumed that no fair value adjustments are required because of the lack of control or lack of marketability that market participants would consider when estimating the fair value of the noncontrolling interest in Rollcast.

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

The goodwill is attributable to the value of future biomass power plant development opportunities. It is not expected to be deductible for tax purposes. All of the $3.5 million of goodwill was assigned to the Other Project Assets segment.

(g) Stockton

On November 30, 2009, we sold our 50% interest in the assets of Stockton Cogen Company LP for a nominal cash payment. Stockton is a 55 MW coal/biomass cogeneration facility located in Stockton, California. During the year ended December 31, 2009, we recorded a loss on the sale of $2.0 million. The loss on sale was recorded in gain (loss) on sales of equity investments in the consolidated statements of operations.

(h) Mid-Georgia

On November 24, 2009, we sold our 50% interest in the assets of Mid-Georgia Cogen LP for $29.1 million. Mid-Georgia is a 308 MW dual-fueled, combined-cycle cogeneration plant located in Kathleen, Georgia. We recorded a gain on sale of asset of $15.8 million. The gain on sale was recorded in gain (loss) on sales of equity investments in the consolidated statements of operations.

(i) Onondaga Renewables

In the first quarter of 2009, we transferred our remaining net assets of Onondaga Cogeneration Limited Partnership at net book value, into a 50% owned joint venture, Onondaga Renewables, LLC, which is redeveloping the project into a 35-40 MW biomass power plant. Our investment in Onondaga Renewables is accounted for under the equity method of accounting.

(j) Auburndale

On November 21, 2008, we acquired 100% of Auburndale Power Partners, L.P., which owns and operates a 155 MW natural gas-fired combined cycle cogeneration facility located in Polk County, Florida. The purchase price was funded by cash on hand, a borrowing under our credit facility and $35 million of acquisition debt. The cash payment for the acquisition, including acquisition costs, was allocated to the net assets acquired based on our estimate of the fair value.

Total cash paid for the acquisition, less cash acquired, during 2008 was $141.7 million. In 2009, we received a working capital adjustment from the sellers in the amount of $1.8 million, resulting in a final purchase price of $139.9 million.

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

The allocation of the purchase price to the net assets acquired is as follows:

| | |
|---|---|
| Working capital | $ 11,589 |
| Property, plant and equipment | 56,301 |
| Power purchase agreements | 45,980 |
| Fuel supply agreements | 33,846 |
| Other long-term assets | 663 |
| Total purchase price | 148,379 |
| Less cash acquired | (8,471) |
| Cash paid, net of cash acquired | $139,908 |

**4. Equity method investments**

During the three months ended December 31, 2010, we reviewed the recoverability of our 50.0% equity investment in the Badger Creek project. The review was undertaken as a result of the project's recent discussions with utilities in California, the current status of the regulatory proceedings related to contract pricing for qualified facilities in California and recent comparable market transactions in the region.

Based on this review we determined that the carrying value of the Badger Creek project was impaired and recorded a pre-tax long-lived asset impairment of $1.2 million during 2010. The Badger Creek project is accounted for under the equity method of accounting and the impairment charge is included in equity in earnings of unconsolidated affiliates in the consolidated statements of operations.

The following tables summarize our equity method investments:

| Entity name | Percentage of Ownership as of December 31, 2010 | Carrying value as of December 31, 2010 | Carrying value as of December 31, 2009 |
|---|---|---|---|
| Rollcast Energy, Inc.* | 60.0% | $ — | $ 2,801 |
| Badger Creek Limited | 50.0% | 7,839 | 9,949 |
| Orlando Cogen, LP | 50.0% | 31,543 | 36,387 |
| Topsham Hydro Assets | 50.0% | 8,500 | 10,825 |
| Onondaga Renewables, LLC | 50.0% | 1,761 | 1,757 |
| Koma Kulshan Associates | 49.8% | 6,491 | 7,003 |
| Chambers Cogen, LP | 40.0% | 139,855 | 129,501 |
| Delta-Person, LP | 40.0% | — | — |
| Idaho Wind Partners 1, LLC | 27.6% | 41,376 | — |
| Selkirk Cogen Partners, LP | 18.5% | 53,575 | 57,030 |
| Gregory Power Partners, LP | 17.1% | 3,662 | 2,931 |
| Other | — | 203 | 1,046 |
| Total | | $294,805 | $259,230 |

* Rollcast was consolidated in the first quarter of 2010.

**4. Equity method investments (Continued)**

Equity in earnings (loss) of unconsolidated affiliates was as follows:

| Entity name | Year Ended December 31, 2010 | 2009 | 2008 |
|---|---|---|---|
| Rollcast Energy, Inc. | $ (66) | $ (267) | $ — |
| Badger Creek Limited | 749 | 1,948 | 2,477 |
| Orlando Cogen, LP | 2,031 | 3,152 | 2,920 |
| Topsham Hydro Assets | (436) | 1,506 | 2,064 |
| Onondaga Renewables, LLC | (320) | (600) | — |
| Koma Kulshan Associates | 452 | 458 | 580 |
| Chambers Cogen, LP | 13,144 | 6,599 | 16,250 |
| Delta-Person, LP | — | (644) | (1,076) |
| Idaho Wind Partners 1, LLC | (126) | — | — |
| Rumford Cogeneration, LP | (359) | (1,904) | 2,922 |
| Selkirk Cogen Partners, LP | (3,454) | (280) | (6,958) |
| Gregory Power Partners, LP | 2,162 | 1,791 | 4,621 |
| Mid-Georgia Cogen, LP | — | (2,686) | (2,068) |
| Other | — | (559) | (19,837) |
| Total | 13,777 | 8,514 | 1,895 |
| Distributions from equity method investments | (16,843) | (27,884) | (41,031) |
| Equity in earnings (loss) of unconsolidated affiliates, net of distributions | $ (3,066) | $(19,370) | $(39,136) |

**4. Equity method investments (Continued)**

The following summarizes the balance sheets at December 31, 2010, 2009 and 2008, and operating results for each of the years ended December 31, 2010, 2009 and 2008, respectively, for our proportional ownership interest in equity method investments:

| | 2010 | 2009 | 2008 |
|---|---|---|---|
| **Assets** | | | |
| Current assets | | | |
| Chambers | $ 11,391 | $ 10,356 | $ 14,418 |
| Mid-Georgia | — | — | 13,967 |
| Badger Creek | 2,714 | 2,567 | 3,175 |
| Gregory | 3,063 | 11,358 | 5,766 |
| Orlando | 6,965 | 6,725 | 9,366 |
| Selkirk | 11,782 | 9,431 | 11,722 |
| Other | 7,563 | 2,043 | 8,489 |
| Non-Current assets | | | |
| Chambers | 253,388 | 259,989 | 266,686 |
| Mid-Georgia | — | — | 53,706 |
| Badger Creek | 6,645 | 9,177 | 10,481 |
| Gregory | 19,490 | 12,351 | 21,323 |
| Orlando | 29,419 | 34,975 | 40,026 |
| Selkirk | 65,036 | 78,748 | 89,110 |
| Other | 128,763 | 34,631 | 37,229 |
| | $546,219 | $472,351 | $585,464 |
| **Liabilities** | | | |
| Current liabilities | | | |
| Chambers | $ 15,914 | $ 16,898 | $ 16,692 |
| Mid-Georgia | — | — | 3,938 |
| Badger Creek | 1,520 | 1,795 | 1,980 |
| Gregory | 3,421 | 4,118 | 3,525 |
| Orlando | 4,841 | 5,313 | 3,482 |
| Selkirk | 17,371 | 13,495 | 13,727 |
| Other | 76,910 | 1,704 | 3,443 |
| Non-Current liabilities | | | |
| Chambers | 109,010 | 123,946 | 140,381 |
| Mid-Georgia | — | — | 48,394 |
| Badger Creek | — | — | — |
| Gregory | 15,470 | 16,660 | 20,183 |
| Orlando | — | — | — |
| Selkirk | 5,872 | 17,654 | 26,798 |
| Other | 1,085 | 11,538 | 15,146 |
| | $251,414 | $213,121 | $297,689 |

**4. Equity method investments (Continued)**

| | 2010 | 2009 | 2008 |
|---|---|---|---|
| **Operating results** | | | |
| Revenue | | | |
| Chambers | $ 55,469 | $ 50,745 | $ 68,893 |
| Mid-Georgia | — | 6,521 | 14,992 |
| Badger Creek | 13,485 | 12,861 | 20,502 |
| Gregory | 31,291 | 28,477 | 57,434 |
| Orlando | 42,062 | 41,911 | 34,372 |
| Selkirk | 51,915 | 47,577 | 71,641 |
| Other | 3,501 | 23,327 | 27,566 |
| | 197,723 | 211,419 | 295,400 |
| Project expenses | | | |
| Chambers | 38,377 | 40,540 | 44,264 |
| Mid-Georgia | — | 6,519 | 13,509 |
| Badger Creek | 11,723 | 10,897 | 18,021 |
| Gregory | 27,324 | 24,893 | 53,101 |
| Orlando | 39,898 | 38,694 | 31,819 |
| Selkirk | 48,496 | 44,045 | 64,087 |
| Other | 2,049 | 22,560 | 25,436 |
| | 167,867 | 188,148 | 250,237 |
| Project other income (expense) | | | |
| Chambers | (3,948) | (3,606) | (8,379) |
| Mid-Georgia | — | 13,137 | (3,551) |
| Badger Creek | (1,013) | (16) | (4) |
| Gregory | (1,805) | (1,793) | 288 |
| Orlando | (133) | (65) | 367 |
| Selkirk | (6,873) | (3,812) | (14,512) |
| Other | (2,307) | (4,822) | (17,477) |
| | (16,079) | (977) | (43,268) |
| Project income (loss) | | | |
| Chambers | $ 13,144 | $ 6,599 | $ 16,250 |
| Mid-Georgia | — | 13,139 | (2,068) |
| Badger Creek | 749 | 1,948 | 2,477 |
| Gregory | 2,162 | 1,791 | 4,621 |
| Orlando | 2,031 | 3,152 | 2,920 |
| Selkirk | (3,454) | (280) | (6,958) |
| Other | (855) | (4,055) | (15,347) |
| | $ 13,777 | $ 22,294 | $ 1,895 |

**5. Property, plant and equipment**

| | 2010 | 2009 | Depreciable Lives |
|---|---|---|---|
| Land | $ 3,321 | $ 2,081 | |
| Office equipment, machinery and other | 8,040 | 6,331 | 3 - 10 years |
| Leasehold improvements | 2,810 | 2,411 | 7 - 15 years |
| Plant in service | 353,002 | 257,566 | 1 - 30 years |
| | 367,173 | 268,389 | |
| Less accumulated depreciation | (91,752) | (74,567) | |
| | $275,421 | $193,822 | |

Depreciation expense of $11.1 million, $11.1 million and $6.6 million was recorded for the years ended December 31, 2010, 2009 and 2008, respectively.

**6. Other intangible assets and transmission system rights**

Other intangible assets include power purchase agreements that are not separately recorded as financial instruments, fuel supply agreements and development costs. Transmission system rights represent the long-term right to approximately 72% of the regulated revenues of the Path 15 transmission line.

The following tables summarize the components of our intangible assets subject to amortization for the years ended December 31, 2010 and 2009:

| | Transmission System Rights | Power Purchase Agreements | Fuel Supply Agreements | Development Costs | Total |
|---|---|---|---|---|---|
| Gross balances, December 31, 2010 | $231,669 | $110,470 | $ 33,845 | $1,147 | $ 377,131 |
| Less: accumulated amortization | (43,535) | (39,190) | (17,810) | — | (100,535) |
| Net carrying amount, December 31, 2010 | $188,134 | $ 71,280 | $ 16,035 | $1,147 | $ 276,596 |

| | Transmission System Rights | Power Purchase Agreements | Fuel Supply Agreements | Total |
|---|---|---|---|---|
| Gross balances, December 31, 2009 | $231,669 | $ 73,880 | $ 43,258 | $348,807 |
| Less: accumulated amortization | (35,685) | (26,608) | (18,760) | (81,053) |
| Net carrying amount, December 31, 2009 | $195,984 | $ 47,272 | $ 24,498 | $267,754 |

The following table presents amortization of intangible assets for the years ended December 31, 2010, 2009 and 2008:

| | 2010 | 2009 | 2008 |
|---|---|---|---|
| Transmission system rights | $ 7,849 | $ 7,849 | $ 7,506 |
| Power purchase agreements | 12,411 | 12,406 | 4,206 |
| Fuel supply agreements | 8,461 | 9,468 | 2,940 |
| Total amortization | $28,721 | $29,723 | $14,652 |

**6. Other intangible assets and transmission system rights (Continued)**

The following table presents estimated future amortization for the next five years related to our transmission system rights, purchase power agreements and fuel supply agreements:

| Year Ended December 31, | Transmission System Rights | Power Purchase Agreements | Fuel Supply Agreements | Total |
|---|---|---|---|---|
| 2011 | $7,849 | $14,452 | $8,461 | $30,762 |
| 2012 | 7,849 | 14,452 | 7,574 | 29,875 |
| 2013 | 7,849 | 12,080 | — | 19,929 |
| 2014 | 7,849 | 2,041 | — | 9,890 |
| 2015 | 7,849 | 2,041 | — | 9,890 |

**7. Credit facility**

We maintain a credit facility with a capacity of $100.0 million, $50.0 million of which may be utilized for letters of credit. The credit facility matures in August 2012.

In November 2008, we borrowed $55.0 million under the credit facility and used the proceeds to partially fund the acquisition of Auburndale. We executed an interest rate swap to fix the interest rate at 2.4% through November 2011 for $40.0 million of the balance outstanding under this borrowing. During 2009, the outstanding borrowings under the credit facility were repaid with cash on hand and the interest rate swap was terminated. The remaining amount in accumulated other comprehensive income for this swap was recorded as interest expense in the consolidated statement of operations.

In June 2010, we borrowed $20.0 million under the credit facility and used the proceeds to partially fund the acquisition of Idaho Wind in July 2010. In October 2010, we repaid the $20.0 million borrowing with proceeds from our common stock and convertible debt offerings.

The credit facility bears interest at the London Interbank Offered Rate (“LIBOR”) plus an applicable margin between 1.50% and 3.25% that varies based on certain credit statistics of one of our subsidiaries. As of December 31, 2010, the applicable margin was 1.5% (1.5% in 2009). As of December 31, 2010, $48.6 million of the credit facility capacity was allocated, but not drawn, to support letters of credit for contractual credit support at several of our projects.

We must meet certain financial covenants under the terms of the credit facility, which are generally based on our cash flow coverage ratio and indebtedness ratios and also require us to report indebtedness ratios to the bank. The facility is secured by pledges of assets and interests in certain subsidiaries. We expect to remain in compliance with the covenants of the credit facility for at least the next 12 months.

**8. Long-term debt**

Long-term debt represents project-level long-term debt of our consolidated subsidiaries and the unamortized balance of purchase accounting adjustments that were recorded in connection with the Path 15 acquisition in order to adjust the debt to its fair value on the acquisition date. Project debt is non-recourse to Atlantic Power and generally amortizes during the term of the respective revenue generating contracts of the projects.

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

| | December 31, 2010 | December 31, 2009 |
|---|---|---|
| Project debt, interest rates ranging from 5.1% to 9.0% maturing through 2028 | $254,581 | $230,331 |
| Purchase accounting fair value adjustments | 11,305 | 12,030 |
| Less: current portion of long-term debt | (21,587) | (18,280) |
| Long-term debt | $244,299 | $224,081 |

Principal payments due in the next five years and thereafter are as follows:

| | |
|---|---|
| 2011 | $ 21,587 |
| 2012 | 20,958 |
| 2013 | 19,702 |
| 2014 | 15,065 |
| 2015 | 16,999 |
| Thereafter | 160,270 |
| | $254,581 |

All of the debt in the table above is represented by non-recourse debt of the projects. Project-level debt is secured by the respective project and its contracts with no other recourse to us. The loans have certain financial covenants that must be met. At December 31, 2010, all of our projects were in compliance with the covenants contained in project-level debt. However, our Epsilon Power Partners, Gregory, Selkirk and Delta-Person projects had not achieved the levels of debt service coverage ratios required by the project-level debt arrangements as a condition to make distributions and were therefore restricted from making distributions to us.

The required coverage ratio at Epsilon Power Partners is calculated based on the most recent four quarters cash flow results from Chambers. Reduced cash flows resulted in the project not meeting cash flow coverage ratio tests in its non-recourse debt, so we received no distributions from Chambers in 2009 and in the first nine months of 2010. The Chambers project began to meet the cash flow coverage ratio for its non-recourse debt again as of September 30, 2010 and the project distributed $2.8 million to our project holding company, Epsilon Power Partners in October 2010. However, the required cash flow coverage ratio on the debt at Epsilon Power Partners has not been achieved and, as a result, Epsilon has not made any distributions to the Company during 2009 and 2010. Based on our current projections, Epsilon will continue receiving distributions from the project in 2011 based on meeting the required debt service coverage ratios and we expect Epsilon to resume making distributions to the Company in late 2011.

The required coverage ratio at Selkirk is calculated based on both historical project cash flows for the previous six months, as well as projected project cash flows for the next six months. Increased natural gas transportation costs attributable to a contractual price increase at Selkirk are the primary contributors to the project not currently meeting its minimum coverage ratio.

The required coverage ratio at Delta-Person is based on the most recent four-quarter period. In 2009, Delta-Person incurred higher than anticipated operations and maintenance costs due to an unanticipated repair. The higher operations and maintenance costs caused Delta-Person to fail its debt service coverage ratio and restrict cash distributions for 2010.

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

The required coverage ratio at Gregory is calculated based on both historical project cash flows for the previous six months, as well as projected cash flows for the next six months. Increased fuel costs in 2011 attributable to fuel hedges expiring at the end of 2010 are the primary contributors to the project not currently meeting its debt service coverage ratio requirements.

As at December 31, 2010, the amount of restricted net assets of our unconsolidated subsidiaries that may not be distributed to us in the form of a dividend is approximately $298.4 million and the amount of undistributed earnings of unconsolidated subsidiaries was approximately $151.3 million. Project-level debt is secured by the respective projects and their contracts with no other recourse to us. At December 31, 2010, all of our projects were in compliance with the covenants contained in project-level debt agreements.

**9. Subordinated notes**

On November 27, 2009 our shareholders approved a conversion from the IPS structure to a traditional common share structure. Each IPS has been exchanged for one new common share of Atlantic Power and each old common share that did not form part of an IPS was exchanged for approximately 0.44 of a new common share. This transaction resulted in the extinguishment of Cdn$347.8 million ($327.7 million) principal value of subordinated notes.

A loss on the common share conversion in the amount of $13.1 million was recorded in interest expense within administrative and other expenses and was comprised of the write off of unamortized deferred financing costs of $7.5 million, the costs associated with the common share conversion of $4.7 million and the write off of the unamortized subordinated note premium of $0.9 million.

On December 17, 2009, we exercised our subordinated note call option to redeem the remaining Cdn$40.7 million ($38.7 million) principal value of Subordinated Notes at 105% of the principal amount. A loss on the redemption of the subordinated notes in the amount of $3.1 million was recorded in interest expense within administrative and other expenses and was comprised of the write off of unamortized deferred financing costs of $1.2 million and the 5% premium paid in the amount of $1.9 million.

The subordinated notes were due to mature in November 2016 subject to redemption under specified conditions at the option of Atlantic Power, commencing on or after November 18, 2009. Interest was payable monthly in arrears at an annual rate of 11% and the principal repayment was to occur at maturity.

The subordinated notes were denominated in Canadian dollars and were secured by a subordinated pledge of our interest in certain subsidiaries, and contained certain restrictive covenants. Cdn$39.5 million principal value of the subordinated notes were separately held by two investors and the remaining amount of the outstanding subordinated notes formed a part of our publicly traded IPSs.

Interest expense related to the subordinated notes was $36.4 million and $40.2 million for the years ended December 31, 2009 and 2008, respectively.

**10. Convertible debentures**

In 2006 we issued, in a public offering, Cdn$60 million aggregate principal amount of 6.25% convertible secured debentures (the "2006 Debentures") for gross proceeds of $52.8 million. The 2006

**10. Convertible debentures (Continued)**

Debentures pay interest semi-annually on April 30 and October 31 of each year. The 2006 Debentures had an initial maturity date of October 31, 2011 and are convertible into approximately 80.6452 common shares per Cdn$1,000 principal amount of 2006 Debentures, at any time, at the option of the holder, representing a conversion price of Cdn$12.40 per common share.

In connection with the common share conversion on November 27, 2009, the holders of the 2006 Debentures approved an amendment to increase the annual interest rate from 6.25% to 6.50% and separately, an extension of the maturity date from October 2011 to October 2014.

During 2010, Cdn$4.2 million of the 2006 Debentures were converted to 338,627 common shares. As of December 31, 2010 the 2006 Debentures balance is Cdn$55.8 million ($56.1 million).

On December 17, 2009, we issued, in a public offering, Cdn$86.3 million aggregate principal amount of 6.25% convertible unsecured debentures (the "2009 Debentures") for gross proceeds of $82.1 million. The 2009 Debentures pay interest semi-annually on March 15 and September 15 of each year beginning on September 15, 2010. The 2009 Debentures mature on March 15, 2017 and are convertible into approximately 76.9231 common shares per Cdn$1,000 principal amount of 2009 Debentures, at any time, at the option of the holder, representing a conversion price of Cdn$13.00 per common share.

During 2010, Cdn$3.1 million of the 2009 Debentures were converted to 240,458 common shares. As of December 31, 2010 the 2009 Debentures balance is Cdn$83.1 million ($83.6 million).

On October 20, 2010, we issued, in a public offering, Cdn$80.5 million aggregate principal amount of 5.60% convertible unsecured subordinated debentures (the "2010 Debentures") for gross proceeds of $78.9 million. The 2010 Debentures pay interest semi-annually on June 30 and December 30 of each year beginning June 30, 2011. The 2010 Debentures mature on June 30, 2017, unless earlier redeemed. The debentures are convertible into our common shares at an initial conversion rate of 55.2486 common shares per Cdn$1,000 principal amount of 2010 Debentures, at any time, at the option of the holder, representing an initial conversion price of approximately Cdn$18.10 per common share. As of December 31, 2010 the 2010 Debentures balance is Cdn$80.5 million ($80.9 million).

Aggregate interest expense related to the 2006, 2009 and 2010 Debentures was $9.9 million, $3.5 million and $3.5 million for the years ended December 31, 2010, 2009 and 2008, respectively.

**11. Fair value of financial instruments**

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

| | 2010 | | 2009 | |
|---|---|---|---|---|
| | Carrying Amount | Fair Value | Carrying Amount | Fair Value |
| Cash and cash equivalents | $ 45,497 | $ 45,497 | $ 49,850 | $ 49,850 |
| Restricted cash | 15,744 | 15,744 | 14,859 | 14,859 |
| Derivative assets current | 8,865 | 8,865 | 5,619 | 5,619 |
| Derivative assets non-current | 17,884 | 17,884 | 14,289 | 14,289 |
| Derivative liabilities current | 10,009 | 10,009 | 6,512 | 6,512 |
| Derivative liabilities non-current | 21,543 | 21,543 | 5,513 | 5,513 |
| Long-term debt, including current portion | 265,886 | 281,491 | 242,361 | 267,765 |
| Convertible debentures | 220,616 | 242,316 | 139,153 | 141,251 |

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

The three levels of the fair value hierarchy are defined below:

Level 1—Unadjusted quoted prices available in active markets for identical assets or liabilities as of the reporting date. Financial assets utilizing Level 1 inputs include active exchange-traded securities.

Level 2—Quoted prices available in active markets for similar assets or liabilities, quoted prices for identical or similar assets or liabilities in inactive markets, inputs other than quoted prices that are directly observable, and inputs derived principally from market data.

Level 3—Unobservable inputs from objective sources. These inputs may be based on entity-specific inputs. Level 3 inputs include all inputs that do not meet the requirements of Level 1 or Level 2.

The following represents the recurring measurements of fair value hierarchy of our financial assets and liabilities that were recognized at fair value as of December 31, 2010 and December 31, 2009. Financial assets and liabilities are classified based on the lowest level of input that is significant to the fair value measurement.

| | December 31, 2010 | | | |
|---|---|---|---|---|
| | Level 1 | Level 2 | Level 3 | Total |
| Assets: | | | | |
| Cash and cash equivalents | $45,497 | $ — | $— | $45,497 |
| Restricted cash | 15,744 | — | — | 15,744 |
| Derivative instruments asset | — | 26,749 | — | 26,749 |
| Total | $61,241 | $26,749 | $— | $87,990 |
| Liabilities: | | | | |
| Derivative instruments liability | $ — | $31,552 | $— | $31,552 |
| Total | $ — | $31,552 | $— | $31,552 |

**11. Fair value of financial instruments (Continued)**

| | December 31, 2009 | | | |
|---|---|---|---|---|
| | Level 1 | Level 2 | Level 3 | Total |
| Assets: | | | | |
| Cash and cash equivalents | $49,850 | $ — | $— | $49,850 |
| Restricted cash | 14,859 | — | — | 14,859 |
| Derivative instruments asset | — | 19,908 | — | 19,908 |
| Total | $64,709 | $19,908 | $— | $84,617 |
| Liabilities: | | | | |
| Derivative instruments liability | $ — | $12,025 | $— | $12,025 |
| Total | $ — | $12,025 | $— | $12,025 |

The fair value of our derivative instruments are based on price quotes from brokers in active markets who regularly facilitate those transactions and we believe such price quotes are executable. We adjust the fair value of financial assets and liabilities to reflect credit risk, which is calculated based on our credit rating or the credit rating of our counterparties. As of December 31, 2010, the credit reserve resulted in a $0.6 million net increase in fair value, which is comprised of a $0.2 million pre-tax gain in other comprehensive income and a $0.5 million gain in change in fair value of derivative instruments offset by a $0.1 million loss in foreign exchange. As of December 31, 2009, the credit reserve resulted in a $0.1 million increase in fair value which is comprised of a $0.1 million gain in OCI and a $0.3 million gain in change in fair value of derivative instruments and a $0.3 million loss in foreign exchange.

The carrying amounts for cash and cash equivalents and restricted cash approximate fair value due to their short-term nature. The fair value of long-term debt, subordinated notes and convertible debentures was determined using quoted market prices, as well as discounting the remaining contractual cash flows using a rate at which we could issue debt with a similar maturity as of the balance sheet date.

As of December 31, 2007, approximately $26 million of our cash and cash equivalents were invested in auction-rate securities (“ARSs”). ARSs typically have an underlying maturity of up to 40 years but have historically traded in seven or 28 day intervals in a highly liquid market. The ARSs that were held at December 31, 2007 were redeemed at auctions held in January 2008 and the proceeds were re-invested in ARSs.

In early 2008, the overall market for ARSs suffered a significant decline in liquidity and most of the auctions of ARSs were unsuccessful, resulting in our continuing to hold these securities and the issuers paying interest at the maximum contractual rate. In September and November 2008, all of our investments in ARSs were sold at par plus accrued interest for $36.5 million. Purchases and sales of ARSs are presented gross in the consolidated statements of cash flows because they are classified as available-for-sale securities.

**12. Accounting for derivative instruments and hedging activities**

*Fair value of derivative instruments*

We have elected to disclose derivative instruments assets and liabilities on a trade-by-trade basis and do not offset amounts at the counterparty master agreement level. The following table summarizes the fair value of our derivative assets and liabilities:

| | December 31, 2010 | |
|---|---|---|
| | Derivative Assets | Derivative Liabilities |
| Derivative instruments designated as cash flow hedges: | | |
| Interest rate swap current | $ — | $ 2,124 |
| Interest rate swap long-term | — | 2,626 |
| Total derivative instruments designated as cash flow hedges | — | 4,750 |
| Derivative instruments not designated as cash flow hedges: | | |
| Interest rate swap current | — | 1,286 |
| Interest rate swap long-term | 3,299 | 2,000 |
| Foreign currency forward contracts current | 8,865 | — |
| Foreign currency forward contracts long-term | 14,585 | — |
| Natural gas swap current | — | 6,599 |
| Natural gas swap long-term | — | 16,917 |
| Total derivative instruments not designated as cash flow hedges | 26,749 | 26,802 |
| Total derivative instruments | $26,749 | $31,552 |

| | December 31, 2009 | |
|---|---|---|
| | Derivative Assets | Derivative Liabilities |
| Derivative instruments designated as cash flow hedges: | | |
| Interest rate swap current | $ — | $ 726 |
| Interest rate swap long-term | — | 167 |
| Total derivative instruments designated as cash flow hedges | — | 893 |
| Derivative instruments not designated as cash flow hedges: | | |
| Interest rate swap current | — | 1,705 |
| Interest rate swap long-term | — | 1,707 |
| Foreign currency forward contracts current | 5,619 | — |
| Foreign currency forward contracts long-term | 14,289 | — |
| Natural gas swap current | 95 | 4,174 |
| Natural gas swap long-term | 14 | 3,655 |
| Total derivative instruments not designated as cash flow hedges | 20,017 | 11,241 |
| Total derivative instruments | $20,017 | $12,134 |

**12. Accounting for derivative instruments and hedging activities (Continued)**

*Natural gas swaps*

The Lake project's operating margin is exposed to changes in natural gas spot market prices from the expiration of its natural gas supply contract on June 30, 2009 through the expiration of its PPA on July 31, 2013. The Auburndale project purchases natural gas under a fuel supply agreement which provides approximately 80% of the project's fuel requirements at fixed prices through June 30, 2012. The remaining 20% is purchased at spot market prices and therefore the project is exposed to changes in natural gas prices for that portion of its gas requirements through the termination of the fuel supply agreement and 100% of its natural gas requirements from the expiry of the fuel supply agreement in mid-2012 until the termination of its PPA at the end of 2013.

The Orlando project's operating margin is exposed to changes in natural gas spot market prices from the expiration of its gas supply agreement in 2013 until its PPA expires in 2023. In October 2010, we executed two fuel swap agreements which become effective on January 1, 2014 and January 1, 2015 and terminate on December 31, 2014 and 2015, respectively. These swap agreements were entered into at Atlantic Power Corporation and not at the project level. Orlando is accounted for under the equity method of accounting.

Our strategy to mitigate the future exposure to changes in natural gas prices at Lake, Auburndale and Orlando consists of periodically entering into financial swaps that effectively fix the price of natural gas expected to be purchased at these projects. These natural gas swaps are derivative financial instruments and are recorded in the consolidated balance sheet at fair value.

Changes in the fair value of the natural gas swaps related to Lake and Auburndale through June 30, 2009 were recorded in other comprehensive income (loss) as they were designated as a hedge of the risk associated with changes in market prices of natural gas. As of July 1, 2009, we de-designated these natural gas swap hedges and the changes in their fair value subsequent to July 1, 2009 are now recorded in change in fair value of derivative instruments in the consolidated statements of operations. Amounts in accumulated other comprehensive income (loss) remaining prior to de-designation are amortized into the consolidated statements of operations over the remaining term of the natural gas swaps.

*Interest Rate Swaps*

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

The interest rate swap is a derivative financial instrument designated as a cash flow hedge and is recorded in the balance sheet at fair value. Changes in the fair value of the interest rate swap are recorded in accumulated other comprehensive income (loss) and reclassified to interest expense when settled in cash. This swap agreement is effective November 2009 through November 2013.

In February 2008, Cadillac entered into an interest rate swap agreement that effectively fixed the interest rate at 5.90% from February 20, 2008 to February 15, 2011, 6.02% from February 16, 2011 to February 15, 2015, 6.14% from February 16, 2015 to February 15, 2019, 6.26% from February 16, 2019 to February 15, 2023, and 6.38% thereafter. The notional amount of the interest rate swap agreement

**12. Accounting for derivative instruments and hedging activities (Continued)**

mirrors the outstanding principal balance over the remaining life of Cadillac's debt. This swap agreement, which qualifies and is designated as a cash flow hedge, is effective through June 2025.

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

*Impact of derivative instruments on the consolidated income statements*

Unrealized gains on interest rate swaps designated as cash flow hedges, net of tax, have been recorded in the consolidated statements of shareholders' equity as a gain in other comprehensive income of $0.4 million, $0.6 million and $0.5 million for the years ended December 31, 2010, 2009 and 2008, respectively. Realized losses on these interest rate swaps of $0.5 million, $0.5 million and $0.0 million were recorded in interest expense, net for the years ended December 31, 2010, 2009 and 2008, respectively.

Unrealized gains and losses on natural gas swaps previously designated as cash flow hedges are recorded in other comprehensive income. In the period in which the unrealized gains and losses are settled, the cash settlement payments are recorded as fuel expense. Other comprehensive loss recorded for natural gas swap contracts accounted for as cash flow hedges totaled $5.1 million, net of tax, prior to July 1, 2009 when hedge accounting for these natural gas swaps was discontinued prospectively. Amortization of the loss of $1.0 million and $4.3 million, net of tax, was recorded in change in fair value of derivative instruments for the years ended December 31, 2010 and 2009, respectively.

Unrealized gains and losses on derivative instruments not designated as cash flow hedges are recorded in change in fair value of derivative instruments in the consolidated statements of operations.

The following table summarizes realized gains and losses for derivative instruments not designated as cash flow hedges:

| | Classification of (gain) loss recognized in income | 2010 | 2009 |
|---|---|---|---|
| Natural gas swaps | Fuel | $ 9,141 | $10,089 |
| Foreign currency forwards | Foreign exchange gain | (6,625) | (3,864) |
| Interest rate swaps | Interest, net | 1,664 | 1,446 |

Unrealized gains and losses associated with changes in the fair value of derivative instruments not designated as cash flow hedges and ineffectiveness of derivatives designated as cash flow hedges are reflected in current period earnings. The following table summarizes the pre-tax (gains) and losses

**12. Accounting for derivative instruments and hedging activities (Continued)**

resulting from changes in the fair value of derivative financial instruments that are not designated as cash flow hedges:

| | 2010 | 2009 | 2008 |
|---|---|---|---|
| Change in fair value of derivative instruments: | | | |
| Interest rate swaps | $(3,423) | $ 369 | $ (1,804) |
| Indexed swap and hedge | — | — | (10,844) |
| Natural gas swaps | 17,470 | (7,182) | (3,378) |
| | $14,047 | $(6,813) | $(16,026) |

*Volume of forecasted transactions*

We entered into derivative instruments in order to economically hedge the following notional volumes of forecasted transactions as summarized below, by type, excluding those derivatives that qualified for the normal purchases and normal sales exception as of December 31, 2010:

| | Units | December 31, 2010 |
|---|---|---|
| Interest rate swaps | Interest (US$) | $ 44,228 |
| Currency forwards | Dollars (Cdn$) | $219,800 |
| Natural gas swaps | Natural Gas (Mmbtu) | 15,540 |

*Foreign currency forward contracts*

We use foreign currency forward contracts to manage our exposure to changes in foreign exchange rates, as we generate cash flow in U.S. dollars but pay dividends to shareholders and interest on convertible debentures predominantly in Canadian dollars. We have a hedging strategy for the purpose of mitigating the currency risk impact on the long-term sustainability of dividends to shareholders. We have executed this strategy by entering into forward contracts to purchase Canadian dollars at a fixed rate to hedge approximately 86% of our expected dividend and convertible debenture interest payments through 2013. Changes in the fair value of the forward contracts partially offset foreign exchange gain or losses on the U.S. dollar equivalent of our Canadian dollar obligations. The forward contracts consist of (1) monthly purchases through the end of 2013 of Cdn$6.0 million at an exchange rate of Cdn$1.134 per U.S. dollar and (2) purchases in both April and October 2011 of Cdn$1.9 million at an exchange rate of Cdn$1.1075 per U.S. dollar.

It is our intention to periodically consider extending the length of these forward contracts. In addition, we will consider executing additional foreign currency forward contracts to hedge expected additional dividend and interest payments associated with the common shares and convertible debentures issued in our October 2010 public offering (see Note 10 and Note 18).

The foreign exchange forward contracts are recorded at estimated fair value based on quoted market prices and our estimation of the counterparty's credit risk. The fair value of our forward foreign currency contracts is $23.4 million and $19.9 million for the years ended December 31, 2010 and 2009, respectively. Changes in the fair value of the foreign currency forward contracts are recorded in foreign exchange (gain) loss in the consolidated statements of operations.

**12. Accounting for derivative instruments and hedging activities (Continued)**

The following table contains the components of recorded foreign exchange (gain) loss for the years ended December 31, 2010, 2009 and 2008:

| | 2010 | 2009 | 2008 |
|---|---|---|---|
| Unrealized foreign exchange (gain) loss: | | | |
| Subordinated notes and convertible debentures | $ 9,153 | $ 55,508 | $(85,212) |
| Forward contracts and other | (3,542) | (31,138) | 46,009 |
| | 5,611 | 24,370 | (39,203) |
| Realized foreign exchange gains on forward contract settlements | (6,625) | (3,864) | (8,044) |
| | $(1,014) | $ 20,506 | $(47,247) |

The following table illustrates the impact on the fair value of our financial instruments of a 10% hypothetical change in the value of the U.S. dollar compared to the Canadian dollar as of December 31, 2010:

| | |
|---|---|
| Convertible debentures | $ 22,062 |
| Foreign currency forward contracts | $(23,893) |

The following tables summarize the changes in the accumulated other comprehensive income (loss) ("OCI") balance attributable to derivative financial instruments designated as a hedge, net of tax:

| Year ended December 31, 2010 | Interest Rate Swaps | Natural Gas Swaps | Total |
|---|---|---|---|
| Accumulated OCI balance at December 31, 2009 | $ (538) | $ (321) | $ (859) |
| Change in fair value of cash flow hedges | (360) | — | (360) |
| Realized from OCI during the period | 471 | 1,003 | 1,474 |
| Accumulated OCI balance at December 31, 2010 | $ (427) | $ 682 | $ 255 |

| Year ended December 31, 2009 | Interest Rate Swaps | Natural Gas Swaps | Total |
|---|---|---|---|
| Accumulated OCI balance at December 31, 2008 | $(501) | $(2,635) | $(3,136) |
| Change in fair value of cash flow hedges | (565) | (1,985) | (2,550) |
| Realized from OCI during the period | 528 | 4,299 | 4,827 |
| Accumulated OCI balance at December 31, 2009 | $(538) | $ (321) | $ (859) |

**13. Income taxes**

| | 2010 | 2009 | 2008 |
|---|---|---|---|
| Current income tax expense (benefit) | $ 960 | $ (9,257) | $ 449 |
| Deferred tax expense (benefit) | 17,964 | (6,436) | (14,009) |
| Total income tax expense (benefit) | $18,924 | $(15,693) | $(13,560) |

**13. Income taxes (Continued)**

The following is a reconciliation of income taxes calculated at the Canadian enacted statutory rate of 28.5%, 30.0% and 33.5% at December 31, 2010, 2009 and 2008, respectively, to the provision for income taxes in the consolidated statements of operations:

| | 2010 | 2009 | 2008 |
|---|---|---|---|
| Computed income taxes at Canadian statutory rate | $ 4,295 | $(16,254) | $ 11,571 |
| Increases (decreases) resulting from: | | | |
| Operating countries with different income tax rates | 1,537 | (5,418) | 2,245 |
| | $ 5,832 | $(21,672) | $ 13,816 |
| Valuation allowance | 12,289 | 22,005 | (37,111) |
| | 18,121 | 333 | (23,295) |
| Dividend withholding tax | 765 | — | — |
| Permanent differences | — | (1,131) | 10,787 |
| Canadian loss carryforwards | — | (13,204) | (2,787) |
| Branch profits tax | — | — | 2,368 |
| Prior year true-up | — | (1,970) | (841) |
| Other | 38 | 279 | 208 |
| | 803 | (16,026) | 9,735 |
| | $18,924 | $(15,693) | $(13,560) |

The tax effect of temporary differences that give rise to significant portions of the deferred tax assets and deferred tax liabilities at December 31, 2010 and 2009 are presented below:

| | 2010 | 2009 |
|---|---|---|
| Deferred tax assets: | | |
| Intangible assets | $ 37,488 | $ 45,237 |
| Loss carryforwards | 58,702 | 62,926 |
| Other accrued liabilities | 18,869 | 16,212 |
| IPS and issuance costs | 2,312 | 1,374 |
| Natural gas and interest rate hedges | — | 573 |
| Other | 130 | — |
| Total deferred tax assets | 117,501 | 126,322 |
| Valuations allowance | (79,420) | (67,131) |
| | 38,081 | 59,191 |
| Deferred tax liabilities: | | |
| Property, plant and equipment | (66,535) | (69,639) |
| Natural gas and interest rate hedges | (170) | — |
| Unrealized foreign exchange gain | (815) | (284) |
| Total deferred tax liabilities | (67,520) | (69,923) |
| Net deferred tax liability | $(29,439) | $(10,732) |

**13. Income taxes (Continued)**

The following table summarizes the net deferred tax position as of December 31, 2010 and 2009:

| | 2010 | 2009 |
|---|---|---|
| Current deferred tax assets | $ — | $ 17,887 |
| Long-term deferred tax liabilities | (29,439) | (28,619) |
| Net deferred tax asset (liability) | $(29,439) | $(10,732) |

As of December 31, 2010, we have recorded a valuation allowance of $79.4 million. This amount is comprised primarily of provisions against available Canadian and U.S. net operating loss carryforwards. In assessing the recoverability of our deferred tax assets, we consider whether it is more likely than not that some portion or all of the deferred tax assets will be realized. The ultimate realization of deferred tax assets is dependent upon projected future taxable income in the United States and in Canada and available tax planning strategies.

As of December 31, 2010, we had the following net operating loss carryforwards that are scheduled to expire in the following years:

| | |
|---|---|
| 2026 | $ 37,525 |
| 2027 | 45,960 |
| 2028 | 44,176 |
| 2029 | 59,930 |
| 2030 | 2,596 |
| | $190,187 |

**14. Long-Term Incentive Plan**

The following table summarizes the changes in outstanding LTIP notional units during the years ended December 31, 2010, 2009 and 2008:

| | Units | Grant Date Weighted-Average Fair Value per Unit |
|---|---|---|
| Outstanding at December 31, 2007 | 179,028 | $ 9.43 |
| Granted | 142,717 | 9.99 |
| Additional shares from dividends | 28,138 | 9.71 |
| Forfeited | (37,944) | 9.43 |
| Vested | (48,346) | 9.43 |
| Outstanding at December 31, 2008 | 263,593 | 9.76 |
| Granted | 267,408 | 5.76 |
| Additional shares from dividends | 49,540 | 7.80 |
| Vested | (109,260) | 9.71 |
| Outstanding at December 31, 2009 | 471,281 | 7.30 |
| Granted | 305,112 | 13.29 |
| Additional shares from dividends | 46,854 | 9.54 |
| Vested | (222,265) | 7.94 |
| Outstanding at December 31, 2010 | 600,981 | $10.28 |

In the second quarter of 2010, the Board of Directors approved an amendment to the LTIP. The amended LTIP will be effective for grants beginning with the 2010 performance year. Under the amended LTIP, the notional units granted to plan participants will have the same characteristics as notional units under the old LTIP. However, the number of notional units that vest will be based, in part, on the total shareholder return of Atlantic Power compared to a group of peer companies in Canada. In addition, vesting of the notional units for officers of Atlantic Power will occur on a three year cliff basis as opposed to ratable vesting over three years for grants made prior to the amendment.

Vested notional units are expected to be redeemed one-third in cash and two-thirds in shares of our common stock. Notional units granted that are expected to be redeemed in cash upon vesting are accounted for as liability awards. Notional units granted that are expected to be redeemed in common shares upon vesting are accounted for as equity awards. Notional units granted prior to the 2010 performance period are subject to the vesting conditions of the LTIP before the amendments made in 2010. We reclassified the portion of outstanding awards expected to vest in common shares totaling $1.4 million from accounts payable and accrued liabilities and other non-current liabilities to common shares as of June 29, 2010, the date the amended LTIP was approved by our shareholders.

On March 29, 2010, our board of directors approved the grant of 138,892 notional LTIP units for the 2009 performance period under the terms of the LTIP before the 2010 amendments. In May 2010, our board of directors approved the initial grant of 83,110 notional LTIP units for executive officers under the amended LTIP for the 2010-2012 performance period, subject to final shareholder approval of the amended LTIP, which occurred on June 29, 2010. Also in May 2010 and subject to the final shareholder approval of the amended LTIP, our board of directors granted transition awards to our executive officers consisting of an additional 83,110 notional LTIP units. The transition awards are designed to mitigate the impact of the changes in vesting provisions of the LTIP from a ratable vesting

**14. Long-Term Incentive Plan (Continued)**

over three years to cliff vesting at the end of three years. The transition awards are subject to the performance measurement and other provisions of the amended LTIP, except that one-third of the transition awards vest in the first quarter of 2011 and the other two-thirds vest in the first quarter of 2012.

The notional units, other than the transition awards, granted under the amended LTIP cliff-vest three years after the grant date. The final number of notional units that will vest, if any, at the end of the three year vesting period will be based on our achievement of target levels of relative total shareholder return, which is the change in the value of an investment in our common stock, including reinvestment of dividends, compared to that of a peer group of companies during the performance period. The total number of notional units vesting will range from zero up to a maximum 150% of the number of notional units in the executives' accounts on the vesting date for that award, depending on the level of achievement of relative total shareholder return during the measurement period.

Compensation expense related to awards granted to participants in the LTIP is recorded over the vesting period based on the estimated fair value of the award on the grant date for notional units accounted for as equity awards and the fair value of the award at each balance sheet date for notional units accounted for as liability awards. Fair value of the awards granted prior to the 2010 LTIP amendment is determined by projecting the total number of notional units that will vest in future periods, including dividends received on notional units during the vesting period, and applying the current market price per share to the projected number of notional units that will vest. The fair value of awards granted in 2010 under the amended LTIP with market vesting conditions is based upon a Monte Carlo simulation model on their grant date. Compensation expense is recognized regardless of the relative total shareholder return performance, provided that the LTIP participant remains employed by Atlantic Power Corporation. The fair value of all outstanding notional units under the amended LTIP at December 31, 2010, is approximately $7.8 million. The aggregate number of shares which may be issued from treasury under the amended LTIP is limited to one million. Unvested notional units are recorded as either a liability or equity award based on management's intended method of redeeming the notional units when they vest.

Both the total shareholder return performance and the fair value of the notional units under the Monte Carlo simulation are determined with the assistance of a third party.

In calculating the fair value of the awards granted in 2010 under the amended LTIP, the Monte Carlo simulation model utilizes multiple input variables over the performance period in order to determine the likely relative total shareholder return. The Monte Carlo simulation model computed simulated our total shareholder return and for our peer companies during the remaining time in the performance period with the following inputs: (i) stock price on the measurement date; (ii) expected volatility; (iii) risk-free interest rate; (iv) dividend yield; and (v) correlations of historical common stock returns between Atlantic Power Coporation and the peer companies and among the peer companies. Expected volatilities utilized in the Monte Carlo model are based on historical volatility of the Company's and the peer companies' stock prices over a period equal in length to that of the remaining vesting period. The risk free interest rate is derived from the U.S. Treasury yield curve in effect at the time of grant with a term equal to the performance period assumption at the time of grant.

**14. Long-Term Incentive Plan (Continued)**

The calculation of simulated total shareholder return under the Monte Carlo model for the remaining time in the performance period included the following assumptions:

| | Year ended December 31, 2010 |
|---|---|
| Weighted average risk free rate of return | 0.71% |
| Dividend yield | 9.39% |
| Expected volatility—Company | 40.0% |
| Expected volatility—peer companies | 25.0 - 55.0% |
| Weighted average remaining measurement period | 1.43 years |

**15. Basic and diluted earnings (loss) per share**

Basic earnings (loss) per share is calculated by dividing net income (loss) by the weighted average common shares outstanding during their respective period. Diluted earnings (loss) per share is computed including dilutive potential shares as if they were outstanding shares during the year. Dilutive potential shares include shares that would be issued if all of the convertible debentures were converted into shares at January 1, 2010. Dilutive potential shares also include the weighted average number of shares, as of the date such notional units were granted, that would be issued if the unvested notional units outstanding under the LTIP were vested and redeemed for shares under the terms of the LTIP.

Because we reported a loss for the years ended December 31, 2010 and 2009, diluted earnings per share are equal to basic earnings per share as the inclusion of potentially dilutive shares in the computation is anti-dilutive.

The following table sets forth the diluted net income and potentially dilutive shares utilized in the per share calculation for the years ended December 31, 2010, 2009 and 2008:

| | 2010 | 2009 | 2008 |
|---|---|---|---|
| **Numerator:** | | | |
| Net income (loss) attributable to Atlantic Power Corporation | $(3,752) | $(38,486) | $48,101 |
| Add: interest expense for potentially dilutive convertible debentures, net(1) | — | — | 382 |
| Diluted net loss attributable to Atlantic Power Corporation | (3,752) | (38,486) | 48,483 |

(1) The above adjustment for net interest on the potential common shares that would be issued on the conversion of the convertible debentures has been determined by eliminating the actual interest on the convertible debentures and, for periods prior to our conversion from an IPS to common share structure on November 27, 2009, including the imputed interest on the additional subordinated notes that would be issued on the conversion (the conversion of the debentures is into additional IPSs, each consisting of one common share and Cdn$5.767 principal amount of subordinated notes).

**15. Basic and diluted earnings (loss) per share (Continued)**

| | 2010 | 2009 | 2008 |
|---|---|---|---|
| **Denominator:** | | | |
| Basic shares outstanding | 61,706 | 60,632 | 61,290 |
| Dilutive potential shares: | | | |
| Convertible debentures | 12,339 | 5,095 | 4,839 |
| LTIP notional units | 542 | 476 | 221 |
| Potentially dilutive shares | 74,587 | 66,203 | 66,350 |
| Diluted EPS | $ (0.06) | $ (0.63) | $ 0.73 |

Potentially dilutive shares from convertible debentures and potentially dilutive shares from LTIP notional units have been excluded from fully diluted shares in the years ended December 31, 2010 and 2009 because their impact would be anti-dilutive.

**16. Segment and related information**

We have six reportable segments: Path 15, Auburndale, Lake, Pasco, Chambers and Other Project Assets.

We analyze the performance of our operating segments based on Project Adjusted EBITDA which is defined as project income less interest, taxes, depreciation and amortization (including non-cash impairment charges) and changes in fair value of derivative instruments. Project Adjusted EBITDA is not a measure recognized under GAAP and does not have a standardized meaning prescribed by GAAP and is therefore unlikely to be comparable to similar measures presented by other companies. We use Project Adjusted EBITDA to provide comparative information about project performance without considering how projects are capitalized or whether they contain derivative contracts that are

### 16. Segment and related information (Continued)

required to be recorded at fair value. A reconciliation of project income to Project Adjusted EBITDA is included in the table below.

| | Path 15 | Auburndale | Lake | Pasco | Chambers | Other Project Assets | Un-allocated Corporate | Consolidated |
|---|---|---|---|---|---|---|---|---|
| **Year ended December 31, 2010:** | | | | | | | | |
| Operating revenues | $ 31,000 | $ 77,876 | $ 74,024 | $11,305 | $ — | $ 1,051 | $ — | $ 195,256 |
| Segment assets | 210,733 | 107,336 | 112,481 | 39,241 | — | 143,972 | 399,249 | 1,013,012 |
| Capital expenditures | — | 59 | 1,642 | 551 | — | 44,323 | 120 | 46,695 |
| Goodwill | 8,918 | — | — | — | — | 3,535 | — | 12,453 |
| Project Adjusted EBITDA | $ 28,639 | $ 34,232 | $ 31,428 | $ 4,712 | $19,344 | $ 34,229 | $ — | $ 152,584 |
| Change in fair value of derivative instruments | — | 8,591 | 8,731 | — | (1,317) | 1,638 | — | 17,643 |
| Depreciation and amortization | 8,387 | 19,813 | 9,097 | 3,001 | 3,371 | 22,122 | — | 65,791 |
| Interest, net | 12,401 | 1,631 | (9) | (8) | 6,260 | 3,353 | — | 23,628 |
| Other project (income) expense | | — | | | 761 | 2,882 | — | 3,643 |
| Project income | 7,851 | 4,197 | 13,609 | 1,719 | 10,269 | 4,234 | — | 41,879 |
| Interest, net | — | — | — | — | — | — | 11,701 | 11,701 |
| Administration | — | — | — | — | — | — | 16,149 | 16,149 |
| Foreign exchange gain | — | — | — | — | — | — | (1,014) | (1,014) |
| Other income, net | — | — | — | — | — | — | (26) | (26) |
| Income from operations before income taxes | 7,851 | 4,197 | 13,609 | 1,719 | 10,269 | 4,234 | (26,810) | 15,069 |
| Income tax expense (benefit) | 162 | — | — | — | — | — | 18,762 | 18,924 |
| Net income | $ 7,689 | $ 4,197 | $ 13,609 | $ 1,719 | $10,269 | $ 4,234 | $(45,572) | $ (3,855) |

| | Path 15 | Auburndale | Lake | Pasco | Chambers | Other Project Assets | Un-allocated Corporate | Consolidated |
|---|---|---|---|---|---|---|---|---|
| **Year ended December 31, 2009:** | | | | | | | | |
| Operating revenues | $ 31,000 | $ 74,875 | $ 62,285 | $11,357 | $ — | $ — | $ — | $179,517 |
| Segment assets | 219,586 | 130,053 | 118,925 | 42,479 | — | — | 358,533 | 869,576 |
| Capital expenditures | — | 321 | 1,278 | 355 | — | | 62 | 2,016 |
| Goodwill | 8,918 | — | — | — | — | — | — | 8,918 |
| Project Adjusted EBITDA | $ 27,691 | $ 35,221 | $ 25,378 | $ 3,299 | $13,595 | $38,995 | $ — | $144,179 |
| Change in fair value of derivative instruments | — | 2,118 | 5,064 | — | (2,604) | 469 | — | 5,047 |
| Depreciation and amortization | 8,511 | 19,780 | 10,098 | 2,987 | 3,390 | 22,877 | — | 67,643 |
| Interest, net | 12,911 | 2,833 | (4) | — | 7,674 | 8,097 | — | 31,511 |
| Other project (income) expense | (1,230) | — | — | (26) | 1,229 | (8,410) | — | (8,437) |
| Project income | 7,499 | 10,490 | 10,220 | 338 | 3,906 | 15,962 | — | 48,415 |
| Interest, net | — | — | — | — | — | — | 55,698 | 55,698 |
| Administration | — | — | — | — | — | — | 26,028 | 26,028 |
| Foreign exchange gain | — | — | — | — | — | — | 20,506 | 20,506 |
| Other income, net | — | — | — | — | — | — | 362 | 362 |
| Loss from operations before income taxes | 7,499 | 10,490 | 10,220 | 338 | 3,906 | 15,962 | (102,594) | (54,179) |
| Income tax expense (benefit) | — | — | — | — | — | — | (15,693) | (15,693) |
| Net loss | $ 7,499 | $ 10,490 | $ 10,220 | $ 338 | $ 3,906 | $15,962 | $ (86,901) | $(38,486) |

## 16. Segment and related information (Continued)

| | Path 15 | Auburndale | Lake | Pasco | Chambers | Other Project Assets | Un-allocated Corporate | Consolidated |
|---|---|---|---|---|---|---|---|---|
| **Year ended December 31, 2008:** | | | | | | | | |
| Operating revenues | $ 31,528 | $ 10,003 | $ 61,610 | $58,897 | $ — | $11,774 | $ — | $173,812 |
| Segment assets | 235,198 | 151,524 | 130,083 | 52,925 | — | — | 338,265 | 907,995 |
| Capital expenditures | — | — | 814 | 175 | | | 113 | 1,102 |
| Goodwill | 8,918 | — | — | — | — | — | — | 8,918 |
| Project Adjusted EBITDA | $ 28,872 | $ 4,461 | $ 32,892 | $21,953 | $27,603 | $58,908 | $ — | $174,689 |
| Change in fair value of derivative instruments | — | — | — | 3,378 | 4,295 | 22,241 | — | 29,914 |
| Depreciation and amortization | 7,917 | 2,127 | 11,232 | 11,154 | 2,974 | 24,721 | — | 60,125 |
| Interest, net | 13,232 | 225 | (32) | 978 | 8,536 | 7,377 | — | 30,316 |
| Other project expense | — | — | — | — | 580 | 12,748 | — | 13,328 |
| Project income | 7,723 | 2,109 | 21,692 | 6,443 | 11,218 | (8,179) | — | 41,006 |
| Interest, net | — | — | — | — | — | — | 43,275 | 43,275 |
| Administration | — | — | — | — | — | — | 10,012 | 10,012 |
| Foreign exchange gain | — | — | — | — | — | — | (47,247) | (47,247) |
| Other expense, net | — | — | — | — | — | — | 425 | 425 |
| Income from operations before income taxes | 7,723 | 2,109 | 21,692 | 6,443 | 11,218 | (8,179) | (6,465) | 34,541 |
| Income tax benefit | — | — | — | — | — | — | (13,560) | (13,560) |
| Net income | $ 7,723 | $ 2,109 | $ 21,692 | $ 6,443 | $11,218 | $(8,179) | $ 7,095 | $ 48,101 |

Progress Energy Florida and the California Independent System Operator ("CAISO") provide for 78.0% and 15.9%, respectively, of total consolidated revenues for the year ended December 31, 2010, 71.1% and 17.3%, respectively, of total consolidated revenues for the year ended December 31, 2009 and 75.1% and 18.1%, respectively, of total consolidated revenues for the year ended December 31, 2008. Progress Energy Florida purchases electricity from Auburndale and Lake, and the CAISO makes payments to Path 15.

## 17. Related party transactions

During 2010, we made a short-term $22.8 million loan to Idaho Wind (see Note 3(e)) to provide temporary funding for construction of the project until a portion of the project-level construction financing is completed. Member loans will be paid down with a combination of excess proceeds from the federal stimulus cash grant after repaying the cash grant facility, funds from a third closing for additional debt, and project cash flow. The federal stimulus grant is expected in the second quarter of 2011 and a third closing is expected by the end of the year. The outstanding loans bear interest at a prime rate plus 10% (13.25% as December 31, 2010). As of March 18, 2011, $5.1 million of the loan has been repaid.

Prior to December 31, 2009, Atlantic Power was managed by Atlantic Power Management, LLC (the "Manager"), which was owned by two private equity funds managed by Arclight Capital Partners, LLC ("ArcLight"). On December 31, 2009, we terminated our management agreements with the Manager and have agreed to pay the ArcLight funds an aggregate of $15 million, to be satisfied by a payment of $6 million that was made at the termination date, and additional payments of $5 million, $3 million and $1 million on the respective first, second and third anniversaries of the termination date. We recorded the remaining liability associated with the termination fee at its estimated fair value of

**17. Related party transactions (Continued)**

$3.7 million at December 31, 2010. The contract termination liability is being accreted to the final amounts due over the term of these payments.

**18. Common stock and normal course issuer bid**

On October 20, 2010, we completed a public offering of 6,029,000 common shares, including 784,000 common shares issued pursuant to the exercise in full of the underwriters' over-allotment option, at a price of $13.35 per common share. We received net proceeds from the common share offering, after deducting the underwriters discounts and expenses, of approximately $75.3 million.

On November 27, 2009 the shareholders approved the conversion from the IPS structure to a traditional common share structure. Each IPS has been exchanged for one new common share of and each old common share not forming part of an IPS was exchanged for approximately 0.44 of a new common share.

In 2008, we approved a normal course issuer bid to purchase up to four million IPSs, representing approximately 8% of Atlantic Power's public float at the same time. As of December 31, 2009 and 2008, we acquired 481,600 and 558,620 IPSs at an average price of Cdn$8.42 and Cdn$8.78, respectively, under the terms of our existing normal course issuer bid. As of December 31, 2009, we have acquired a cumulative total of 1,040,220 IPSs at an average price of Cdn$8.61 since the inception of the issuer bid in July 2008. We paid the market price at the time of acquisition for any IPSs purchased through the facilities of the Toronto Stock Exchange, and all IPSs acquired under the bid have been cancelled. The issuer bid expired on July 24, 2009.

**19. Commitments and contingencies**

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

From time to time, Atlantic Power, its subsidiaries and the projects are parties to disputes and litigation that arise in the normal course of business. We assess our exposure to these matters and record estimated loss contingencies when a loss is likely and can be reasonably estimated. There are no matters pending as of December 31, 2010 which are expected to have a material adverse impact on our financial position or results of operations.

## 20. Unaudited selected quarterly financial data

Unaudited selected quarterly financial data is as follows:

| | Quarter Ended | | | |
|---|---|---|---|---|
| | 2010 | | | |
| (In millions, except per share data) | December 31, | September 30, | June 30, | March 31, |
| Project revenue | $46,092 | $54,039 | $47,904 | $47,221 |
| Project income | 14,840 | 7,634 | 15,541 | 3,864 |
| Net income (loss) attributable to Atlantic Power Corporation | 1,304 | (438) | 1,445 | (6,063) |
| Weighted average number of common shares outstanding—basic | 65,388 | 60,511 | 60,481 | 60,404 |
| Net income (loss) per weighted average common share—basic | $ 0.02 | $ (0.01) | $ 0.02 | $ (0.10) |
| Weighted average number of common shares outstanding—diluted | 80,966 | 72,598 | 72,363 | 72,271 |
| Net income (loss) per weighted average common share—diluted* | $ 0.02 | $ (0.01) | $ 0.02 | $ (0.10) |

* The calculation excludes potentially dilutive shares from convertible debentures because their impact would be anti-dilutive.

| | Quarter Ended | | | |
|---|---|---|---|---|
| | 2009 | | | |
| (In millions, except per share data) | December 31, | September 30, | June 30, | March 31, |
| Project revenue | $ 44,356 | $ 44,857 | $ 44,270 | $46,034 |
| Project income | 17,976 | 4,444 | 11,461 | 14,534 |
| Net (loss) income | (16,197) | (15,803) | (10,729) | 4,243 |
| Weighted average number of common shares outstanding—basic | 60,475 | 60,518 | 60,600 | 60,941 |
| Net (loss) income per weighted average common share—basic | $ (0.27) | $ (0.26) | $ (0.18) | $ 0.07 |
| Weighted average number of common shares outstanding—diluted | 66,797 | 65,812 | 65,978 | 66,088 |
| Net (loss) income per weighted average common share—diluted* | $ (0.27) | $ (0.26) | $ (0.18) | $ 0.07 |

* The calculation excludes potentially dilutive shares from convertible debentures and LTIP notional units because their impact would be anti-dilutive.

## 21. Subsequent events

On February 28, 2011, we entered into a purchase and sale agreement with a third party for the purchase of our lessor interest in the Topsham project. Closing of the transaction is expected to occur in the second quarter of 2011.

**22. United States and Canadian accounting policy differences**

In accordance with Canadian securities legislation, issuers that file reports with the Securities and Exchange Commission in the United States are allowed to file financial statements under United States GAAP to meet their continuous disclosure obligations in Canada. We have included a reconciliation highlighting the material differences between our consolidated financial statements prepared in accordance with United States GAAP compared to our consolidated financial statements prepared in accordance with Canadian GAAP below.

*Consolidated reconciliation of net income and shareholders' equity*

Net income (loss) and shareholders' equity reconciled to Canadian GAAP are as follows:

| | 2010 | 2009 |
|---|---|---|
| Net income (loss), based on United States GAAP | $ (3,855) | $(38,486) |
| Changes in fair value of power purchase agreement, net of tax(1) | (12,704) | 15,899 |
| Projects accounted for under the cost method of accounting, net of tax(2) | 3,393 | 4,314 |
| Net income (loss), based on Canadian GAAP | $(13,166) | $(18,273) |

| | December 31, | |
|---|---|---|
| | 2010 | 2009 |
| Shareholders' equity, based on United States GAAP | $433,376 | $414,117 |
| Adjusted for cumulative effect of US/Canadian differences | 56,254 | 65,566 |
| Shareholders' equity, based on Canadian GAAP | $489,630 | $479,683 |

(1) The accounting standard under United States GAAP for derivative instruments provides an exemption for PPAs that contain both a capacity payment and an energy component which, if certain criteria are met, qualifies the PPA for the normal purchases and normal sales treatment. A similar exemption does not exist under Canadian GAAP and accordingly, a PPA with a capacity payment, a minimum or specified quantity of energy and delivery into a liquid market is subject to fair value accounting. Our PPA at the Chambers project meets the normal purchases and normal sales exemption under United States GAAP and is not subject to fair value accounting.

(2) We follow a standard under United States GAAP that establishes a presumption of significant influence with a low threshold of ownership in investments in limited partnerships and requires accounting under the equity method. Our investments in the Selkirk and Gregory projects are accounted for under the cost method for Canadian GAAP because there is not a different threshold for ownership interest in limited partnerships and we do not exercise significant influence over the operating and financial policies of these investments.

**22. United States and Canadian accounting policy differences (Continued)**

*Earnings per share*

| | 2010 | 2009 |
|---|---|---|
| Earnings per share under Canadian GAAP | | |
| Loss from continuing operations per share—basic | $(0.21) | $(0.40) |
| Income from discontinued operations per share—basic | — | 0.10 |
| Net loss per share—basic | $(0.21) | $(0.30) |
| Loss from continuing operations per share—diluted | $(0.21) | $(0.40) |
| Income from discontinued operations per share—diluted | — | 0.10 |
| Net loss per share—diluted | $(0.21) | $(0.30) |

*Condensed consolidated balance sheet*

| | December 31, 2010 (Canadian GAAP) | December 31, 2009 (Canadian GAAP) |
|---|---|---|
| Assets | | |
| Current assets | $ 196,773 | $ 149,340 |
| Equity investments in unconsolidated affiliates[(1)] | 98,766 | 61,037 |
| Other long-term assets | 847,974 | 827,175 |
| Total assets | $1,143,513 | $1,037,552 |
| Liabilities and Shareholders' Equity | | |
| Current liabilities | $ 83,729 | $ 77,471 |
| Other non-current liabilities[(2)] | 570,154 | 480,398 |
| Shareholders' equity: | | |
| Common shares | 625,495 | 541,304 |
| Accumulated other comprehensive income (loss) | 255 | (859) |
| Retained deficit | (139,627) | (60,762) |
| Noncontrolling interest | 3,507 | — |
| Total shareholders' equity | 489,630 | 479,683 |
| Total liabilities and shareholders' equity | $1,143,513 | $1,037,552 |

(1) We follow a standard under United States GAAP that requires the equity method of accounting for our investments with 50% or less ownership interest in which we do not have a controlling interest. Under Canadian GAAP, our share of each of the assets, liabilities, revenues and expenses of our investments that are subject to joint control is proportionately consolidated.

(2) Under United States GAAP, deferred financing costs related to long-term debt and convertible debentures is presented as a component of other long-term assets. Under Canadian GAAP, deferred financing costs related to long-term debt and convertible debentures is presented as a reduction of the carrying amount of long-term debt and convertible debentures. The balance of deferred financing costs included in other non-current liabilities for December 31, 2010 and 2009 was $16.7 million and $5.5 million, respectively.

**22. United States and Canadian accounting policy differences (Continued)**

*Condensed consolidated statement of operations*

| | 2010 (Canadian GAAP) | 2009 (Canadian GAAP) |
|---|---|---|
| Project Income | | |
| Project revenue | $309,773 | $288,281 |
| Project expenses | 233,575 | 224,572 |
| Project other expenses | (65,739) | (32,237) |
| | 10,459 | 31,472 |
| Administration and other expenses, net | 26,791 | 102,560 |
| Loss from operations before income taxes | (16,332) | (71,088) |
| Income tax expense (benefit) | (3,166) | (46,551) |
| Income from continuing operations | (13,166) | (24,537) |
| Less: Net loss attributable to noncontrolling interest | (103) | — |
| Loss from discontinued operations, net of tax | — | 6,264 |
| Net income (loss) attributable to Atlantic Power Corporation | $(13,063) | $(18,273) |

*Condensed consolidated statement of cash flows*

| | 2010 (Canadian GAAP) | 2009 (Canadian GAAP) |
|---|---|---|
| Cash provided by operating activities of continuing operations | $ 98,542 | $ 62,019 |
| Cash provided by operating activities of discontinued operations | — | 470 |
| | 98,542 | 62,489 |
| Cash used in investing activities of continuing operations | (147,734) | (71,773) |
| Cash used in investing activities of discontinued operations | — | (1,853) |
| | (147,734) | (73,626) |
| Cash provided by (used in) financing activities of continuing operations | 44,072 | (6,226) |
| Cash provided by financing activities of discontinued operations | — | 29,300 |
| | 44,072 | 23,074 |
| Increase (decrease) in cash and cash equivalents | (5,120) | 11,937 |
| Cash and cash equivalents, beginning of period | 54,503 | 42,566 |
| Cash and cash equivalents, end of period | $ 49,383 | $ 54,503 |

**22. United States and Canadian accounting policy differences (Continued)**

**NOTES TO RECONCILIATION TO CANADIAN GENERALLY ACCEPTED ACCOUNTING PRINCIPLES**

**A) Joint venture investments**

We account for six entities under proportionate consolidation as of December 31, 2010:

| Entity name | Proportion consolidated |
|---|---|
| Badger Creek Limited | 50.0% |
| Orlando Cogen, LP | 50.0% |
| Topsham Hydro Assets | 50.0% |
| Onondaga Renewables, LLC | 50.0% |
| Koma Kulshan Associates | 49.8% |
| Chambers Cogen, LP | 40.0% |

The following summarizes the balance sheets at December 31, 2010 and 2009, and operating results and distributions paid to for the years ended December 31, 2010 and 2009 for our proportionate share of the six joint venture entities:

| | 2010 | 2009 |
|---|---|---|
| Assets | | |
| Current assets | $ 77,390 | $ 48,070 |
| Non-Current assets | 265,239 | 341,630 |
| | $342,629 | $389,700 |
| Liabilities | | |
| Current liabilities | $ 22,367 | $ 25,443 |
| Non-Current liabilities | 66,474 | 114,153 |
| | $ 88,841 | $139,596 |
| Operating results | | |
| Revenue | $114,517 | $107,762 |
| Net loss | (18,503) | (194) |
| Distributions paid from joint ventures | $ 15,411 | $ 18,373 |

**B) Capital management**

Our overall objectives in capital management are to optimize the cost of capital related to existing assets and growth opportunities, as well as maintaining a prudent capital structure whose risk characteristics do not jeopardize realization of long term value from our assets. Our capital structure consists of non-recourse project-level debt, a credit facility, convertible debentures and common stock.

We currently pay a monthly dividend at an annual rate of Cdn$1.094 per common share. We have historically raised debt capital at the operating or project-level at lower interest rates than what would be required on corporate-level debt. These financings are structured as non-recourse to us and an adverse impact to debt at any single project has no influence on debt at other projects, and in virtually all cases the principal fully amortizes before the primary PPA expires.

**22. United States and Canadian accounting policy differences (Continued)**

In some cases we may raise an additional tranche of non-recourse, fully-amortizing debt at a holding company that owns the project equity. The appropriate degree of total operating leverage is a function of assessing the potential volatility of projected cash flows to maintain a low probability that a temporary project operating issue could cause our equity in the project to be at risk before curing the problem. There are also lender safeguards in these financings such as debt service and major maintenance reserves that help mitigate impacts to our cash flow from temporary project operating issues.

The credit facility is designed for several purposes: 1) to support letters of credit covering certain contingent performance risks at several projects, 2) to provide corporate liquidity in the case of significant unexpected temporary interruption or reductions to operating cash flows, and 3) to contribute to bridge financing for potential acquisitions. The credit facility has a total capacity of $100 million with two equal bank participants.

Acquisition bridge facilities have also historically been placed at this senior corporate level with the revolving credit facility lenders. The capital structure is periodically reviewed by our management and Board of Directors to determine whether changes are required to meet the objectives outlined above. Other than the capital management decisions discussed, there were no other changes in our approach to capital management during the period. Neither we, nor any of our subsidiaries are subject to externally imposed capital requirements.

**C) Financial risk management**

We have exposure to market risk, credit risk and liquidity risk from our use of financial instruments:

*Market risk*

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

We are exposed to changes in foreign currency exchange rates because it earns all of its income in U.S. dollars but has substantial obligations in Canadian dollars. We manage this risk through the use of foreign currency forward contracts and, where possible, establishing any new obligations in U.S. dollars instead of Canadian dollars.

The impact of changes in interest rates do not have a significant impact on cash payments that are required on our debt instruments as approximately 86% of our debt, including non-recourse project-level debt and our share of debt at unconsolidated projects, bears interest at fixed rates.

The debt obligations at our proportionately consolidated Chambers project bears interest at variable rates. Exposure to changes in interest rates related to this variable rate debt has been partially mitigated through the use of interest rate swaps. After considering the impact of interest rate swaps, a hypothetical change in the average interest rate of 100 basis points would change annual interest costs, including interest at proportionately consolidated projects, by approximately $0.9 million.

**22. United States and Canadian accounting policy differences (Continued)**

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

*Credit risk*

Credit risk is the risk of financial loss if a customer or counterparty to a financial instrument fails to meet its contractual obligations. Our maximum exposure to credit risk is the carrying value of financial assets included in the consolidated balance sheet. Our exposure to credit losses from accounts receivable at its projects is mitigated by the fact that most projects sell power under long-term contracts with investment-grade utilities and other counterparties. We do not have a history of credit losses related to long-term contracts at the projects and no significant amounts are currently past due. Our risk of credit loss on other financial instruments is managed by conducting business with financial institutions that have strong credit ratings.

*Liquidity risk*

Liquidity risk is the risk that we will not be able to meet its financial obligations as they become due. We believe that future cash flows from operating activities and access to additional liquidity through capital and bank markets will be adequate to meet its financial obligations.

**D) Recently adopted Canadian accounting pronouncements**

*a) Goodwill and intangible assets*

Effective January 1, 2009, we adopted CICA Handbook Section 3064, "Goodwill and Intangible Assets", which replaces Section 3062, "Goodwill and Other Intangible Assets", and Section 3450, "Research and Development Costs" and establishes standards for the recognition, measurement and disclosure of goodwill and intangible assets. The provisions relating to the definition and initial recognition of intangible assets, including internally generated intangible assets, are equivalent to the corresponding provisions of International Accounting Standard IAS 38, "Intangible Assets". The adoption of this standard did not impact our consolidated financial statements.

*b) Business combinations*

On January 1, 2010, we adopted CICA Handbook Section 1582, "Business Combinations". This section establishes standards for the accounting of business combinations, and states that all assets and liabilities of an acquired business will be recorded at fair value. Obligations for contingent consideration and contingencies will also be recorded at fair value at the acquisition date. The standard also states that acquisition related costs will be expensed as incurred, that restructuring charges will be expensed in periods after the acquisition date and that non-controlling interests should be measured at fair value at the date of acquisition. This standard is to be applied prospectively to business combinations with acquisition dates on or after January 1, 2010. This new standard was applied to the step-up acquisition of Rollcast and the acquisition of Cadillac.

**22. United States and Canadian accounting policy differences (Continued)**

*c) Consolidated financial statements*

On January 1, 2010, we adopted CICA Handbook Section 1601, "Consolidated Financial Statements". The new standard replaces Section 1600, "Consolidated Financial Statements". This Section carries forward existing Canadian guidance for preparing consolidated financial statements other than guidance for non-controlling interests. The adoption of this standard did not have a material impact on our consolidated financial statements.

*d) Non-controlling interests*

On January 1, 2010, we adopted CICA Handbook Section 1602, "Non-Controlling Interests". The new standard establishes standards for the accounting of non-controlling interests of a subsidiary in the preparation of consolidated financial statements subsequent to a business combination. The adoption of this standard did not have a material impact on our consolidated financial statements.

**E) Recent Canadian accounting pronouncements announced but not yet effective**

*International Financial Reporting Standards (IFRS)*

The Canadian Accounting Standards Board has set January 1, 2011 as the date that IFRS will replace Canadian GAAP for publicly accountable enterprises, which includes Canadian reporting issuers. Financial reporting under IFRS differs from Canadian GAAP in a number of respects, some of which are significant. We report in U.S. GAAP and are not planning to adopt IFRS as we will no longer be required to provide a reconciliation to Canadian GAAP beyond December 31, 2010.

## VALUATION AND QUALIFYING ACCOUNTS
## FOR THE YEARS ENDED DECEMBER 31, 2010, 2009 AND 2008
## (in thousands)

| | Balance at Beginning of Period | Charged to Costs and Expenses | Charged to Other Accounts | Deductions | Balance at End of Period |
|---|---|---|---|---|---|
| **Income tax valuation allowance, deducted from deferred tax assets:** | | | | | |
| Year ended December 31, 2010 | $67,131 | $ 12,289 | $— | $— | $79,420 |
| Year ended December 31, 2009 | 45,126 | 22,005 | — | — | 67,131 |
| Year ended December 31, 2008 | 82,237 | (37,111) | — | — | 45,126 |

**Chambers Cogeneration Limited Partnership**

Consolidated Financial Statements

December 31, 2010 and 2009

**Chambers Cogeneration Limited Partnership Index**
**December 31, 2010 and 2009**

**Report of Independent Auditors**

To the Board of Control of
Chambers Cogeneration Limited Partnership:

In our opinion, the accompanying consolidated balance sheet and the related consolidated statement of operations, of changes in partners' capital and comprehensive income, and of cash flows present fairly, in all material respects, the financial position of Chambers Cogeneration Limited Partnership and its subsidiaries at December 31, 2010, and the results of their operations and their cash flows for the year then ended in conformity with accounting principles generally accepted in the United States of America. These financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on these financial statements based on our audits. We conducted our audits of these statements 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 examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements, assessing the accounting principles used and significant estimates made by management, and evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

/s/ PricewaterhouseCoopers LLP

Philadelphia, Pennsylvania
March 16, 2011

## Chambers Cogeneration Limited Partnership

## Consolidated Balance Sheets

## December 31, 2010 and 2009

| (in thousands of dollars) | 2010 | 2009 |
|---|---|---|
| **Assets** | | |
| Current assets | | |
| Cash and cash equivalents | $ 53 | $ 99 |
| Restricted cash | 8,292 | 6,305 |
| Accounts receivable | 15,195 | 11,965 |
| Inventory | 8,201 | 7,235 |
| Emission allowances | — | 2,540 |
| Other assets | 469 | 1,162 |
| Total current assets | 32,210 | 29,306 |
| Construction in Progress | 9 | — |
| Property and equipment, net of accumulated depreciation of $189,541 and $181,368, respectively | 350,800 | 358,875 |
| Deferred financing costs, net of accumulated amortization of $5,182 and $4,957 respectively | 1,648 | 1,873 |
| Other assets | — | 80 |
| Total assets | $384,667 | $390,134 |
| **Liabilities and Partners' Capital** | | |
| Current liabilities | | |
| Current portion of long-term debt | $ 28,235 | $ 27,628 |
| Accounts payable | 4,670 | 5,406 |
| Due to affiliates | 1,887 | 1,784 |
| Accrued liabilities | 1,822 | 1,655 |
| Interest rate swap | 4,470 | 5,851 |
| Total current liabilities | 41,084 | 42,324 |
| Long-term debt | 159,376 | 187,611 |
| Interest rate swap | 3,243 | 4,842 |
| Asset retirement obligation | 2,107 | 1,998 |
| Total liabilities | 205,810 | 236,775 |
| Commitments and contingencies | | |
| Partners' capital | | |
| General partners | 178,549 | 93,687 |
| Limited partner | 1,804 | 62,456 |
| Accumulated other comprehensive loss | (1,496) | (2,784) |
| Total partners' capital | 178,857 | 153,359 |
| Total liabilities and partners' capital | $384,667 | $390,134 |

The accompanying notes are an integral part of these consolidated financial statements.

**Chambers Cogeneration Limited Partnership**

**Consolidated Statements of Operations**

**Years Ended December 31, 2010 and 2009**

| (in thousands of dollars) | 2010 | 2009 |
|---|---|---|
| **Operating revenues** | | |
| Energy | $ 62,440 | $ 52,727 |
| Capacity | 59,996 | 59,665 |
| Steam | 16,443 | 14,266 |
| Total operating revenues | 138,879 | 126,658 |
| **Operating expenses** | | |
| Fuel | 59,129 | 53,625 |
| Operations and maintenance | 25,910 | 34,322 |
| General and administrative | 5,824 | 4,975 |
| Depreciation | 8,173 | 8,278 |
| Loss on disposal of assets | — | 1,030 |
| Total operating expenses | 99,036 | 102,230 |
| Operating income | 39,843 | 24,428 |
| **Other income (expense)** | | |
| Interest income | 1 | 3 |
| Miscellaneous income | 133 | — |
| Unrealized gain on interest rate swaps | 2,980 | 5,599 |
| Interest expense | (11,747) | (15,614) |
| Net income | $ 31,210 | $ 14,416 |

The accompanying notes are an integral part of these consolidated financial statements.

**Chambers Cogeneration Limited Partnership**

**Consolidated Statements of Changes in Partners' Capital and Comprehensive Income**

**Years Ended December 31, 2010 and 2009**

| (in thousands of dollars) | General Partners | Limited Partner | Comprehensive Income | Accumulated Other Comprehensive Loss | Total |
|---|---|---|---|---|---|
| **Partners' capital at December 31, 2008** | $ 86,747 | $ 57,830 | | $(4,570) | $140,007 |
| Net income | 8,650 | 5,766 | $14,416 | | 14,416 |
| Amortization of previously deferred loss on interest rate swap agreement | | | 1,786 | 1,786 | 1,786 |
| Total comprehensive income | 8,650 | 5,766 | $16,202 | | |
| Capital distributions | (1,710) | (1,140) | | — | (2,850) |
| **Partners' capital at December 31, 2009** | $ 93,687 | $ 62,456 | | $(2,784) | $153,359 |
| Conversion of partnership interest | $ 64,652 | $(64,652) | | | |
| Net income | 27,140 | 4,070 | $31,210 | | 31,210 |
| Amortization of previously deferred loss on interest rate swap agreement | | | 1,288 | 1,288 | 1,288 |
| Total comprehensive income | 27,140 | 4,070 | $32,498 | | |
| Capital distributions | (6,930) | (70) | | | (7,000) |
| **Partners' capital at December 31, 2010** | $178,549 | $ 1,804 | | $(1,496) | $178,857 |

The accompanying notes are an integral part of these consolidated financial statements.

**Chambers Cogeneration Limited Partnership**

**Consolidated Statements of Cash Flows**

**Years Ended December 31, 2010 and 2009**

| (in thousands of dollars) | 2010 | 2009 |
|---|---|---|
| **Cash flows from operating activities** | | |
| Net income | $ 31,210 | $ 14,416 |
| Noncash items included in net income: | | |
| Amortization of deferred interest rate swap losses | 1,288 | 1,786 |
| Unrealized gain on interest rate swaps | (2,980) | (5,599) |
| Depreciation | 8,173 | 8,278 |
| Amortization of deferred financing costs | 225 | 244 |
| Accretion of asset retirement obligation | 109 | 103 |
| Loss on disposal of assets | — | 1,030 |
| Changes in operating assets and liabilities: | | |
| Accounts receivable | (3,230) | 2,709 |
| Inventory | (966) | 1,116 |
| Emission allowances | 2,540 | (2,540) |
| Other assets | 773 | 1,864 |
| Accounts payable | (736) | (1,265) |
| Due to affiliates | 103 | (444) |
| Accrued liabilities | 160 | (740) |
| Net cash provided by operating activities | 36,669 | 20,958 |
| **Cash flows from investing activities** | | |
| (Decrease) increase in restricted cash | (1,987) | 7,347 |
| Proceeds from the sale of assets | — | 32 |
| Capital expenditures | (100) | (1,602) |
| Net cash (used in) provided by investing activities | (2,087) | 5,777 |
| **Cash flows from financing activities** | | |
| Repayments of long-term debt | (27,628) | (23,920) |
| Capital distributions | (7,000) | (2,850) |
| Cash used in financing activities | (34,628) | (26,770) |
| Net decrease in cash and cash equivalents | (46) | (35) |
| **Cash and cash equivalents** | | |
| Beginning of period | 99 | 134 |
| End of period | $ 53 | $ 99 |
| **Supplemental disclosure of cash flow information** | | |
| Cash paid for interest | $ 10,312 | $ 13,586 |

The accompanying notes are an integral part of these consolidated financial statements.

**Chambers Cogeneration Limited Partnership**

**Notes to Consolidated Financial Statements**

**December 31, 2010 and 2009**

## 1. Organization and Business

Chambers Cogeneration Limited Partnership (the "Partnership") is a Delaware limited partnership formed on August 17, 1988. The general partners are Peregrine Power, LLC ("Peregrine"), a California limited liability company, and Cogentrix/Carneys Point, LLC ("Cogentrix/Carneys"), a Delaware limited liability company. Cogentrix/Carneys and Peregrine were each wholly-owned indirect subsidiaries of Cogentrix Energy, LLC ("CELLC"). In November 2007, CELLC transferred 100% of its indirect equity interest in Peregrine and Cogentrix/Carneys to Calypso Energy Holdings, LLC ("Calypso") then a wholly-owned subsidiary of CELLC. Following such transfer on November 14, 2007, CELLC sold an 80% equity interest in Calypso to EIF Calypso, LLC ("EIF"), a limited liability company owned by one or more private equity funds managed by EIF Management, LLC (collectively the "Calypso Transaction"). CELLC holds a 20% equity interest in Calypso and a 12% indirect interest in the Partnership. Epsilon Power ("Epsilon"), a wholly-owned indirect subsidiary of Atlantic Power Corporation holds a 40% interest in the Partnership. In May 2010, Epsilon converted 39% of their 40% limited partnership interest to a general partnership interest.

The Partnership was formed to construct, own and operate a 262-megawatt ("MW") coal-fired cogeneration station (the "Facility") at DuPont's Chambers Works chemical complex in Carneys Point, New Jersey. The Facility produces energy for sale to Atlantic City Electric Company ("AE"), and energy and process steam to E.I. DuPont de Nemours & Company ("DuPont") for use in its industrial operations. The Facility achieved final completion and commercial operations in 1994.

In December 2008, the Partnership submitted an application to PJM Interconnection ("PJM") to increase the Facility's capacity rating from 225 MW to 240 MW. On April 28, 2009, the Partnership received notice from PJM that the capacity interconnection rights assigned to the Facility have been increased to 240 MW. The Facility currently sells excess energy under a separate power sales agreement (Note 10).

The net income and losses of the Partnership are allocated to Peregrine, Cogentrix/Carneys and Epsilon (collectively, the "Partners") based on the following ownership percentages:

| | |
|---|---|
| Peregrine | 50% |
| Cogentrix/Carneys | 10% |
| Epsilon (39% general partnership, 1% limited partnership) | 40% |

All distributions other than liquidating distributions are made based on the Partners' percentage interests, as shown above, in accordance with the Partnership documents and at such times and in such amounts as the Board of Control of the Partnership determines.

### Carneys Point Generating Company, L.P.

The Partnership has a lease agreement with Carneys Point Generating Company, L.P. ("CPGC"), which is equally owned by Topaz Power, LLC ("Topaz") and by Garnet Power, LLC (Garnet"), both of which were wholly-owned direct subsidiaries of Power Services Company, LLC ("PSC"), an indirect wholly-owned subsidiary of CELLC. In November 2007, CELLC transferred 100% of its ownership interest in Topaz and Garnet to Calypso in connection with the Calypso Transaction. CPGC leases the facility and subleases the site from the Partnership. In addition, certain contracts and agreements related to the Partnership have been assigned to CPGC by the Partnership. The lease commenced on

### 1. Organization and Business (Continued)

September 20, 1994 and has a 24-year term. CPGC's operations have been established to effectively break-even under the lease agreement.

### 2. Summary of Significant Accounting Policies

#### Basis of Presentation

On January 1, 2010, the Partnership adopted an accounting standards update that changes when and how to determine, or re-determine, whether an entity is a variable interest entity ("VIE"), which could require consolidation. In addition, the accounting standards update replaces the quantitative approach for determining who has a controlling financial interest in a VIE with a qualitative approach and requires ongoing assessments of whether an entity is the primary beneficiary of a VIE.

The Partnership is required to consolidate any entities that they control. In most cases, control can be determined based on majority ownership or voting interests. However, for certain entities, control is difficult to discern based on ownership or voting interests alone. These entities are referred to as VIE's. A VIE is an entity that does not have sufficient equity at risk to finance its activities without additional subordinated financial support from other parties, or whose equity investors lack any characteristics of a controlling financial interest. An enterprise has a controlling financial interest if it has the obligation to absorb expected losses or receive expected gains that could potentially be significant to a VIE and the power to direct activities that are most significant to a VIE's economic performance. An enterprise that has a controlling financial interest is known as the VIE's primary beneficiary and is required to consolidate the VIE. The Partnership reassesses its determination of whether the Partnership is the primary beneficiary of a VIE at each reporting date or if there are changes in facts and circumstances that could potentially alter the Partnership's assessment.

The Partnership has determined that CPGC is a VIE of the Partnership primarily due to its lease arrangements with CPGC. The Partnership has determined that it has the power to direct the activities that most significantly impact CPGC's economic performance, and therefore the Partnership consolidates CPGC into its financial statements. All material intercompany transactions have been eliminated.

#### Use of Estimates

The preparation of consolidated financial statements in conformity with accounting principles generally accepted in the United States of America ("GAAP") requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities and disclosure of contingent liabilities as of the date of the consolidated financial statements and the reported amounts of revenues and expenses during the reporting period. Actual results could differ from those estimates.

#### Cash and Cash Equivalents

Cash and cash equivalents consist of short-term, highly liquid investments with original maturities of three months or less.

**2. Summary of Significant Accounting Policies (Continued)**

**Restricted Cash**

Restricted cash includes both cash and cash equivalents that are held in accounts restricted for operations, debt service, major maintenance and other specifically designated accounts under a disbursement agreement. All restricted accounts are classified as current assets.

**Inventory**

Fuel is valued using the average cost method and includes the fuel contract purchase price as well as the transportation and related costs incurred to deliver the fuel to the Facility (Note 3).

Spare parts are recorded at the lower of average cost or market and consist of Facility equipment components and supplies required to facilitate maintenance activities. Spare parts are classified as current in the accompanying consolidated balance sheets (Note 3).

The Partnership performs periodic assessments to determine the existence of obsolete, slow-moving and unusable inventory and records necessary provisions to reduce such inventories to net realizable value.

**Emission Allowances**

Emission allowances are valued under the weighted average costing method subject to the lower of cost or market principle. In applying the lower of cost or market principle, a reduction in the carrying value is not recognized so long as the Partnership will recover/pass-through the cost in its operating margin.

The historical cost of emission allowances is calculated as follows:

- Granted from regulatory body—emission allowances obtained via grants are not assigned any value by the Partnership as their cost is zero.
- Acquired as part of an acquisition—emission allowances are recorded at fair value as of the acquisition date, subject to pro rata reduction if overall purchase price is less than the entity's fair value.
- Purchased from third parties—emission allowances that are transferable and can be purchased or sold in the normal course of business are recorded at cost.

**Derivative Contracts**

In accordance with guidance on accounting for derivative instruments and hedging activities all derivatives should be recognized at fair value. Derivatives or any portion thereof, that are not designated as, and effective as, hedges must be adjusted to fair value through earnings. Derivative contracts are classified as either assets or liabilities on the consolidated balance sheets. Certain contracts that require physical delivery may qualify for and be designated as normal purchases/normal sales. Such contracts are accounted for on an accrual basis. The Partnership's interest rate swap agreement (Notes 5 and 8) and power purchase agreement ("PPA") (Note 10) meet the definition of a derivative. The Partnership's PPA qualifies for, and the Partnership has elected, the normal purchases and normal sales exception and accordingly accounts for the PPA on an accrual basis.

**2. Summary of Significant Accounting Policies (Continued)**

The Partnership engages in activities to manage risks associated with changes in interest rates. The Partnership has entered into swap agreements to reduce exposure to interest rate fluctuations on certain debt commitments (Note 5). These agreements were designated and qualified as cash flow hedging instruments through December 31, 2004. The Partnership discontinued applying cash flow hedge accounting on January 1, 2005. The balance of accumulated other comprehensive loss, as of December 31, 2004, is amortized as interest expense in the accompanying consolidated statements of operations in accordance with the originally forecasted interest payments schedule through the expiration of the interest rate swaps on March 31, 2014.

**Fair Value Measurements**

The Partnership uses a fair value hierarchy that prioritizes the inputs to valuation techniques used to measure fair value. The hierarchy gives the highest priority to unadjusted quoted prices in active markets for identical assets or liabilities (level 1 measurements) and the lowest priority to unobservable inputs (level 3 measurements). The three levels of the fair value hierarchy are described below:

- Level 1: Observable inputs such as quoted prices (unadjusted) in active markets for identical assets or liabilities.
- Level 2: Inputs other than quoted prices that are observable for the asset or liability, either directly or indirectly. These include quoted prices for similar assets or liabilities in active markets and quoted prices for identical or similar assets or liabilities in markets that are not active.
- Level 3: Unobservable inputs that reflect the reporting entity's own assumptions.

A financial instrument's level within the fair value hierarchy is based on the lowest level of any input that is significant to the fair value measurement (Note 8). As of December 31, 2010 and 2009, the Partnership does not have any non-financial assets or liabilities remeasured at fair value on a recurring basis

**Property and Equipment**

Property and equipment are recorded at cost, net of accumulated depreciation. Expenditures for major additions and improvements are capitalized and minor replacements, maintenance, and repairs are charged to expense as incurred. When property and equipment are retired or otherwise disposed of, the cost and accumulated depreciation are removed from the accounts and any resulting gain or loss is included in the results of operations for the respective period. Depreciation is provided over the estimated useful life ("EUL") of the related assets using the straight-line method (Note 4).

The Partnership's depreciation is based on the Facility being considered a single property unit. Certain components within the Facility will require replacement or overhaul several times over its estimated life. Costs associated with overhauls are recorded as an expense in the period incurred. However, in instances where a replacement of a Facility component is significant and the Partnership can reasonably estimate the original cost of the component being replaced, the Partnership will write-off the replaced component and capitalize the cost of the replacement. The component will be depreciated over the lesser of the EUL of the component or the remaining useful life of the Facility.

**2. Summary of Significant Accounting Policies (Continued)**

The Partnership reviews the carrying value of property and equipment for impairment whenever events and circumstances indicate that the carrying value of an asset may not be recoverable from the estimated future cash flows expected to result from its use and eventual disposition. In cases where undiscounted expected future cash flows are less than the carrying value, an impairment loss is recognized equal to an amount by which the carrying value exceeds the fair value of assets. The factors considered by management in performing this assessment include current operating results, trends and prospects, the manner in which the property is used, and the effects of obsolescence, demand, competition, and other economic factors.

**Deferred Financing Costs**

Deferred financing costs, which consist of the costs incurred to obtain financing, are deferred and amortized into interest expense in the accompanying consolidated statements of operations using the effective interest method over the term of the related financing (Note 5).

**Asset Retirement Obligations**

Asset retirement obligations, including those conditioned on future events, are recorded at fair value in the period in which they are incurred, if a reasonable estimate of fair value can be made. The associated asset retirement costs are capitalized as part of the carrying amount of the related long-lived asset in the same period. In each subsequent period, the liability is accreted to its present value and the capitalized cost is depreciated over the EUL of the long-lived asset. If the asset retirement obligation is settled for other than the carrying amount of the liability, the Partnership recognizes a gain or loss on settlement. The Partnership records at fair value all reclamation costs the Partnership would incur to perform environmental clean-up of land under lease to the Partnership.

**Income Taxes**

As a partnership, the income tax effects accrue directly to the partners, and each partner is individually responsible for its share of the combined income or loss. Accordingly, no provision has been made for income taxes.

**Revenue Recognition**

Revenues from the sale of energy and steam are recorded based on monthly output delivered as specified under contractual terms or current market conditions and are recorded on a gross basis on the accompanying consolidated statements of operations as energy and steam revenues, respectively, with the associated costs recorded in operating expenses.

**Reclassifications**

Certain reclassifications have been made to the prior year's consolidated financial statements to conform to the current year presentation. These reclassifications had no effect on the previously reported results of operations or partners' capital.

## 2. Summary of Significant Accounting Policies (Continued)

### Subsequent Events

The Partnership evaluated subsequent events through March 16, 2011.

### Recent Accounting Pronouncements

Effective July 1, 2009 the Partnership adopted the Accounting Standards Codification ("ASC") issued by the FASB. The ASC does not change GAAP, but instead takes the numerous individual accounting pronouncements that previously constituted GAAP and reorganizes them into approximately 90 accounting topics, which are then broken down into subtopics, sections and paragraphs. The intent is to simplify user access to authoritative GAAP by providing all of the guidance related to a particular topic in one place. ASC supersedes all previously existing non-Security and Exchange Commission or non-grandfathered accounting and reporting standards. The adoption of ASC did not have any impact on the Partnership's consolidated financial statements.

## 3. Inventory

Inventory consisted of the following as of December 31:

| (in thousands of dollars) | 2010 | 2009 |
|---|---|---|
| Coal | $3,727 | $3,142 |
| Fuel oil | 335 | 376 |
| Lime | 120 | 95 |
| Spare parts | 4,019 | 3,622 |
| | 8,201 | 7,235 |

## 4. Property and Equipment

Property and equipment consisted of the following components as of December 31:

| (in thousands of dollars) | 2010 | 2009 |
|---|---|---|
| Facility | $ 537,273 | $ 537,175 |
| Other equipment | 3,068 | 3,068 |
| Construction in progress | 9 | — |
| | 540,350 | 540,243 |
| Less: Accumulated depreciation | (189,541) | (181,368) |
| | $ 350,809 | $ 358,875 |

The EUL for significant property and equipment categories are as follows:

| | |
|---|---|
| Facility | 60 years |
| Other equipment | 5 to 60 years |

## 5. Long-Term Debt

Long-term debt consisted of the following as of December 31:

| (in thousands of dollars) Description | As of December 31, 2010 Commitment Amount | Due Date | Balance Outstanding | For the Year Ended December 31, 2010 Interest Expense | Letter of Credit Fees |
|---|---|---|---|---|---|
| Bonds payable(1)(6) | $100,000 | 7/1/21 | $100,000 | $ 352 | N/A |
| Credit agreement | | | | | |
| Term loans(3)(6) | 87,611 | 3/31/14 | 87,611 | 1,695 | N/A |
| Bond letter of credit(4)(6)(7) | 102,466 | 12/31/12 | — | N/A | 1,480 |
| Debt service reserve letter of credit(5)(6)(7) | 22,750 | 12/31/12 | — | N/A | 386 |
| | | | 187,611 | | |
| Less: Current portion | | | 28,235 | | |
| | | | $159,376 | | |

| (in thousands of dollars) Description | As of December 31, 2009 Commitment Amount | Due Date | Balance Outstanding | For the Year Ended December 31, 2009 Interest Expense | Letter of Credit Fees |
|---|---|---|---|---|---|
| Bonds payable(1)(6) | $100,000 | 7/1/21 | $100,000 | $1,795 | N/A |
| Loan payable(2) | — | 6/10/09 | — | 3 | N/A |
| Credit agreement | | | | | |
| Term loans(3)(6) | 115,239 | 3/31/14 | 115,239 | 2,856 | N/A |
| Bond letter of credit(4)(6)(7) | 102,466 | 12/31/12 | — | N/A | 1,495 |
| Debt service reserve letter of credit(5)(6)(7) | 22,750 | 12/31/12 | — | N/A | 389 |
| | | | 215,239 | | |
| Less: Current portion | | | 27,628 | | |
| | | | $187,611 | | |

(1) The bonds are collateralized by an irrevocable letter of credit and provide for interest at variable rates. The weighted-average interest rates on the bonds were 0.36% and 1.79% for the years ended December 31, 2010 and 2009, respectively. Remarketing fees paid to the remarketing agent were approximately $100,000 in both 2010 and 2009. These fees are included in interest expense in the accompanying consolidated statements of operations.

(2) Loan payable is collateralized by equipment. The term is 60-months commencing July 2004 with interest fixed at 6.25%.

(3) The term loans accrue interest at the applicable London Interbank Offered Rate ("LIBOR"), plus an applicable margin (1.25% at December 31, 2010 and December 31, 2009). The weighted average interest rates on the term loan were 1.62% and 2.16% for 2010 and 2009, respectively.

**5. Long-Term Debt (Continued)**

(4) The letter of credit fee for 2010 and 2009 was 1.25%. In addition, the facility provides for a fronting fee of 0.175% on the stated amount which is included in interest expense in the accompanying consolidated statements of operations.

(5) The letter of credit fee for 2010 and 2009 was 1.5%. In addition, the facility provided for a fronting fee of 0.175% on the stated amount which is included in interest expense in the accompanying consolidated statements of operations.

(6) All bonds, loans and credit facilities are collateralized by the assets of the Facility and the real estate covered by the ground lease (Note 1) and are nonrecourse to the Partners.

(7) As of December 31, 2010 and 2009, there were no amounts available under the letter of credit commitments.

Accrued interest payable of $3,000 and $81,000 is included in accrued liabilities in the consolidated balance sheets as of December 31, 2010 and 2009, respectively.

Future minimum principal payments as of December 31, 2010 are as follows:

| (in thousands of dollars) | |
|---|---|
| 2011 | 28,235 |
| 2012 | 30,439 |
| 2013 | 26,957 |
| 2014 | 1,980 |
| 2015 | — |
| Thereafter | 100,000 |
| | $187,611 |

In connection with the various agreements discussed above, certain financial covenants must be met and reported on an annual basis. The Partnership was in compliance with all debt covenants at December 31, 2010.

**Interest Rate Swap Agreements**

The Partnership is a party to two amortizing interest rate swap agreements with notional amounts outstanding aggregating $87,611,000 at December 31, 2010 and expiring on various dates through March 31, 2014. Swap payments related to the agreements covering the variable rate bank debt are made based on the spread between 5.81% (weighted average of all agreements as of December 31, 2010) and LIBOR multiplied by the notional amounts outstanding. Net amounts paid to the counterparties were approximately $6,170,000 and $6,871,000 in 2010 and 2009, respectively. These amounts were recorded as interest expense in the accompanying consolidated statements of operations.

### 6. Operating Leases

The Partnership leases certain equipment under non-cancelable operating leases expiring at various dates through 2024. For the years ended December 31, 2010 and 2009, the Partnership incurred lease expense of approximately $208,000 and $219,000, respectively, which is included in operations and maintenance expense and general and administrative expense in the accompanying consolidated statements of operations.

Future minimum lease payments, as of December 31, 2010, are as follows:

| (in thousands of dollars) | |
|---|---|
| 2011 | 201 |
| 2012 | 199 |
| 2013 | 197 |
| 2014 | 197 |
| 2015 | 196 |
| Thereafter | 1,166 |
| | $2,156 |

### 7. Payment in Lieu of Taxes

In January 1991, the Partnership entered into a Payment in Lieu of Taxes ("PILOT") agreement with the Township of Carneys Point, a municipal corporation of the state of New Jersey, which exempts the Partnership from certain property taxes. The agreement commenced on January 1, 1994, and will terminate on December 31, 2033. PILOT payments are paid annually and are expensed as incurred over the term of the agreement. Property taxes are due and paid quarterly and are deducted from the annual PILOT payments made. The Partnership expensed approximately $2,700,000 and $2,600,000 related to the PILOT which is included in general and administrative in the accompanying consolidated statements of operations for the years ended December 31, 2010 and 2009, respectively.

As of December 31, 2010, future payments remaining under the PILOT are as follows:

| (in thousands of dollars) | |
|---|---|
| 2011 | 2,800 |
| 2012 | 3,000 |
| 2013 | 3,400 |
| 2014 | 3,700 |
| 2015 | 3,900 |
| Thereafter | 114,700 |
| | $131,500 |

### 8. Fair Value of Financial Instruments

The fair value of the Partnership's swap agreements, based upon Level 2—significant other observable inputs, is estimated to be a liability of approximately $7,713,000 and $10,693,000 as of December 31, 2010 and 2009, respectively (Notes 2 and 5). The valuation of the Partnership's swap agreements is based on widely accepted valuation techniques including discounted cash flow analyses

## 8. Fair Value of Financial Instruments (Continued)

which take into consideration among other things the contractual terms of the swap agreements, observable market based inputs when available, interest rate curves and counterparty credit risk. Judgment is required in interpreting market data to develop the estimates of fair value. Accordingly, the fair value estimates as of December 31, 2010 and 2009, are not necessarily indicative of amounts the Partnership could have realized in current markets.

The Partnership's financial instruments consist of cash and cash equivalents, restricted cash, accounts receivable, other assets, accounts payable, due to affiliates, and accrued liabilities. These instruments approximate their fair values as of December 31, 2010 and 2009 due to their short-term nature.

The fair value of the Partnership's bonds and term loans payable approximates their carrying value due to the variable nature of the interest obligations thereon.

## 9. Concentrations of Credit Risk

Credit risk is the risk of loss the Partnership would incur if counterparties fail to perform their contractual obligations. The Partnership primarily conducts business with counterparties in the energy industry. This concentration of counterparties may impact the Partnership's overall exposure to credit risk in that its counterparties may be similarly affected by changes in economic, regulatory or other conditions. The Partnership mitigates potential credit losses by dealing, where practical, with counterparties that are rated investment grade by a major credit rating agency or have a history of reliable performance within the energy industry.

The Partnership's credit risk is primarily concentrated with AE, DuPont and the Partnership's coal supplier. AE and DuPont provided 80.5% and 19.5%, respectively, of the Partnership's revenues for the year ended December 31, 2010 and accounted for approximately 78.7% and 21.3%, respectively, of the Partnership's trade accounts receivable balance at December 31, 2010. The Partnership has a coal supply contract with Consolidated Coal Company, Consolidated Pennsylvania Coal Company, Consolidated Coal Sales Company and Nineveh Coal Company (together "Consol") who are responsible for providing 100% of the Partnership's coal requirements through 2014. The Partnership's credit risk is also impacted by the credit risk associated with its issuing bank of the bond letter of credit, Dexia Credit Locale.

The Partnership is exposed to credit-related losses in the event of nonperformance by counterparties to the Partnership's interest rate swap agreements (Notes 2 and 5). The Partnership does not obtain collateral or other security to support such agreements, but continually monitors its positions with, and the credit quality of, the counterparties to such agreements.

## 10. Commitments and Contingencies

### Power Purchase Agreement

The Partnership has a power purchase agreement ("PPA") with AE for sales of the Facility's power output during a 30-year period commencing in 1994. The PPA provides AE with dispatch rights over the Facility, with a contractual minimum of the equivalent of 3,500 hours of full load operation. The pricing structure provides for both capacity and energy payments. Capacity payments are fixed over the

**10. Commitments and Contingencies (Continued)**

life of the contract. Energy payments are based on a contractual formula which is adjusted annually, as defined in the PPA, based on a utility coal index.

**Power Sales Agreement**

The Partnership has entered into a supplemental power sales agreement ("PSA") with AE which provides the Partnership self-dispatch rights for both undispatched PPA and excess energy as well as the right to market excess capacity. The pricing structure provides for both capacity and energy payments. The Partnership shares margins on the self-dispatched energy with AE based on hourly wholesale prices. Excess capacity is sold in PJM's periodic auctions and the resulting revenue is shared between the Partnership and AE. The PSA expired on December 31, 2010. The Partnership has entered into a new PSA with AE that commences January 1, 2011 and expires on December 31, 2011.

**Steam and Electricity Sales Agreement**

The Partnership has a steam and electricity sales agreement with DuPont (the "DuPont Agreement") for a 30-year period commencing in 1994. Thereafter, the agreement will remain in effect unless terminated by either party upon at least 36-months' notice. DuPont is required to purchase a minimum of 525,600,000 pounds of process steam per year and no minimum amount of electricity. The steam price is adjusted quarterly based on coal price index formulas defined in the agreement. The electricity price is also adjusted quarterly based on coal price index formulas and the AE average retail rate, as defined in the agreement. The Partnership has ongoing litigation with DuPont over electric energy payment calculation. Amounts under dispute have not been reflected in revenues in the accompanying consolidated statements of operations.

**Fly Ash Disposal Agreement**

The Partnership has an agreement with Consolidation Coal Company, Consol Pennsylvania Coal Company, Consolidation Coal Sales Company and Nineveh Coal Company, jointly ("CONSOL"), for a 20-year period commencing in 1994 for the disposal of fly ash with a minimum requirement of 130,000 tons per contract year. The Partnership does not anticipate meeting this requirement by the end of the contract year ending on March 14, 2011. Accordingly, the Partnership has accrued approximately $204,000 related to this shortage at December 31, 2010 which is included in fuel expense on the accompanying consolidated statement of operations. CONSOL transports the facilities coal ash to Pennsylvania where it is used for mine reclamation. The Pennsylvania Department of Environmental Protection ("PADEP") has recently issued revisions to the standards required for beneficial use of coal ash in the State of Pennsylvania. The facilities ash will have a difficult time meeting the new standards. The Partnership is evaluating process changes to meet the new PADEP standards as well as evaluating alternate disposal sites outside the State of Pennsylvania. The Partnership expects no material impact related to the potential changes in ash disposal.

**Reverse Osmosis Boiler Feed Water System**

The Partnership has entered into a capital lease agreement with Wells Fargo Equipment Finance, Inc ("Wells Fargo") to lease a new Reverse Osmosis Boiler Feed Water System ("RO") to be designed, fabricated, and installed by Western Reserve Water Systems in 2011. The capital lease is for a term of

### 10. Commitments and Contingencies (Continued)

60 months to commence upon final acceptance of the Partnership of the installed RO. At the end of the lease term, the Partnership will have the option to purchase the RO for $1.

#### Other

The Partnership experiences routine litigation in the normal course of business. Management is of the opinion that none of this routine litigation will have a material adverse effect on the Partnership's consolidated financial position or results of operations.

### 11. Related Parties

#### Operations and Maintenance Agreement

The Partnership is party to an Operations and Maintenance Agreement ("O&M Agreement") with US Operating Services Company, LLC ("USOSC"), a wholly-owned subsidiary of Calypso, for the operation and maintenance ("O&M") of the Carneys Point Project. During the third quarter 2010, ownership of USOSC was acquired by Calypso from CELLC. The O&M Agreement expires on April 1, 2014. Thereafter, the O&M agreement will be automatically renewed for periods of five-years until terminated by either party with 12-months prior notice. Compensation to OSC under the agreement includes (i) an annual base fee, of which a portion is subordinate to debt service and certain other costs, (ii) certain earned fees and bonuses based on the Facility's performance and (iii) reimbursement for certain costs, including payroll, supplies, spare parts, equipment, certain taxes, licensing fees, insurance and indirect costs expressed as a percentage of payroll and personnel costs. The fees are adjusted annually by a measure of inflation as defined in the agreement. If targeted Facility performance is not reached on a monthly basis, OSC may be required to pay liquidated damages to the Partnership. The Partnership incurred related expense of approximately $9,771,000 and $9,857,000 which is recorded in operations and maintenance in the consolidated statements of operations during the years ended December 31, 2010 and 2009, respectively. As of December 31, 2010 and 2009, the Partnership owed OSC $1,844,000 and $1,649,000, respectively, under the O&M Agreement, which is included in due to affiliates in the accompanying consolidated balance sheets. Under the terms of the agreement, approximately $350,000 and $287,000 of the amounts owed at December 31, 2010 and 2009, respectively, is subordinate to the debt service for the Partnership's bonds payable and term loans. In addition, approximately $549,000 in other costs had been advanced to OSC at December 31, 2009 and are included in other current assets in the accompanying consolidated balance sheets.

USOSC is party to a Technical Services Agreement ("TSA') with Power Services Company, LLC ("PSC"), a wholly-owned subsidiary of Calypso, for services to assist in the day-to-day O&M of the Carneys Point Project. During the third quarter 2010, ownership of PSC was acquired by Calypso from CELLC.

PSC and NAES Corporation ("NAES"), an independent third-party O&M provider, are parties to a subcontract ("NAES Agreement") for NAES to perform all tasks commercially and reasonably necessary to operate, maintain and manage the Company, including administering, managing, monitoring and performing all of USOSC's obligations and responsibilities of the O&M agreement between USOSC and the Partnership. The NAES agreement expires on August 23, 2015.

**11. Related Parties (Continued)**

**Management Services Agreement**

The Partnership has a Management Services Agreement ("MSA") with PSC to provide day-to-day management and administration services to the Carneys Point Project through September 20, 2018. PSC and Power Plant Management Services, LLC ("PPMS"), an independent third party management services provider, are parties to a subcontract formalized under a Project Management and Administrative Services Agreement ("PMAS") for the Carneys Point Project. The initial term of the PMAS agreement expires on August 23, 2015. The initial term automatically extends for successive two year periods or, if the Facility MSA is scheduled to terminate or expire pursuant to its own terms prior to the expiration of any two year period, a shorter period equal to the time remaining under the Facility MSA unless either party notifies the other party at least three months prior to expiration of the then existing term. Under the PMAS, PPMS provides overall project management, administrative, and related support services as may be necessary to the Partnership and oversees the execution of the NAES agreement on behalf of the Partnership. Compensation to PSC under the agreement includes a monthly fee of $50,000, and PMAS pass-through costs. Payments to PSC of $1,731,000 and $1,860,000 are included in operations and maintenance in the consolidated statements of operations in 2010 and 2009, respectively. As of December 31, 2010 and 2009, the Partnership owed PSC approximately $50,000 and $135,000, respectively, which is included in due to affiliates in the accompanying consolidated balance sheets. Under the terms of the agreement, $50,000 of the amounts owed for each of 2010 and 2009 is subordinate to debt service for the Partnership's bonds payable and term loans.

* * * * *

**Exhibit 31.1**

I, Barry E. Welch, certify that:

1. I have reviewed this Annual Report on Form 10-K of Atlantic Power Corporation;

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

4. The registrant's other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) for the registrant and have:

   a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

   b) [Paragraph omitted in accordance with Exchange Act Rule 13a-14(a)];

   c) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

   d) Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and

5. The registrant's other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):

   a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

   b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: March 18, 2011

/s/ BARRY E. WELCH

Barry E. Welch
*President and Chief Executive Officer*

**Exhibit 31.2**

I, Patrick J. Welch, certify that:

1. I have reviewed this Annual Report on Form 10-K of Atlantic Power Corporation;

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

4. The registrant's other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) for the registrant and have:

   a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

   b) [Paragraph omitted in accordance with Exchange Act Rule 13a-14(a)];

   c) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

   d) Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and

5. The registrant's other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):

   a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

   b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: March 18, 2011

/s/ PATRICK J. WELCH

Patrick J. Welch
*Chief Financial Officer*

**Exhibit 32.1**

**CERTIFICATION PURSUANT TO
18 U.S.C. SECTION 1350,
AS ADOPTED PURSUANT TO SECTION 906 OF THE
SARBANES-OXLEY ACT OF 2002**

The undersigned officer of Atlantic Power Corporation (the "Company") hereby certifies to his knowledge that the Company's Annual Report on Form 10-K for the year ended December 31, 2010 (the "Report"), as filed with the Securities and Exchange Commission on the date hereof, fully complies with the requirements of Section 13(a) or 15(d), as applicable, of the Securities Exchange Act of 1934, as amended, and that the information contained in the Report fairly presents, in all material respects, the financial condition and results of operations of the Company. This certification shall not be deemed "filed" for any purpose, nor shall it be deemed to be incorporated by reference into any filing under the Securities Act of 1933 or the Securities Exchange Act of 1934 regardless of any general incorporation language in such filing.

Date: March 18, 2011

/s/ BARRY E. WELCH

Barry E. Welch
*President and Chief Executive Officer*

**Exhibit 32.2**

**CERTIFICATION PURSUANT TO
18 U.S.C. SECTION 1350,
AS ADOPTED PURSUANT TO SECTION 906 OF THE
SARBANES-OXLEY ACT OF 2002**

The undersigned officer of Atlantic Power Corporation (the "Company") hereby certifies to his knowledge that the Company's Annual Report on Form 10-K for the year ended December 31, 2010 (the "Report"), as filed with the Securities and Exchange Commission on the date hereof, fully complies with the requirements of Section 13(a) or 15(d), as applicable, of the Securities Exchange Act of 1934, as amended, and that the information contained in the Report fairly presents, in all material respects, the financial condition and results of operations of the Company. This certification shall not be deemed "filed" for any purpose, nor shall it be deemed to be incorporated by reference into any filing under the Securities Act of 1933 or the Securities Exchange Act of 1934 regardless of any general incorporation language in such filing.

Date: March 18, 2011

/s/ PATRICK J. WELCH

Patrick J. Welch
*Chief Financial Officer*

AtlanticPower Corporation

# Board of Directors

**R. Foster Duncan**
Cincinnati, Ohio
Mr. Duncan is a Managing Partner of SAIL Capital Partners, a cleantech venture capital firm.

**Irving Gerstein**
Toronto, Ontario
Chairman of the Board
Senator Gerstein is a member of the Senate of Canada, and is currently a Director of Economic Investment Trust Limited, Medical Facilities Corporation and Student Transportation Inc.

**Holli Nichols**
Houston, Texas
Ms. Nichols is a Managing Director at SCF Partners, a private equity investor.

**John McNeil**
Toronto, Ontario
Mr. McNeil is President of BDR North America Inc., an energy consulting firm.

**Barry Welch**
Boston, Massachusetts
Mr. Welch is President and CEO of Atlantic Power Corporation.

**Ken Hartwick**
Toronto, Ontario
Chairman of the Audit Committee
Mr. Hartwick is President and CEO and a director of Just Energy, an integrated retailer of commodity products that is listed on the TSX.

**Atlantic Power Corporation Directors**
From left to right: R. Foster Duncan, Irving Gerstein, Holli Nichols, John McNeil, Barry Welch, Ken Hartwick

# Invest in Power

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Corporation