Invest in Power

Atlantic Power Corporation *2009 Annual Report*

AtlanticPower
Corporation

Atlantic Power Corporation

www.atlanticpower.com

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Investment Highlights

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ATTRACTIVE CASH FLOW FROM LARGE DIVERSIFIED POWER PORTFOLIO

- 807 net MWs of power generation from 12 facilities
- 84-mile 500kv transmission line in California
- Investment grade customers under medium to long-term contracts
- Fuel price pass through mechanisms protect operating margins

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PROVEN EXECUTION ON ACQUISITIONS AND ORGANIC GROWTH

- Six acquisitions since IPO, including two at existing projects
- Three distribution increases since IPO
- Numerous project initiatives to enhance cash flows and reduce risk
- Late stage development opportunities include six biomass projects

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STABLE DIVIDENDS

- Ability to maintain current dividend level into 2015 with no acquisitions
- Approximately 95% of portfolio's net MW contracted through 2013
- US/Cdn currency hedge through 2013
- More than 90% of interest rate exposure fixed

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HIGHLY EXPERIENCED MANAGEMENT TEAM AND PARTNERS

- Significant experience in the independent power industry
- Proven acquisition, financing and operational expertise
- Partners have significant knowledge and investments in power sector
- Projects managed by experienced operators

CORPORATE PROFILE Atlantic Power Corporation is an independent power producer that owns interests in a diversified fleet of power generation and transmission projects located in the United States. Atlantic Power's objectives are to maintain the stability of dividends to its shareholders and to increase the long term value of the Company by enhancing the performance of its existing assets and by making accretive acquisitions. The Company's common shares are listed on the Toronto Stock Exchange under the symbol ATP.

Invest in Power

2009 Highlights

- Project distributions at top end of guidance for the year — 87% payout ratio
- Successful conversion to common share structure generates significant benefits
- Process on track for dual listing on New York Stock Exchange by mid-year
- Internalization of management further aligns company stakeholders
- Acquired 60% of Rollcast, Inc. — developer of five biomass plants in the southeast U.S.
- Construction agreement and financing arranged for Rollcast's first 50MW biomass project
- Issued Cdn$86.25 million in 6.25% Convertible Debentures
- Retired remaining Cdn$40.7 million of 11% Subordinated Notes
- Completed sale of Stockton and Mid-Georgia projects

Atlantic Power's Management Team
From left to right: Paul Rapisarda, Managing Director, Asset Management & Acquisitions; Barry Welch, President and Chief Executive Officer; and Patrick Welch, Chief Financial Officer and Corporate Secretary.

Report to Shareholders

We had a number of significant accomplishments in 2009: exceeding the high end of our project distributions guidance, converting to a common share corporation with a much stronger balance sheet, rationalizing our project portfolio, paying down debt and raising low-cost capital. These achievements, along with our inclusion in the TSX Composite Index and our upcoming dual listing on the New York Stock Exchange, position us especially well to make further accretive acquisitions while continuing to provide stable and sustainable dividends to our shareholders.

Key Benefits from New Common Share Structure

In November 2009, we completed our conversion to a more traditional common share structure. While issuing Income Participating Securities ("IPSs") made sense at the time of our initial public offering in 2004, the structure was complex and had become an impediment to cost-effectively financing our growth. The conversion was approved by a nearly unanimous shareholder vote and brought a number of key benefits to the Company, enhancing our ability to execute our growth strategy and creating increased value for shareholders over the long term.

First, we believe the conversion has broadened our base of potential investors and enhanced trading liquidity. By eliminating the intricacies associated with the IPS structure, we will reduce the costs and complexity of raising new capital. The common share structure also makes it feasible to consider acquisitions using our stock as currency.

Second, the new structure allowed us to apply for a listing on the New York Stock Exchange, which we expect to complete by the end of the second quarter of 2010. We believe a U.S. listing will further broaden our investor base, provide enhanced liquidity for current investors and further reduce our cost of capital.

Third, the conversion eliminated the refinancing risk associated with the scheduled maturity in 2016 of the subordinated note portion of our IPSs and significantly reduced our leverage. The strengthened balance sheet enhances our flexibility to finance growth going forward.

Finally, by maintaining the same level of cash distributions to our shareholders, the conversion to a structure paying all qualified common share dividends substantially increases after-tax yields for taxable investors in both Canada and the United States.

Other Accomplishments

A number of other achievements during and subsequent to the year-end position us for solid and sustainable performance in the years ahead.

We took a number of positive steps to rationalize our portfolio, selling two of our power-producing assets. First, we received an unsolicited offer for our 50% interest in the Mid-Georgia Project and sold it for an after-tax gain of $15.8 million. Historically, Mid-Georgia had provided minimal Earnings before Interest, Taxes, Depreciation and Amortization ("EBITDA") and was not expected to make cash distributions for the next several years. Proceeds from the disposition represent capital raised at an attractive discount rate that will be used to finance future growth. We also sold our 50% interest in the 55 MW Stockton Project for a nominal cash payment. After a thorough review of plans to convert this small coal-fired plant in California to biomass, we made the decision not to invest significant new capital given the risks involved. While we recorded a small book loss, a tax loss of approximately $12 million will be available to shelter future taxable income.

In December 2009, we completed an offering of 6.25% convertible subordinated debentures for total gross proceeds of Cdn$86.25 million. An accretive use for a portion of the proceeds was to retire the remaining Cdn$40.7 million of 11% subordinated notes, with the balance available to fund future growth initiatives.

Effective December 31, 2009, we terminated the Company's management agreements with two private equity funds managed by ArcLight Capital Partners. This is consistent with recent industry trends and our goal of superior governance practices, and we continue to maintain a strong working relationship with ArcLight. An initial payment of $6 million was made, with additional payments of $5 million, $3 million and $1 million to be made on the respective first, second and third anniversaries of the termination. The Company hired all employees of the manager, and entered into new employment agreements with its officers. The internalization of all functions within Atlantic Power fully aligns the interests of management with all shareholders, and future growth initiatives will no longer be burdened by incentive fee payments.

Finally, in March 2010, Atlantic Power's common shares were included in the S&P/TSX Composite Index, raising our profile and enhancing trading liquidity for our investors.

Operating and Financial Performance

Our operating and financial performance in 2009 met our expectations and exceeded the high end of our guidance for annual project distributions. The change in Project Adjusted EBITDA in 2009 compared to the prior year was due to a number of factors, some non-recurring, and others the result of acquisitions and dispositions.

In addition to the reduction in distributions received from the Projects in 2009, there was a $6 million payment made in December related to the termination of our management agreements with ArcLight Capital Partners. As a result of these factors, Cash Flow Available for Distribution decreased by $29.2 million in 2009 compared to the prior year, resulting in a payout ratio of 87% for the year ended December 31, 2009.

All of these factors were anticipated in our forecast for the year. Importantly, we remain confident we can maintain our current level of cash dividends to shareholders into 2015 even if we assume no positive benefits from future acquisitions or internal growth initiatives.

Renewable Energy Initiatives

To provide significant growth opportunities and further diversify our project portfolio, we have made investments in renewable energy projects. In total, these six development-stage opportunities represent a potential of 290 MW if they all proceed to construction. While these projects will take some time to finish developing and construct, they represent a long-term complement to our broader acquisition strategy. Substantial incentives included in the American Recovery and Reinvestment Act of 2009 significantly enhance the economic value of several of these potential investments.

In March 2009, we paid $3 million for a 40% equity interest in Rollcast Energy, Inc., a developer of biomass power plants in the southeast United States. In March and April 2010, we invested an additional $2 million to increase our ownership interest to 60%. Our ownership gives us the option to invest in Rollcast's first five 50 MW projects. During the second quarter of 2010, Rollcast executed an engagement letter and term sheet with two banks to co-arrange debt financing and also entered into a construction agreement for its first 50 MW Project in Barnesville, Georgia.

Also during 2009, we transferred our remaining net assets of the retired Onondaga Cogeneration Project into a new 50/50 joint venture. We are working with an experienced partner to redevelop the site into a 35 to 40 MW biomass power plant. The design, development and permitting process is progressing well.

Looking Ahead

For 2010, we expect to receive distributions from our Projects in the range of $70 million to $77 million which, including corporate-level expense projections, will result in an estimated payout ratio of approximately 100% for the year.

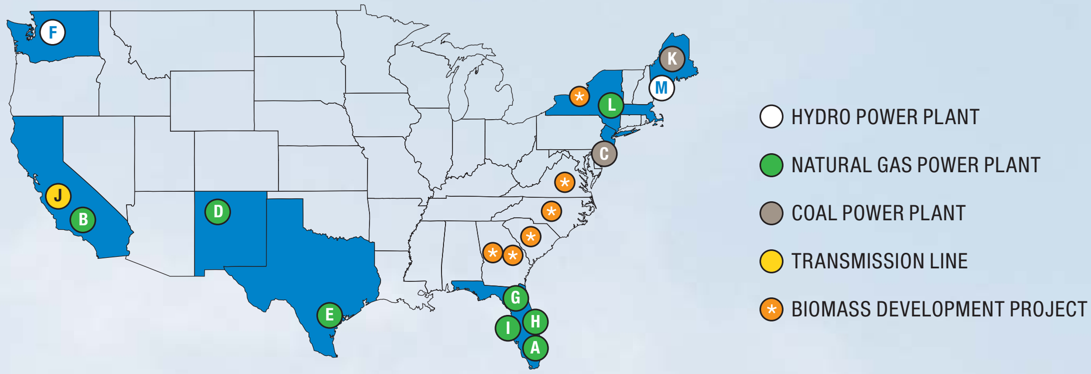
In 2011, we expect overall levels of cash flow and the payout ratio to be generally consistent with 2010. Higher project distributions and a slightly lower payment in 2011 under the management agreement termination are expected to be offset by the non-recurrence of a $7 to $9 million cash tax refund anticipated in 2010. Looking ahead to 2012, still higher distributions from our projects are expected to increase operating cash flow and reduce the payout ratio significantly compared to the two prior years.

When we determine that our operating margins may be exposed to commodity price fluctuations, we assess whether hedging programs can mitigate the risk. For example, we have now mitigated approximately 80% of the exposure through 2013 to changes in natural gas prices at the Lake and Auburndale Projects by entering into natural gas swaps that effectively fix the price we pay for specific quantities of natural gas.

All of these factors have been considered in our reaffirmed guidance that we could maintain dividends at current levels into 2015 even if we assume no positive benefits from organic growth or acquisitions. Activity levels and the quality of potential acquisitions have improved, consistent with strengthened credit markets, and we are confident we will make further accretive additions to our portfolio in the coming quarters.

We would like to thank all of our employees and partners for making 2009 an active and successful year for Atlantic Power. We also thank our shareholders for their continued support, and we look ahead with confidence in our ability to generate further growth in the years ahead.

Barry Welch
President and Chief Executive Officer



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	100.0%	155
B	Badger Creek	Bakersfield CA	Natural Gas	46	50.0%	23
C	Chambers	Carney's Point NJ	Coal	262	40.0%	105
D	Delta-Person	Albuquerque NM	Natural Gas	132	40.0%	53
E	Gregory	Corpus Christi TX	Natural Gas	400	17.1%	68
F	Koma Kulshan	Concrete, WA	Hydro	13	49.8%	6
G	Lake	Umatilla FL	Natural Gas	121	100.0%	121
H	Orlando	Orlando FL	Natural Gas	129	50.0%	65
I	Pasco	Tampa FL	Natural Gas	121	100.0%	121
J	Path 15	California	Transmission	N/A	100.0%	N/A
K	Rumford	Rumford ME	Coal/Biomass	85	23.5%	20
L	Selkirk	Bethlehem NY	Natural Gas	345	18.5%	64
M	Topsham	Topsham ME	Hydro	14	50.0%	7

Management's Discussion and Analysis

OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS

The following management's discussion and analysis ("MD&A") of financial condition and results of operations should be read in conjunction with the audited consolidated financial statements of Atlantic Power Corporation ("Atlantic Power" or the "Company") for the year ended December 31, 2009. All dollar amounts in this MD&A are in thousands of U.S. dollars, unless otherwise stated. The financial statements have been prepared in accordance with Canadian generally accepted accounting principles ("GAAP"). Information contained in this MD&A is based on information available to management as of March 29, 2010.

FORWARD-LOOKING STATEMENTS

Certain statements in this MD&A may constitute "forward-looking statements", which reflect the expectations of the Company regarding future growth, results of operations, performance and business prospects and opportunities of Atlantic Power and the Projects (as defined below). Examples of such statements include, but are not limited to, statements with respect to the following:

- the expected opportunities for accretive acquisitions;
- the intention of the Company to seek a listing of the new common shares on the New York Stock Exchange ("NYSE") in the second quarter of 2010;
- the expected favorable tax treatment for holders of Income Participating Securities ("IPSs") when receiving dividends on the new common shares subsequent to the Common Share Conversion (as compared to receiving distributions on the IPSs);
- the expected increase in the Company's base of potential investors as a result of the Common Share Conversion and NYSE listing;
- the expectation that the Company's cash on hand and projected future cash flows from existing Projects will be adequate to meet the current level of cash distributions to shareholders into 2015 without additional acquisitions or organic growth;
- the amount of distributions expected to be received from the Projects for the full year 2010;
- estimated net cash tax refund in 2010;
- levels of cash flow and payout ratios estimated for 2010, 2011 and 2012;
- the Company's current forecast of expected annual cash distributions from the Lake and Auburndale Projects through 2012; and
- the expected resumption of distributions from the Chambers Project in 2010 and the Selkirk Project in 2011.

Such forward-looking statements reflect current expectations regarding future events and operating performance and are made only as of the date of this MD&A. Such forward-looking statements are based on a number of assumptions which may prove to be incorrect, including but not limited to the assumption that the Projects will operate and perform in accordance with the Company's expectations. Forward-looking statements involve significant risks and uncertainties, should not be read as guarantees of future performance or results, and are not necessarily accurate indications of whether or not, or the times at or by which, such performance or results will be achieved. In addition to the assumption described above, reference should also be made to the factors discussed under "Risk Factors" in the Company's Annual Information Form dated March 29, 2010. Although the forward-looking statements contained in this MD&A are based upon what are believed to be reasonable assumptions, investors cannot be assured that actual results will be consistent with these forward-looking statements, and the differences may be material. These forward-looking statements are made as of the date of this MD&A and, except as expressly required by applicable law, the Company assumes no obligation to update or revise them to reflect new events or circumstances. The financial outlook information contained in this MD&A is presented to provide readers with guidance on the cash distributions expected to be received by the Company from its Project interests and to give readers a better understanding of the Company's ability to fund its current level of distributions into the future. Readers are cautioned that such information may not be appropriate for other purposes.

Copies of financial data and other publicly filed documents, including the Company's Annual Information Form, are available on SEDAR at www.sedar.com under "Atlantic Power Corporation" or on the Company's website at www.atlanticpower.com.

OVERVIEW

As of March 29, 2010, the Company has 60,404,093 common shares, Cdn$60 million principal amount of 6.50% convertible secured debentures due October 31, 2014 (the "2006 Debentures"), and Cdn$86.25 million principal amount of 6.25% convertible debentures due March 15, 2017 (the "2009 Debentures" and together with the 2006 Debentures, the "Debentures") outstanding. The 2006 Debentures and the 2009 Debentures are convertible at any time, at the option of the holder, into 80.6452 and 76.9231 common shares per Cdn$1,000 principal amount of Debentures, respectively, representing a conversion price of Cdn$12.40 and Cdn$13.00, respectively, per common share. Holders of common shares receive a monthly dividend at a current annual rate of Cdn$1.094 per common share.

Prior to December 31, 2009, the Company was managed by Atlantic Power Management, LLC (the "Manager"), which was owned by two private equity funds (the "ArcLight Funds") managed by ArcLight Capital Partners, LLC. On December 31, 2009, the Company terminated its management agreements with the Manager, and has agreed to pay the ArcLight Funds an aggregate of $15 million, to be satisfied by a payment of $6 million that was made on 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. In connection with the termination of the management agreements, the Company hired all of the employees of the Manager and entered into new employment agreements with the officers of the Manager. The internalization of the Company's management function further aligns management and the Company's shareholders, further enhancing the Company's strong corporate governance practices.

As of December 31, 2009, the Company owned interests in 12 power generating facilities in the United States and a transmission line in California (collectively, the "Projects" and individually, a "Project"). The Company sold its interests in Stockton Cogeneration Company L.P. ("Stockton") and Mid-Georgia Cogeneration L.P. ("Mid-Georgia") in November 2009 and their results are presented as discontinued operations in this MD&A. The generating Projects have a combined total power generating capacity of approximately 1,823 megawatts ("MW"). The Company's net interests in the Projects represented approximately 808 MW of capacity as of December 31, 2009.

Most of the generating Projects sell their power under medium to long-term power purchase agreements ("PPAs") to investment-grade utilities or other power purchasers. These agreements are typically structured to stabilize cash flows by: (1) providing on average approximately half of the electricity revenues via steady capacity or tolling payments generally designed to provide a return of and on capital and to cover fixed costs regardless of how much electricity the plant is called upon to produce, provided that the plant meets an availability requirement; and (2) generally passing changes in the generating Projects' fuel costs on to the power purchasers. As a result, variations in the portfolio's cash flow resulting from changes in the amount of power generated, spot market electricity prices and fuel price changes are significantly mitigated.

The Path 15 transmission line is a United States Federal Energy Regulatory Commission ("FERC") regulated asset with a 30-year regulatory life through 2034. Its annual revenue requirement is established by FERC every three years and is collected monthly by the California Independent System Operator ("CAISO") from utilities in the state. The revenue requirement does not vary with changes in power prices or line usage, and the Project has virtually no technical or operating risks.

The Company's objectives are to maintain the stability and sustainability of dividends to its shareholders and to increase the long-term value of the Company. To achieve these objectives, the Company focuses on enhancing the operation of the existing Projects by improving facility performance, increasing output and efficiency, optimizing contracts and managing other Project risks. In addition, the Company has a focused growth strategy that includes consolidating interests in Projects where it already holds an ownership interest, and making accretive acquisitions with a primary focus on the electric power industry in the United States and Canada.

Management believes that opportunities for accretive acquisitions will be available based on a number of factors, including continued long-term electricity demand growth, along with retirement of older plants and the corresponding need for new power plants, continued liquidity in the secondary market for ownership interests in power-related assets, and superior access to potential growth transactions through the Company's industry contacts. Competitors for these opportunities include private equity or infrastructure funds, power income funds and other sources of capital.

The most significant economic factors affecting the Company's performance are changes in energy commodity prices, interest rates, credit spreads and the currency exchange rate between the U.S. dollar and the Canadian dollar. See "Outlook" in this MD&A for further details regarding Projects that have exposure to commodity price risk. Approximately 90% of the Company's existing debt, including its share of the project-level debt associated with cost and equity method investments, either bears interest at a fixed rate or is economically hedged through the use of interest rate swaps. However, interest rates and credit spreads could affect valuations of assets the Company may be attempting to buy or sell. All of the Company's operating cash flow is earned in U.S. dollars, while dividends to shareholders and interest payments on the Debentures are denominated in Canadian dollars. See "Financial Instruments" in this MD&A for more information about currency exchange rate impacts and the Company's strategy for managing this risk, including the hedging of the current levels of dividends and interest payments on the Debentures at fixed rates through 2013.

RECENT DEVELOPMENTS

On December 17, 2009, the Company 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$75 million. On December 24, 2009, the underwriters exercised their over-allotment option in full to purchase an additional Cdn$11.25 million aggregate principal amount of the 2009 Debentures. 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 2009 Debentures, representing a conversion price of Cdn$13.00 per common share.

On November 24, 2009, the Company's shareholders approved the conversion from the Company's Income Participating Security ("IPS") structure to a traditional common share structure (the "Common Share Conversion"). The Company plans to maintain its current business strategy and its current dividend levels. Each IPS has been exchanged for one new common share of the Company and each old common share of the Company that did not form part of an IPS was exchanged for approximately 0.44 of a new common share of the Company. This transaction resulted in the extinguishment of Cdn$347,832 principal value of 11% Subordinated Notes due 2016 (the "Subordinated Notes") that previously formed a part of each IPS. A loss on the Common Share Conversion in the amount of $13,069 was recorded in interest expense within administrative and other expenses and was comprised of the write-off of unamortized deferred financing costs of $7,507, the costs associated with the Common Share Conversion of $4,704 and the write-off of the unamortized Subordinated Note premium of $858. The Company's entire monthly cash distribution of Cdn$0.0912 per IPS is now paid as a dividend on the new common shares. In addition, the Company announced its intention to list the new common shares on the New York Stock Exchange ("NYSE") in the second quarter of 2010.

On December 17, 2009, the Company exercised its call option for the remaining Cdn$40,677 principal value of Subordinated Notes at 105% of the principal amount. A loss on the redemption of these Subordinated Notes in the amount of $3,175 was recorded in interest expense within administrative and other expenses and was comprised of the write-off of unamortized deferred financing costs of $1,240 and the 5% premium paid in the amount of $1,935.

In connection with the shareholders meeting on the Common Share Conversion, a meeting of the holders of the 2006 Debentures was held at which their approval was obtained for certain amendments to the indenture governing the 2006 Debentures, including an increase in the annual interest rate from 6.25% to 6.50% and separately, an extension of the maturity date from October 2011 to October 2014. See "Liquidity and Capital Resources" in this MD&A for additional details.

During the third quarter of 2009, management reviewed the recoverability of its 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 management's assessment of the long-term economic viability of the plant after the current PPA expired on December 31, 2009. Based on this review, management determined that the carrying value of the Rumford Project was impaired and recorded a pre-tax long-lived asset impairment of $5,500 in the third quarter of 2009.

In the fourth quarter of 2009, the Company and the other limited partners in the Rumford Project settled a dispute with the general partner related to its failure to pay distributions to the limited partners in 2009. Under the terms of the settlement, the Company received $2,901 in distributions from Rumford in the fourth quarter of 2009. In addition, the general partner has agreed to purchase the interests of all the limited partners in 2010. However, the general partner is relieved of this obligation if certain conditions are met before June 30, 2010. If the general partner does purchase the limited partners' interests, the Company's share of the proceeds will be approximately $2.5 million.

The FERC issued its initial order regarding Path 15's 2008-2010 rates on February 19, 2008. That order granted approval of the Company's proposed rates and set certain other matters for hearing. On March 23, 2009, Path 15, FERC staff and the intervenors in the Project's rate case filed an uncontested settlement with the FERC. The FERC issued an order approving the settlement on August 3, 2009. The terms of the settlement allow Path 15 to continue making distributions to the Company that are consistent with management's expectations. In October 2009, Path 15 paid a refund of approximately $1.4 million, comprising the amount collected above the settlement rates since the initial order in February 2008. Independently, the final landowner litigation over right-of-way issues was resolved earlier in 2009, which resulted in approximately $6 million being released to the Company from a construction reserve account.

During the years ended December 31, 2009 and 2008, the Company acquired 481,600 and 558,620 IPSs at an average price of Cdn$8.42 and Cdn$8.78, respectively, under the terms of its normal course issuer bid. As of December 31, 2009, the Company had 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. Atlantic Power paid the market price at the time of acquisition for any IPSs purchased through the facilities of the Toronto Stock Exchange ("TSX"), and all IPSs acquired under the bid have been cancelled. The issuer bid expired on July 24, 2009. The Company does not anticipate additional share repurchases at this time.

On March 31, 2009, the Company acquired a 40% equity interest in Rollcast Energy, Inc., ("Rollcast") a North Carolina corporation. Rollcast is a developer of biomass power plants in the southeastern U.S. with five 50 MW projects in various stages of development. The investment in Rollcast gives the Company the option but not the obligation to invest equity in Rollcast's biomass power plants. Two of the development projects have secured 20-year PPAs with terms that allow for fuel cost pass-through to the utility customer. Total cash paid for the investment was $3 million and is accounted for under the equity method of accounting.

In March 2010, the Company agreed to contribute up to an additional $2.0 million to increase its 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 will be payable if Rollcast achieves certain milestones. As a result of this additional investment, the Company will begin to consolidate its investment in Rollcast beginning in the first quarter of 2010. This additional investment was contemplated at the time of the Company's original investment in Rollcast.

In March 2010, Rollcast agreed to the principal terms of a financing arrangement for its first biomass project with two banks and expects to close the financing in the second quarter of 2010.

In the first quarter of 2009, the Company transferred its remaining net assets of Onondaga Cogeneration Limited Partnership at net book value into a 50% owned joint venture, Onondaga Renewables, LLC, which is exploring redevelopment of the Project into a 35-40 MW biomass power plant. The Company proportionately consolidates its investment in Onondaga Renewables.

DISCONTINUED OPERATIONS

On November 30, 2009, the Company completed the sale of its 50% interest in the Stockton Project for a nominal cash payment. Stockton is a 55 MW coal/biomass cogeneration facility located in Stockton, California. The Project was facing significant additional capital investment requirements in order to use as much biomass fuel as possible, and historically has provided only approximately 2% of the Company's Adjusted EBITDA. The Company recorded a book loss on the sale of $2 million and generated a tax loss of approximately $12 million.

On November 24, 2009, the Company completed the sale of its 50% interest in the assets of Mid-Georgia for cash proceeds of $29.1 million. Mid-Georgia is a 308 MW dual-fuel, combined-cycle cogeneration project located in Kathleen, Georgia. The Company recorded a gain on sale of $15.8 million. Historically, Mid-Georgia has provided minimal Adjusted EBITDA and was not expected to make cash distributions to the Company for the next several years. The proceeds from the sale will be used to finance future growth.

NON-GAAP FINANCIAL MEASURES

Cash Flow Available for Distribution is not a measure recognized under GAAP and does not have a standardized meaning prescribed by GAAP and therefore may not be comparable to similar measures presented by other issuers. Management believes Cash Flow Available for Distribution is a relevant supplemental measure of the Company's ability to earn and distribute cash returns to investors. A reconciliation of net cash provided by operating activities of continuing operations to Cash Flow Available for Distribution is set out in "Cash Flow Available for Distribution" in this MD&A. Investors are cautioned that the Company may calculate this measure in a manner that is different from other companies.

Adjusted EBITDA is defined as income from continuing operations less interest, taxes, depreciation and amortization (including non-cash impairment charges) and changes in fair value of derivative instruments. 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 issuers. Management uses unaudited Adjusted EBITDA at the Projects to provide comparative information about Project performance. Investors are cautioned that the Company may calculate this measure in a manner that is different from other companies.

SELECTED FINANCIAL DATA

(in thousands of U.S. dollars, except as otherwise stated)

	Three months ended December 31			Years ended December 31		
(unaudited)	2009	2008	2007	2009	2008	2007
Project income						
Project revenue	**72,110**	81,977	68,062	**288,281**	301,572	268,182
Project expenses	**58,922**	56,252	43,579	**224,572**	205,017	169,363
Project other income (expense)	**(61,272)**	75,982	(119,361)	**(32,237)**	57,427	(211,422)
Total project income (loss)	**(48,084)**	101,707	(94,878)	**31,472**	153,982	(112,603)
Administrative and other expenses						
Management fees and administration	**17,637**	2,490	2,574	**26,028**	10,012	8,185
Interest, net	**24,267**	9,589	10,630	**55,665**	43,275	44,306
Foreign exchange loss (gain)	**(1,528)**	(27,391)	2,030	**20,506**	(44,692)	30,142
Change in fair value of Subordinated Note prepayment option	**5,430**	–	–	**106**	(27)	–
Other expenses	**327**	(42)	242	**255**	451	360
Total administrative and other expenses	**46,133**	(15,354)	15,476	**102,560**	9,019	82,993
Income (loss) from continuing operations before income taxes	**(94,217)**	117,061	(110,354)	**(71,088)**	144,963	(195,596)
Income tax expense (benefit)	**(55,486)**	26,084	(36,522)	**(46,551)**	21,224	(47,221)
Income (loss) from continuing operations	**(38,731)**	90,977	(73,832)	**(24,537)**	123,739	(148,375)
Income (loss) from discontinued operations	**9,163**	(12,056)	(411)	**6,264**	(13,051)	(830)
Net income (loss)	**(29,568)**	78,921	(74,243)	**(18,273)**	110,688	(149,205)
Basic earnings (loss) from continuing operations per share, US$	**$ (0.64)**	$ 1.49	$ (1.20)	**$ (0.40)**	$ 2.02	$ (2.41)
Basic earnings (loss) from discontinued operations per share, US$	**0.15**	(0.19)	(0.01)	**0.10**	(0.21)	(0.02)
Basic earnings per share, US$	**$ (0.49)**	$ 1.30	$ (1.21)	**$ (0.30)**	$ 1.81	$ (2.43)
Basic earnings (loss) from continuing operations per share, Cdn$ (1)	**$ (0.68)**	$ 1.81	$ (1.18)	**$ (0.46)**	$ 2.16	$ (2.59)
Basic earnings (loss) from discontinued operations per share, Cdn$ (1)	**0.16**	(0.24)	(0.01)	**0.12**	(0.23)	(0.02)
Basic earnings (loss) per share, Cdn$ (1)	**$ (0.52)**	$ 1.57	$ (1.19)	**$ (0.34)**	$ 1.93	$ (2.61)
Diluted earnings (loss) from continuing operations per share, US$	**$ (0.64)**	$ 1.38	$ (1.20)	**$ (0.40)**	$ 1.87	$ (2.41)
Diluted earnings (loss) from discontinued operations per share, US$	**0.15**	(0.18)	(0.01)	**0.10**	(0.20)	(0.02)
Diluted earnings (loss) per share, US$	**$ (0.49)**	$ 1.20	$ (1.21)	**$ (0.30)**	$ 1.67	$ (2.43)
Diluted earnings (loss) from continuing operations per share, Cdn$ (1)	**$ (0.68)**	$ 1.68	$ (1.18)	**$ (0.46)**	$ 2.00	$ (2.59)
Diluted earnings (loss) from discontinued operations per share, Cdn$ (1)	**0.16**	(0.23)	(0.01)	**0.12**	(0.21)	(0.02)
Diluted earnings (loss) per share, Cdn$ (1)	**$ (0.52)**	$ 1.45	$ (1.19)	**$ (0.34)**	$ 1.79	$ (2.61)
Total assets at December 31	**1,037,552**	1,151,590	1,081,847	**1,037,552**	1,151,590	1,081,847
Total long-term liabilities at December 31	**480,398**	826,011	881,403	**480,398**	826,011	881,403
Cash flows from continuing operating activities	**17,436**	34,199	43,305	**62,019**	97,378	83,327
Cash distributions declared per share, Cdn$	**$ 0.27**	$ 0.27	$ 0.27	**$ 1.09**	$ 1.06	$ 1.06

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

RESULTS OF OPERATIONS

(in thousands of U.S. dollars)	Three months ended December 31		Twelve months ended December 31	
(unaudited)	2009	2008	2009	2008
Project revenue				
Auburndale	$ 18,763	$ 10,003	$ 74,875	$ 10,003
Chambers	12,442	16,714	50,745	68,893
Lake	15,224	15,724	62,285	61,610
Orlando	11,004	13,413	41,911	34,372
Pasco	2,577	13,139	11,356	58,897
Path 15	7,792	7,177	31,000	31,528
Other project assets	4,308	5,807	16,109	36,269
	72,110	81,977	288,281	301,572
Project expenses				
Auburndale	16,745	7,669	59,434	7,669
Chambers	9,878	12,340	43,961	47,683
Lake	12,864	10,502	47,005	39,951
Orlando	9,647	9,670	38,694	31,819
Pasco	3,140	9,657	11,043	48,098
Path 15	3,099	2,643	11,819	10,572
Other project assets	3,549	3,771	12,616	19,225
	58,922	56,252	224,572	205,017
Project other income (expense)				
Auburndale	(2,807)	(225)	(4,950)	(225)
Chambers	(50,805)	75,587	(13,075)	60,455
Lake	(5,797)	9	(5,060)	33
Orlando	(33)	15	(64)	367
Pasco	(42)	(671)	25	(4,356)
Path 15	(3,247)	(3,446)	(11,683)	(13,232)
Other project assets	1,459	4,713	2,570	14,385
	(61,272)	75,982	(32,237)	57,427
Total project income (expense)				
Auburndale	(789)	2,109	10,491	2,109
Chambers	(48,241)	79,961	(6,291)	81,665
Lake	(3,437)	5,231	10,220	21,692
Orlando	1,324	3,758	3,153	2,920
Pasco	(605)	2,811	338	6,443
Path 15	1,446	1,088	7,498	7,724
Other project assets	2,218	6,749	6,063	31,429
Total project (loss) income	(48,084)	101,707	31,472	153,982
Administrative and other expenses (income)				
Management fees and administration	17,637	2,490	26,028	10,012
Interest, net	24,267	9,589	55,665	43,275
Foreign exchange loss (gain)	(1,528)	(27,391)	20,506	(44,692)
Change in fair value of Subordinated Note prepayment option	5,430	–	106	(27)
Other (income) expense, net	327	(42)	255	451
	46,133	(15,354)	102,560	9,019
(Loss) income from continuing operations before income taxes	(94,217)	117,061	(71,088)	144,963
Income tax expense (benefit)	(55,486)	26,084	(46,551)	21,224
(Loss) income from continuing operations	(38,731)	90,977	(24,537)	123,739
Income (loss) from discontinued operations, net of tax	9,163	(12,056)	6,264	(13,051)
Net (loss) income	$ (29,568)	$ 78,921	$ (18,273)	$ 110,688

Overview

The Company has seven reportable segments: Auburndale, Chambers, Lake, Orlando, Pasco, Path 15 and Other Project Assets. Each Project is a separate operating segment. However, several of the Projects are not material from an accounting perspective, individually or in aggregate, and are therefore combined into a single reportable segment, Other Project Assets. The results of operations are discussed below by reportable segment.

Project income is the primary GAAP measure of the Company's operating results and is discussed in "Project Income – Three and twelve months ended December 31, 2009" below. In addition, an analysis of non-project expenses impacting the results of the Company 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 "Financial Instruments" in this MD&A for additional information); (2) the non-cash impact of foreign exchange fluctuations from period to period on the U.S. dollar equivalent of the Company's Canadian dollar-denominated obligations and currency forward contracts; and (3) the related future income tax expense (benefit) associated with these non-cash items.

The Company has previously disclosed expected decreases in cash flows in 2009 compared to prior years. These decreases have historically been included in management's long-term cash flow projections when management periodically confirms the Company's ability to continue paying distributions to shareholders at current levels. See additional details in "Outlook" beginning on page 18 of this MD&A.

Cash flow available for distribution was $15,189 and $67,390 for the three and twelve months ended December 31, 2009, compared to $30,018 and $96,558 for the respective comparable periods in 2008. See "Cash Flow Available for Distribution" in this MD&A for additional information.

Loss from continuing operations before income taxes for the three and twelve months ended December 31, 2009 was $94,217 and $71,088, respectively, compared to income from continuing operations before income taxes of $117,061 and $144,963 for the respective comparable periods in 2008. The change includes significant non-cash and unusual items at the Projects and the corporate level, which are summarized in the following table:

(in thousands of U.S. dollars) (unaudited)	Three months ended December 31 2009	Three months ended December 31 2008	Twelve months ended December 31 2009	Twelve months ended December 31 2008
Project (loss) income, as reported	$ (48,084)	$ 101,707	$ 31,472	$ 153,982
Non-cash items:				
Asset impairment	–	–	(5,500)	–
Change in fair value of derivative instruments	(56,641)	78,028	(11,354)	55,348
Project income, excluding non-cash items noted above	$ 8,557	$ 23,679	$ 48,326	$ 98,634
(Loss) income from continuing operations before income taxes, as reported	$ (94,217)	$ 117,061	$ (71,088)	$ 144,963
Non-cash and unusual items:				
Non-cash items impacting project income noted above	(56,641)	78,028	(16,854)	55,348
Change in fair value of Subordinated Note prepayment option	5,430	–	106	(27)
Management agreement termination	14,100	–	14,100	–
Write-off of Subordinated Notes deferred finance costs	16,244	–	16,244	–
Unrealized foreign exchange loss (gain)	504	(27,674)	24,370	(36,648)
(Loss) income from continuing operations before income taxes, excluding non-cash and unusual items	$ (1,298)	$ 11,359	$ 586	$ 52,940

Project Income – Three and twelve months ended December 31, 2009

AUBURNDALE SEGMENT

The increase in project income of $8,382 for the twelve months ended December 31, 2009 is attributable to the first full year of ownership of the project, which was acquired in November 2008. The decrease in project income of $2,898 for the three months ended December 31, 2009 compared to the same period in the prior year is due to costs associated with the Project's annual maintenance outage that occurs in the fourth quarter of each year. In 2008 the outage occurred shortly before the Company's acquisition of the Project and therefore was not included in 2008 Project income.

CHAMBERS SEGMENT

Project income decreased by $128,202 and $87,956 during the three and twelve months ended December 31, 2009, respectively, compared to the same periods in 2008. The most significant factor in the change for both periods is the non-cash impact of the change in fair value of derivative instruments of $129,533 and $76,656 for the three and twelve months ended December 31, 2009, as compared to the same periods in 2008, which is primarily related to the accounting treatment of the PPA at the Chambers Project as a derivative instrument. The accounting treatment for the PPA does not reflect a change in the amount of cash flow that the Chambers Project will receive under the terms of the PPA. See "Financial Instruments" in this MD&A for additional details about Chambers PPA. In addition, revenue was lower at Chambers as a result of a planned major maintenance outage in the second quarter of 2009 and lower electricity sales volumes and prices throughout 2009.

LAKE SEGMENT

Project income decreased by $8,668 and $11,472 during the three and twelve months ended December 31, 2009, respectively, compared to the same periods in 2008. The decreases are 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 the 2009 periods. These swaps were executed to financially hedge the Project's exposure to the changes in market prices of natural gas. See "Financial Instruments" in this MD&A for additional details about the Company's derivative and other financial instruments.

ORLANDO SEGMENT

Project income at Orlando for the three-month period ended December 31, 2009 was lower than the comparable prior year period due to an insurance settlement of $2,625 recorded in the fourth quarter of 2008 related to the Project's forced outage in the first half of 2008. For the full year 2009, project income was consistent with the prior year as various impacts of the outage in 2008 largely offset one another. Revenue was higher in 2009 while fuel expenses and maintenance costs were lower, all attributable to the 2008 outage.

PASCO SEGMENT

The decrease in Project income at Pasco was attributable to lower revenues from the Project's new ten-year tolling agreement effective January 1, 2009 at lower rates than the power purchase agreement that expired on December 31, 2008, partially offset by lower fuel expense, since the new tolling agreement requires the utility to provide the natural gas needed to generate electricity at the plant.

PATH 15 SEGMENT

Project income at Path 15 for the three and twelve month periods ended December 31, 2009 did not change significantly from comparative periods in 2008.

OTHER PROJECT ASSETS SEGMENT

Project income decreased by $4,531 and $25,366 during the three and twelve months ended December 31, 2009, respectively, compared to the same periods in 2008. The changes are attributable to the following factors:

- The absence of revenue at Onondaga as the contracts that provided substantially all of the Project's cash flow expired in the second quarter of 2008.
- A long-lived asset impairment charge in the third quarter of 2009 at Rumford.
- Lower distributions from the Selkirk Project in 2009 as a result of the expiration of one of the Project's PPAs in mid-2008. In addition, the Project provided no distributions in the fourth quarter of 2009. Current and future projected performance at the Project is expected to prevent cash from being distributed until 2011 under the terms of the Project's non-recourse debt agreement.
- A significant non-recurring distribution received from the Gregory Project during the first quarter of 2008 related to the release of a portion of its debt service reserves.

Administrative and Other Expenses (Income)

Management fees and administration includes the costs of operating as a public company, as well as the fees and costs associated with the Manager. 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. The Company also reimbursed the Manager for reasonable costs incurred to manage the Company. Management fees and administration increased $15,147 and $16,016 for the three and twelve months ended December 31, 2009, respectively, as compared to the respective comparable periods in 2008. The increase is primarily attributable to a $14,100 charge associated with the termination of the management agreements at the end of 2009. See "Overview" in this MD&A for additional details about the termination of the management agreement. 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 the Company's 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. The increase in interest expense for the three and twelve months ended December 31, 2009 compared to the same periods in the prior year is primarily due to the write-off of unamortized Subordinated Note deferred finance costs, the 5% premium on the Subordinated Note call option and the costs associated with the Common Share Conversion of $16,244. In addition, there were amounts outstanding on the Company's revolving credit facility for a portion of the twelve months 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 the Company's Canadian dollar-denominated obligations to holders of Subordinated Notes and Debentures. In addition, unrealized and realized gains and losses on the Company's forward contracts for the purchase of Canadian dollars to satisfy these obligations are included in foreign exchange loss (gain). The U.S. dollar to Canadian dollar exchange rate decreased by 1.9% and 15.9% during the three and twelve months ended December 31, 2009, respectively. During the three and twelve months ended December 31, 2008, the rate increased by 12.6% and 18.6%, respectively. See "Financial Instruments" in this MD&A for additional details about the Company's management of foreign currency risk and the components of the foreign exchange loss (gain) recognized during the three and twelve months ended December 31, 2009 compared to the foreign exchange loss (gain) in the prior periods.

Supplementary Financial Information

The key measure used by management to evaluate the results of the Company's Projects is Cash Flow Available for Distribution. See "Cash Flow Available for Distribution" in this MD&A for additional details and for a reconciliation of Cash Flow Available for Distribution to its nearest GAAP measure, cash flows from operating activities of continuing operations.

The primary factor influencing Cash Flow Available for Distribution is cash distributions received from the Projects. These distributions received are generally funded from 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. Please read "Non-GAAP Financial Measures" in this MD&A for important disclosures with respect to Cash Flow Available for Distribution and Adjusted EBITDA.

Because Project Adjusted EBITDA and Project distributions are key drivers of both the performance of the Company's Projects and Cash Flow Available for Distribution, this MD&A contains supplementary unaudited non-GAAP information that summarizes Adjusted EBITDA by Project and a reconciliation of Adjusted EBITDA by Project to Project distributions actually received by the Company.

Many of the Company's investments are either proportionately consolidated or accounted for under the cost or equity method of accounting in the consolidated financial statements presented in accordance with GAAP. The proportionate consolidation method of accounting is applied by recording in the Company's consolidated financial statements its proportionate share of each financial statement account of the proportionately consolidated Project.

As a result, some components of the Company's balance sheet contain assets that are not directly available to the Company in the normal course of business, or liabilities that are not direct obligations of the Company.

For example, the Company's proportionate share of cash at a proportionately consolidated Project is reflected in the consolidated balance sheet even though this cash may not be directly controlled by the Company because it is subject to: (1) the provisions of the partnership agreement that governs the underlying investment; or (2) in the case of Restricted Cash, the non-recourse debt covenants at the Project. Conversely, the Company's proportionate share of debt at a proportionately consolidated Project is also reflected in the consolidated balance sheet notwithstanding that all of the Project-level debt is secured only by assets at the Project and is non-recourse to the Company.

Project Operations Performance –
Three and twelve months ended December 31, 2009

Aggregate Adjusted EBITDA for the Projects, including earnings from projects accounted for under the equity method, decreased by $13,946, or 33%, during the three months ended December 31, 2009 compared to the same period in 2008 primarily due to the following factors:

- Pasco's new ten-year tolling agreement commenced on January 1, 2009 at lower rates than the power purchase agreement that expired December 31, 2008.
- Lake had higher fuel expense because natural gas was purchased at higher prices than under the supply contract that expired in June 2009. The Company is continuing to execute a hedging strategy to mitigate its future exposure to changes in natural gas prices through 2013 at Lake and Auburndale. See "Financial Instruments – Natural Gas Swaps" in this MD&A for additional information.
- Selkirk is recorded under the cost method of accounting and did not provide any distributions in the fourth quarter of 2009. Current and future projected performance at the Project is expected to prevent cash from being distributed until 2011 under the terms of the Project's non-recourse debt agreement.
- The acquisition of the Auburndale Project in November 2008.
- Orlando received a partial settlement of business interruption and property insurance claims in the fourth quarter of 2008 related to the unplanned outage earlier in 2008.
- Chambers was dispatched less by the utility off-taker in connection with reduced demand and lower power prices in the region. Operating the plant at a lower capacity factor also decreased its efficiency, further contributing to reduced operating margins.

For the twelve months ended December 31, 2009, Project Adjusted EBITDA decreased by $34,761, or 21%, compared to the prior year. In addition to the factors impacting the fourth quarter results described above, the following items are relevant to the year-to-date periods:

- The planned major outage at Chambers in the second quarter of 2009.
- The distribution from the cost method Gregory Project related to the non-recurring release of a portion of debt service reserves at that Project during the first quarter of 2008.
- Onondaga's 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 15.7% lower and 0.4% lower during the three and twelve months ended December 31, 2009, respectively, compared to the same periods in 2008. Weighted average plant availability increased 2.2% and 0.9%, respectively, over the same periods. Generation during the twelve months of 2009 versus the prior year was unfavorably impacted primarily by reduced dispatch at Chambers due to low market prices and a planned major maintenance outage. This was partially 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 95.3% and 95.1% for the three and twelve months ended December 31, 2009, respectively, versus 93.1% and 94.1% in the same respective periods last year. The higher portfolio availability was primarily driven by the increased availability of Orlando compared to the prior period, resulting from the March 2008 unplanned outage, and the acquisition of Auburndale in November 2008, offset slightly by reduced availability at Chambers associated with a longer planned outage than in the prior year. 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 OF CONTINUING OPERATIONS

The Company's 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 expiry 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 from the Projects to the Company during the year can also vary.

The Company's cash flow from operating activities of continuing operations decreased by $16,763 and $35,359 for the three and twelve months ended December 31, 2009, respectively, compared to the same periods in the prior year. The changes from the prior year are partially attributable to the changes in Project Adjusted EBITDA described above. In addition, the $6 million payment in December 2009 under the terms of the management agreement termination reduced operating cash flow for the three and twelve months ended December 31, 2009.

Working capital includes restricted cash and trade receivables at the Company's Projects. 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 operating cash flow in the second and fourth quarters of the year and decreases operating cash flow in the first and third quarters of the year.

CASH FLOW AVAILABLE FOR DISTRIBUTION

Prior to the Common Share Conversion in November 2009, shareholders received monthly cash distributions in the form of interest payments on Subordinated Notes and dividends on common shares. Subsequent to the Common Share Conversion, shareholders receive the same monthly cash distributions of Cdn$1.094 per year in the form of a dividend on the new common shares. Cash flow available for distribution decreased in the three and twelve months ended December 31, 2009 by $14,829 and $29,168, respectively, when compared to the same periods in 2008, due primarily to the changes in cash flow from operating activities of continuing operations described above.

In addition, project-level debt repayments were lower in the 2009 periods because the remaining balance of the non-recourse debt at the Pasco Project was paid in 2008, partially offset by project-level debt payments at Auburndale, which was acquired in November 2008.

The table below presents the Company's calculation of Cash Flow Available for Distribution for the three and twelve months ended December 31, 2009 and 2008.

(in thousands of U.S. dollars, except as otherwise stated)	Three months ended December 31		Twelve months ended December 31	
(unaudited)	2009	2008	2009	2008
Cash Flow Available for Distribution:				
Cash flows from operating activities of continuing operations	**17,436**	34,199	**62,019**	97,378
Project-level debt repayments	**(7,261)**	(12,632)	**(21,633)**	(35,631)
Interest on IPS portion of Subordinated Notes [(1)]	**5,682**	7,923	**30,639**	36,560
Purchase of property, plant and equipment	**(668)**	528	**(3,635)**	(1,749)
Cash Flow Available for Distribution [(2)]	**15,189**	30,018	**67,390**	96,558
Per basic common share	**$ 0.25**	$ 0.49	**$ 1.11**	$ 1.58
Per diluted common share	**$ 0.25**	$ 0.48	**$ 1.07**	$ 1.51
Distributions to Shareholders:				
Interest on IPS portion of Subordinated Notes [(1)]	**5,682**	7,923	**30,639**	36,560
Dividends on common shares	**9,878**	5,463	**27,988**	24,692
Total common share distributions	**15,560**	13,386	**58,627**	61,252
Per common share	**$ 0.26**	$ 0.22	**$ 0.97**	$ 0.99
Payout ratio	**102%**	45%	**87%**	63%
Expressed in Cdn$				
Cash flow available for distribution, Cdn$	**16,057**	36,387	**76,884**	103,081
Per basic common share, Cdn$	**$ 0.27**	$ 0.59	**$ 1.27**	$ 1.68
Per diluted common share, Cdn$	**$ 0.27**	$ 0.57	**$ 1.22**	$ 1.61
Total common share distributions, Cdn$	**16,534**	16,328	**66,325**	65,143
Per common share, Cdn$	**$ 0.27**	$ 0.27	**$ 1.09**	$ 1.06

(1) Prior to the Common Share Conversion on November 27, 2009, a portion of the Company's 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 Common Share Conversion, the entire monthly cash distribution is paid in the form of a dividend on the Company's common shares.

(2) Cash Flow 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 issuers. See "Non-GAAP Financial Measures."

DISCUSSION OF DISTRIBUTABLE CASH

(in thousands of U.S. dollars) (unaudited)	Three months ended December 31 2009	Years ended December 31 2009	2008	2007
Cash flows from operating activities of continuing operations (A)	$ 17,436	$ 62,019	$ 97,378	$ 83,327
Net income (loss) (B)	(29,568)	(18,273)	110,688	(149,205)
Actual cash distributions paid:				
Interest on subordinated notes	5,682	30,639	36,560	36,235
Dividends (C)	9,878	27,988	24,692	24,665
Excess of cash flows from operating activities of continuing operations over dividends paid (A – C)	7,558	34,031	72,686	58,662
Excess (shortfall) of net income over dividends paid (B – C)	(39,446)	(46,261)	85,996	(173,870)

As illustrated in the table above, the Company has historically generated substantially more in cash flows from operating activities of continuing operations than it has paid in dividends. The interest and dividend payments in the table above are expressed in U.S. dollars but are paid in Canadian dollars. The payments in the table do not reflect the impact of the Company's contracts for forward purchases of Canadian dollars.

See "Financial Instruments" in this MD&A for additional details about the Company's forward currency contracts.

The Company periodically evaluates its level of cash dividends with its Board of Directors by analyzing long-term cash flow projections, as well as the accretion to cash flow provided by acquisitions. In addition, the Company maintains cash on hand to be deployed for acquisitions and other growth opportunities at existing projects.

Management believes that its calculation of Cash Flow Available for Distribution on the previous page provides meaningful information about the Company's ability to pay dividends from cash generated by the operations of its operating assets.

SUMMARY OF QUARTERLY RESULTS

Variations in quarterly results are driven by the following factors:

- Seasonality of Project revenues created by seasonal variances in demand for electric power, in some cases varied seasonal pricing for portions of the PPA payments and the typical scheduling of major facility maintenance in the spring and fall.
- Variations in cash flow may also be driven by the timing of quarterly and semi-annual Project-level debt payments, as distributions from the Projects to the Company must occur in conjunction with passing certain tests at those payment dates.
- Non-cash charges, principally: (1) the change in fair value of certain financial instruments that are required by GAAP to be revalued at each balance sheet date (see "Financial Instruments" in this MD&A for additional information); and (2) the non-cash portion of the foreign exchange gain or loss, reflecting the impact of foreign exchange fluctuations from period to period on the U.S. dollar equivalent of the Company's Canadian dollar-denominated debt and the mark-to-market value of currency forward contracts.

The table below presents selected quarterly consolidated financial data for the eight most recently completed fiscal quarters (in thousands of U.S. dollars, except as otherwise stated):

(in thousands of U.S. dollars, except as otherwise stated) (unaudited)	2008				2009			
	Q1	Q2	Q3	Q4	Q1	Q2	Q3	Q4
Project revenues	72,117	73,091	74,387	81,977	77,251	68,402	70,518	**72,110**
Net income (loss)	5,665	(40,054)	66,166	78,921	(32,205)	19,604	23,895	**(29,568)**
Cash flows from operating activities of continuing operations	25,815	30,541	6,823	34,199	13,504	22,941	8,138	**17,436**
Cash distributions	16,221	16,197	15,448	13,386	13,306	14,444	15,317	**15,560**
Cash available for distribution	28,514	27,890	10,150	30,004	16,847	22,900	12,454	**15,189**
Payout ratio	57%	58%	152%	45%	79%	63%	123%	**102%**
Per common share statistics								
Net income (loss) – basic	0.09	(0.65)	1.08	1.30	(0.53)	0.32	0.39	**(0.49)**
Net income (loss) – diluted	0.09	(0.65)	1.00	1.20	(0.53)	0.30	0.36	**(0.49)**
Cash flows from operating activities of continuing operations	0.42	0.50	0.11	0.56	0.22	0.38	0.13	**0.29**
Cash available for distribution, US$	0.46	0.45	0.17	0.49	0.28	0.38	0.21	**0.25**
Cash available for distribution, Cdn$	0.47	0.46	0.17	0.59	0.34	0.44	0.23	**0.27**
Distributions, US$	0.26	0.26	0.25	0.22	0.22	0.24	0.25	**0.26**
Distributions, Cdn$	0.27	0.27	0.26	0.27	0.27	0.27	0.27	**0.27**

OUTLOOK

Based on management projections, the Company's cash on hand and projected cash flows from existing projects are sufficient to meet the current level of dividends to common shareholders into 2015 before considering any positive impact from potential acquisitions or organic growth opportunities.

Based on year-to-date results and management projections for the remainder of the year, the Company expects to receive distributions from its Projects in the range of $70 million to $77 million for the full year 2010, resulting in a payout ratio estimated to be near 100%. This amount represents a decrease of approximately $23 million to $30 million compared to distributions received from the Projects in 2009. Additional details about these changes are included below.

At the corporate level, management expects net cash taxes for 2010 to be a refund in the range of $7 million to $9 million, compared to insignificant net cash taxes in 2009. Also included in 2010 corporate-level cost will be the $5 million payment under the terms of the management agreement termination, compared to the $6 million payment in 2009.

The reductions in Project distributions expected in 2010 have historically been included in management's long-term cash flow projections when management periodically confirms the Company's ability to continue paying dividends to shareholders at current levels.

Looking ahead to 2011, management expects overall levels of cash flow and the payout ratio to be generally consistent with 2010. Higher Project distributions and a slightly lower payment under the management agreement termination are expected to be offset by the non-recurrence of the cash tax refunds that are anticipated in 2010. In 2012, still higher distributions from Projects are expected to increase operating cash flow and reduce the payout ratio significantly compared to 2010 and 2011. The most significant factor in the expected higher operating cash flow in 2012 is increased distributions from Selkirk following the final payment of its non-recourse project-level debt in 2012.

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

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

In 2009, the following five Projects comprised approximately 86% of Project distributions received: Auburndale, Lake, Orlando, Path 15 and Pasco. For 2010, management expects these same five projects to contribute a similar proportion of total Project distributions.

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

Lake

The Lake Project is exposed to changes in natural gas prices after the expiration of its natural gas supply contract on June 30, 2009 through to the expiry of its PPA in July 2013. The Company continues to execute a hedging strategy to mitigate this exposure by periodically entering into financial swaps that effectively fix the forward price of natural gas required at the Project. Management has taken advantage of the low market price of natural gas to make significant progress in its natural gas hedging strategy. These hedges are summarized in "Financial Instruments – Natural Gas Swaps" in this MD&A. Management intends to continue, when appropriate, to evaluate opportunities to further mitigate natural gas price exposure at Lake in the 2010 to 2013 period.

The variable energy revenues in the Lake Project's PPA are indexed to the price of coal consumed by a specific utility plant in Florida. The components of this coal price are proprietary to the utility, but management believes the utility purchases coal for that plant under a combination of short to medium-term contracts and spot market transactions.

The Company expects to receive distributions from the Lake Project of approximately $25 million to $27 million in 2010. In 2011 and 2012, distributions from Lake are expected to be $28 million to $32 million per year. The increases expected in 2011 and 2012 are primarily due to higher contractual capacity revenue and lower natural gas prices than in 2010, as a result of the Company's hedging activities.

The estimates above are based on management's current internal models as of March 29, 2010. The Company's models are based on future natural gas prices forecasted by Cambridge Energy Research Associates, an independent third-party energy consulting firm. The 2010 natural gas price exposure at Lake has been substantially hedged. In 2010, projected cash distributions at Lake would change by only $0.7 million per $1.00/MMBtu change in the price of natural gas based on the current level of unhedged natural gas volumes at the Project.

Coal prices used in the electricity revenue component of the projected distributions from the Lake Project incorporate a forecast of the applicable Crystal River facility coal costs provided by the utility based on its 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.

Auburndale

Based on the current forecast, the Company expects distributions from Auburndale of $24 million to $26 million per year from 2010 through 2013, when the Project's current PPA expires. Distributions received from Auburndale in the 2010 through 2013 period will be impacted by projected coal and gas prices in the forecast period.

The projected revenue from the Auburndale PPA contains a component related to coal costs at the utility off-taker's Crystal River facility as described above for the Lake Project. Because that mechanism does not pass through changes in the Project's fuel costs, Auburndale's operating margin is exposed to changes in natural gas prices for approximately 20% of its natural gas requirements through to the PPA's expiration in mid-2012. The remaining 80% of the Project's fuel requirements are supplied under an agreement with fixed prices through its expiration in mid-2012. The Company has been executing a strategy to mitigate the future exposure to changes in natural gas prices at Auburndale by periodically entering into financial swaps that effectively fix the forward price of natural gas required at the Project. See "Financial Instruments – Natural Gas Swaps" in this MD&A for additional details about hedge contracts executed as of March 29, 2010. The 2010 natural gas price exposure at Auburndale has been substantially hedged. In 2010, projected cash distributions at Auburndale would change by only $0.5 million per $1.00/MMBtu change in the price of natural gas based on the current level of unhedged natural gas volumes at the Project. Management intends to continue, when appropriate, to evaluate opportunities to further mitigate natural gas price exposure at Auburndale in the 2011 to 2013 period.

Chambers

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

As previously reported, the reduced cash flows resulted in the Project not meeting cash flow coverage ratio tests in its non-recourse debt facility, so there were no distributions to the Company in 2009. Based on management's current projections, the Company will resume receiving distributions from the Project in the second half of 2010 because it will meet the required debt service coverage ratios.

LIQUIDITY AND CAPITAL RESOURCES

Overview

The Company's primary source of liquidity is distributions from the Projects and its revolving credit facility. A significant portion of the cash received from Project distributions is distributed in the form of interest and dividends to holders of the common shares, the Debentures and, prior to the Common Share Conversion, the Subordinated Notes. The Company 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.

Management believes that the Company will be able to generate sufficient amounts of cash and cash equivalents to maintain the Company's operations and meet obligations as they become due. The Company's cash on hand and projected future cash flows are adequate to meet the current level of cash dividends to common shareholders into 2015 before considering any positive impact from potential acquisitions or organic growth opportunities.

Management does not expect any material unusual requirements for cash outflows in 2010 for capital expenditures or other required investments. In addition, there are no debt instruments with significant maturities or refinancing requirements in 2010. See "Outlook" in this MD&A for information about changes in expected distributions from the Company's Projects in 2010.

Common Share Conversion

On November 24, 2009, the shareholders approved the Common Share Conversion. Subsequent to the Common Share Conversion, the Company continued to maintain its business strategy and its current distribution levels. Each IPS has been exchanged for one new common share of the Company. The Company's entire current monthly cash distribution of Cdn$0.0912 per common share is being paid as a dividend on the new common shares.

The Company believes that a traditional common share structure provides significant benefits to the Company and its stakeholders. These benefits include the following:

- Effectively increased after-tax cash distributions to taxable investors in Canada and the U.S. by approximately 19% and 16%, respectively.
- Reduced the complexity associated with the Company's prior IPS capital structure, which is expected to result in reduced costs and enhance the Company's ability to raise new capital or undertake transactions in furtherance of its business strategy.
- Broadens the base of potential investors in the Company to those investing in traditional common share structures, which the Board of Directors expects will enhance the Company's access to, and cost of, capital.
- Enables a planned application to list the new common shares on the NYSE during the first half of 2010. The Company has been pre-approved by the NYSE to apply for listing. The associated registration with the U.S. Securities and Exchange Commission will allow the Company to actively pursue potential U.S. institutional and retail investors.
- Reduces the Company's financial leverage and eliminates the refinancing risk associated with the scheduled maturity in 2016 of the Subordinated Notes that formed part of the IPSs.

Credit Facility

The Company maintains 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.

In November 2008, the Company borrowed $55,000 under the credit facility and used the proceeds to partially fund the acquisition of Auburndale. The Company had executed an interest rate swap to fix the interest rate at 2.4% through November 2011 for the balance outstanding under this borrowing. During 2009, $55,000 of the outstanding borrowing under the credit facility was repaid with cash on hand, so the interest rate swap associated with this facility was terminated.

Outstanding amounts under the credit facility bear interest at the London Interbank Offered Rate ("LIBOR") plus an applicable margin between 1.50% and 3.25% that varies based on the credit ratio of a subsidiary of the Company. As of December 31, 2009, the applicable margin was 1.50%. The Company amended the credit facility in order to facilitate the Common Share Conversion. Under the terms of the amendment, the Company paid a fee of $250 and changed the method of computing the applicable margin on amounts outstanding under the credit facility from cash flow ratios to cash flow and indebtedness ratios.

As of December 31, 2009, $43,855 was allocated, but not drawn, to support letters of credit for contractual credit support at seven of the Company's Projects.

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

Convertible Debentures

On October 11, 2006, the Company issued, in a public offering, Cdn$60,000 aggregate principal amount of 6.25% convertible secured 2006 Debentures for gross proceeds of $52,780. 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 the Company's interest in certain subsidiaries and contain certain restrictive covenants.

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.

On December 17, 2009, the Company issued, in a public offering, Cdn$75,000 aggregate principal amount of 6.25% convertible 2009 Debentures for gross proceeds of $71,361. 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.

On December 24, 2009, the underwriters exercised their over-allotment option in full to purchase an additional Cdn$11,250 aggregate principal amount of the 2009 Debentures.

A portion of the proceeds from the 2009 Debentures was used to redeem the remaining Cdn$40,677 principal value of Subordinated Notes at 105% of the principal amount. See "Financial Instruments" in this MD&A for additional details.

Project-Level Debt

The following table summarizes the maturities of Project-level debt. The amounts represent the Company's proportionate share of the non-recourse Project-level debt balances at December 31, 2009 and exclude any purchase accounting adjustments recorded to adjust the debt to its fair value at the time the Project was acquired by the Company. 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, 2009, the covenants at the

Chambers, Selkirk and Delta-Person Projects are temporarily preventing those Projects from making cash distributions to the Company. Management expects the Selkirk Project to resume cash distributions in 2011. See "Outlook" in this MD&A for guidance related to the Chambers Project. All Project-level debt is non-recourse to the Company and substantially all of the principal is amortized over the life of the Projects' PPAs.

The range of interest rates presented represents the rates in effect at December 31, 2009.

(in thousands of U.S. dollars, except as otherwise stated)	Range of interest rates	Total remaining principal repayments	2010	2011	2012	2013	2014	Thereafter
Consolidated and proportionately consolidated Projects								
Chambers	0.4%-8.4%	$ 123,578	$ 12,051	$ 12,794	$ 13,676	$ 13,783	$ 10,780	$ 60,494
Path 15	7.9%-9.0%	161,348	7,480	7,987	8,667	9,402	8,065	119,747
Auburndale	5.1%	31,500	9,800	9,800	7,000	4,900	–	–
Total consolidated and proportionately consolidated Projects		316,426	29,331	30,581	29,343	28,085	18,845	180,241
Equity and cost method Projects								
Delta-Person	2.1%	12,082	1,147	1,220	1,308	1,403	1,505	5,499
Selkirk	9.0%	23,875	8,247	10,188	5,440	–	–	–
Gregory	1.8%-7.5%	16,040	1,757	1,901	2,044	2,205	2,385	5,748
Total equity and cost method Projects		51,997	11,151	13,309	8,792	3,608	3,890	11,247
Total all Projects		$ 368,423	$ 40,482	$ 43,890	$ 38,135	$ 31,693	$ 22,735	$ 191,488

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 or proportionately consolidated with Atlantic Power, these amounts, or Atlantic Power's portion of these amounts, are reflected as Restricted Cash on the Company's consolidated balance sheet. At December 31, 2009, Restricted Cash at consolidated and proportionately consolidated Projects totaled $17,381.

Contractual Obligations

Contractual obligations of the Company as at the period ended December 31, 2009 are presented in the table below.

		Payments due by period			
(in thousands of U.S. dollars)	Total	2010	2011-2012	2013-2014	Thereafter
Long-term debt, including current portion (a)	$ 316,425	$ 29,331	$ 59,924	$ 46,930	$ 180,240
Convertible debentures (b)	139,153	–	–	57,088	82,065
Head office lease (c)	1,577	286	593	620	78
Total contractual obligations	$ 457,155	$ 29,617	$ 60,517	$ 104,638	$ 262,383

(a) Long-term debt, including current portion

Long-term debt represents the Company's consolidated and proportionately consolidated share of Project long-term debt. The amount presented excludes the net unamortized purchase price adjustment of $12,030 related to the fair value of debt assumed in the Path 15 acquisition. Project debt is non-recourse to the Company and is generally amortized over the term of the respective revenue generating contracts of the Projects. The range of interest rates on long-term Project debt at December 31, 2009 was 0.04% to 9.0%.

(b) Convertible debentures

The 2006 Debentures pay interest semi-annually on April 30 and October 31 of each year. The 2006 Debentures mature on October 31, 2014 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 2009 Debentures pay interest semi-annually on March 15 and September 15 of each year, commencing 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.

(c) Head office lease

These lease payments are associated with the lease of the Company's headquarters office in Boston, MA which expires on March 31, 2015.

Project Contracts

Each Project typically has a set of contracts that include obligations of the

Project partnerships, all of which are non-recourse to the Company. Therefore, specific contracts for individual Projects are not discussed in detail in the MD&A or included in the Contractual Obligations table above. The following are general characteristics of the typical contracts at the Projects:

- PPAs typically provide for capacity payments based on plant availability and energy payments based on actual generation. They generally allow Projects to pass through their fuel costs. See the table in the "Project Portfolio" section in this MD&A with respect to off-takers and durations.
- Fuel supply agreements are typically requirements-based, with no minimum purchase obligations.
- Fuel transportation agreements may incorporate capacity reservation/demand payments for natural gas or shipping cost per ton of coal.
- Steam sales agreements typically have a tenor that matches that of the related PPA and are designed to meet regulatory requirements for thermal load/ efficiency at fossil fuel plants.
- Operating and maintenance agreements specify services provided by third parties or owners.
- Long-term service agreements may be in place for gas or steam turbine inspections and overhauls.
- Site lease agreements grant use of project land where Projects do not own the site.

Further information about the Projects' agreements is contained in the Company's annual information form dated March 29, 2010, which is available on SEDAR's website at www.sedar.com.

INFORMATION REGARDING GUARANTORS

The 2006 Debentures are secured by a pledge of the Company's membership interests in Atlantic Power Holdings and are guaranteed by Atlantic Power Holdings and Teton Power Funding, LLC, Epsilon Power Funding, LLC, MP Power LLC, Teton East Coast Generation LLC, Teton Selkirk LLC, Badger Power Generation I LLC, Badger Power Generation II LLC, Baker Lake Hydro LLC, Dade Investment, L.P., MEP Rumford, LLC, NCP Dade Power LLC, NCP Pasco LLC, Olympia Hydro LLC, Orlando Power Generation I LLC, Orlando Power Generation II LLC, Stockton Cogen (II) LLC, Teton Operating Services, LLC and Teton New Lake, LLC (the "Guarantors"). The guarantee of Holdings is secured by a pledge of its membership interests in Teton Power Funding, LLC and Epsilon Power Funding, LLC and the guarantees of certain of the Guarantors are secured by pledges of the membership interests or other securities they hold in subsidiary entities subject to the provisions of agreements governing or affecting interests in such subsidiaries, which may restrict or prevent pledges in certain cases.

The consolidated financial statements of the Company include the consolidated financial results of the Company and its guarantor and non-guarantor subsidiaries. Summary unaudited consolidated financial information of the Company, the Guarantors and the non-guarantor subsidiaries of the Company as at and for the twelve-month period ended December 31, 2009 is presented in the table below. The selected financial information for the Company and for the Guarantors includes certain investments in subsidiaries accounted for on a cost basis and is therefore not presented in accordance with GAAP.

(thousands of U.S. dollars)	Atlantic Power Corporation	Guarantor subsidiaries	Non-guarantor subsidiaries	Consolidation adjustments	Consolidated
Income Statement – Year Ended December 31, 2009					
Project revenue	$ –	$ –	$ 288,281	$ –	$ 288,281
Project expenses	–	(254)	224,826	–	224,572
Project other income (expense)	–	5,617	(37,854)	–	(32,237)
Project income	–	5,871	25,601	–	31,472
Dividends received	62,703	100,160	–	(162,863)	–
Administrative and other expenses	110,520	(7,928)	(32)	–	102,560
Income (loss) from continuing operations before income taxes	(47,817)	113,959	25,633	(162,863)	(71,088)
Income taxes	(46,555)	4	–	–	(46,551)
Income (loss) from continuing operations	(1,262)	113,955	25,633	(162,863)	(24,537)
Income (loss) from discontinued operations	–	(1,620)	7,884	–	6,264
Income (loss)	$ (1,262)	$ 112,335	$ 33,517	$ (162,863)	$ (18,273)
Balance Sheet - December 31, 2009					
Current assets	$ 53,796	$ 11,197	$ 87,483	$ (3,136)	$ 149,340
Investments in guarantor subsidiaries	504,470	–	–	(504,470)	–
Investment in non-guarantor subsidiaries	–	538,586	–	(538,586)	–
Other non-current assets	14,289	23	812,863	61,037	888,212
Total non-current assets	518,759	538,609	812,863	(982,019)	888,212
Total assets	572,555	549,806	900,346	(985,155)	1,037,552
Current liabilities	10,312	12,944	57,351	(3,136)	77,471
Non-current liabilities	143,596	32,392	304,410	–	480,398
Shareholders' equity	418,647	504,470	538,585	(982,019)	479,683
Total liabilities and shareholders' equity	$ 572,555	$ 549,806	$ 900,346	$ (985,155)	$ 1,037,552

FINANCIAL INSTRUMENTS

The following table contains the components of income (expense) related to changes in the fair value of the Company's derivative financial instruments:

(unaudited)	Three months ended December 31 2009	2008	Twelve months ended December 31 2009	2008
Change in fair value of derivative instruments:				
Chambers power purchase agreement	$ (49,728)	$ 83,220	$ (6,776)	$ 74,608
Onondaga indexed swap and hedge	–	–	–	(10,844)
Project-level interest rate swaps	882	(5,192)	2,604	(5,038)
Project-level natural gas swaps	(7,795)	–	(7,182)	(3,378)
	$ (56,641)	$ 78,028	$ (11,354)	$ 55,348

Chambers Power Purchase Agreement

The PPA at the proportionately consolidated Chambers Project meets the accounting definition of a derivative instrument. The PPA does not qualify for exclusion from Canadian Institute of Chartered Accountants ("CICA") Handbook Section 3855, Financial Instruments – Recognition and Measurement, and has not been designated as a hedge. Accordingly, the PPA has been recorded at its fair value in the consolidated balance sheets and changes in the fair value are recognized in change in fair value of derivative instruments in the consolidated statements of income (loss), comprehensive income (loss), and deficit.

The fair value of the PPA is measured by comparing the net present value of the cash flows expected to be received under the terms of the PPA to the net present value of the cash flows that would be received if the same volumes were sold at projected market power prices over the term of the contract expiring in 2024. Accordingly, periodic changes to the fair value of the PPA reflect changes in forward market conditions and do not reflect a change in the amount of cash flow the Chambers Project will receive under the terms of the PPA. The most significant factor that impacts the calculated fair value of the PPA is the projected forward market prices of power, and such prices can vary significantly from period to period. As of December 31, 2009, a 10% change in the projected average forward power prices through the term of the PPA expiring in 2024 would change the fair value of the PPA by approximately $33 million.

Foreign Currency Forward Contracts

The Company uses forward foreign currency contracts to manage its exposure to changes in foreign exchange rates, as the Company earns its income in the United States but pays dividends to shareholders and interest on convertible debentures predominantly in Canadian dollars. Since its inception, the Company has established a hedging strategy for the purpose of reinforcing the long-term sustainability of cash distributions to holders of IPSs and common shares. The Company has executed this strategy by entering into forward contracts to purchase Canadian dollars at a fixed rate of Cdn$1.134 per U.S. dollar in amounts sufficient to make monthly distributions through December 2013 at the current annual dividend level of Cdn$1.094 per common share, as well as interest payments on the 2006 Debentures. It is the Company's intention to periodically consider extending the length of these forward contracts.

In addition, the Company has executed forward contracts to purchase Canadian dollars at fixed rates of exchange sufficient to make semi-annual interest payments on the 2006 Debentures. The contracts provide for the purchase of Cdn$1.9 million in April and in October of each year through 2011 at a rate of Cdn$1.1075 per U.S. dollar. It is the Company's intention to periodically consider extending the length of these forward contracts.

The foreign exchange forward contracts are recorded at estimated fair value based on quoted market prices and the estimation of the counterparty's credit risk, as required by the Emeging Issues Committee ("EIC") EIC-173, Credit Risk and the Fair Value of Financial Assets and Financial Liabilities. Changes in the fair value of the foreign currency forward contracts are reflected in foreign exchange (gain) loss in the consolidated statements of income (loss), comprehensive income (loss) and deficit.

The following table contains the components of recorded foreign exchange (gain) loss for the periods indicated:

	2009	2008
Unrealized foreign exchange (gain) loss:		
Subordinated Notes and convertible debentures	$ 55,508	$ (85,212)
Forward contracts and other	(31,138)	48,564
	24,370	(36,648)
Realized foreign exchange (gain) on forward contract settlements	(3,864)	(8,044)
	$ 20,506	$ (44,692)

The following table illustrates the (gain) loss that would be recorded on the Company's financial instruments in the event of a 10% hypothetical change in the value of the U.S. dollar compared to the Canadian dollar as of December 31, 2009:

Convertible debentures	$ (13,915)
Foreign currency forward contracts	(30,204)
	$ 44,119

Pasco Natural Gas Swaps

The Pasco Project's operating margin was exposed to changes in natural gas prices for the second half of 2008 as a result of the expiry of its favorably-priced natural gas supply contract on June 30, 2008 before the expiry of its PPA at the end of 2008. In the second quarter of 2008, the Company entered into a series of financial swaps that effectively fixed the price of natural gas at the Pasco Project during the second half of 2008.

These natural gas swaps were derivative financial instruments and the changes in the fair value of the natural gas swaps were recorded in change in fair value of derivative instruments in the consolidated statements of income (loss), comprehensive income (loss) and deficit. The natural gas swaps at Pasco expired in December 2008.

Beginning on January 1, 2009, a new ten-year tolling agreement at the Pasco Project requires the PPA counterparty to provide natural gas needed to operate the plant and, as a result, the Pasco Project is no longer exposed to changes in market prices of natural gas.

Lake and Auburndale Natural Gas Swaps

The Lake Project's operating margin is exposed to changes in the market prices of natural gas from the expiry of its natural gas supply contract on June 30, 2009 through to the expiry 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 market prices and therefore the Project is exposed to changes in natural gas prices for that portion of its natural gas requirements through the termination of the fuel supply agreement and 100% of its natural gas requirements from the expiry of the fuel contract in mid-2012 until the expiry of its PPA.

The Company has executed its 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 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, the Company has de-designated these natural gas swap hedges and the changes in their fair value are recorded in change in fair value of derivative instruments in the consolidated statements of income (loss), comprehensive income (loss) and deficit.

The following table summarizes the hedge position related to natural gas needed to meet PPA requirements at Lake and Auburndale as of December 31, 2009, including additional swaps executed during first quarter 2010:

As of December 31, 2009	2010	2011	2012	2013
Portion of gas volumes currently hedged:				
Lake:				
Contracted	–	–	–	–
Financially hedged	80%	65%	90%	65%
Total	**80%**	**65%**	**90%**	**65%**
Auburndale:				
Contracted	80%	80%	40%	–
Financially hedged	15%	13%	19%	65%
Total	**95%**	**93%**	**59%**	**65%**
Average price of financially hedged volumes (per MMBtu):				
Lake	$7.11	$6.65	$6.90	$7.05
Auburndale	$6.30	$6.68	$6.67	$7.02

As of March 29, 2010	2010	2011	2012	2013
Portion of gas volumes currently hedged:				
Lake:				
Contracted	–	–	–	–
Financially hedged	80%	78%	90%	65%
Total	**80%**	**78%**	**90%**	**65%**
Auburndale:				
Contracted	80%	80%	40%	–
Financially hedged	15%	13%	32%	79%
Total	**95%**	**93%**	**72%**	**79%**
Average price of financially hedged volumes (per MMBtu):				
Lake	$7.11	$6.52	$6.90	$7.05
Auburndale	$6.30	$6.68	$6.51	$6.92

Subordinated Notes Prepayment Option

The Company had the option to redeem the Subordinated Notes beginning on November 18, 2009 at an initial redemption price equal to 105% of the principal amount being redeemed. The Company determined that the redemption option is an embedded derivative that was recorded at fair value and periodic changes in fair value were recorded in other expenses in the consolidated statements of income (loss), comprehensive income (loss) and deficit.

On December 17, 2009, the Company exercised its Subordinated Note Call Option to redeem the remaining Cdn$40,677 principal value of Subordinated Notes at 105% of the principal amount. See "Liquidity and Capital Resources" in this MD&A for additional information. As of December 31, 2009, all Subordinated Notes have either been converted to new common shares or redeemed for cash and therefore the prepayment option no longer exists.

Interest Rate Swaps

The Company's proportionately consolidated Chambers Project has executed interest rate swaps to economically fix a portion of the Project's exposure to changes in interest rates related to variable-rate project debt. These interest rate swaps are derivative financial instruments and are not designated as hedges for accounting purposes. Interest rate swaps are recorded at fair value as derivative financial instruments in the consolidated balance sheet and changes in fair value are recorded in change in fair value of derivative instruments in the consolidated statements of income (loss), comprehensive income (loss) and deficit. The primary factor that influences the fair value of interest rate swaps is changes in projected forward market interest rates.

The fair value of interest rate swaps reflects the cash flows due to or from the Company on the balance sheet date. Cash settlements related to interest rate swaps are recorded in interest expense in the consolidated statements of income (loss), comprehensive income (loss) and deficit.

The Company has executed interest rate swaps on the revolving credit facility and the non-recourse loan at its consolidated Auburndale Project to economically fix a portion of the respective exposure to changes in interest rates related to variable-rate debt. The interest rate swap agreements were designated as a cash flow hedge of the forecasted interest payments under the project-level Auburndale debt and the credit facility when they were executed in November 2008. The interest rate swap termination date for the Auburndale project-level debt was November 30, 2009. On November 30, 2009, the Company terminated the interest rate swap on the revolving credit facility when the remaining outstanding balance on the credit facility was repaid.

In November 2009, the Company executed a new interest rate swap at Auburndale that terminates on November 30, 2013. The interest rate swaps are derivative financial instruments and are recorded in the consolidated balance sheet at fair value. Changes in the fair value of the interest rate swaps are recorded in other comprehensive income (loss) as they have been designated as a hedge of the risks associated with the changes in market interest rates.

Loans and Receivables

Accounts receivable is primarily comprised of amounts due to the Company's consolidated and proportionately consolidated projects for sales of electricity under long-term contracts. As of December 31, 2009, there are no significant amounts of accounts receivable past due. The carrying value of loans and receivables approximates their fair value due to the short-term maturity of those financial instruments.

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 the Company receives from the Projects are made net of capital expenditures needed at the Projects. The Company has injected funds into the Projects for significant elective equipment upgrades to output and efficiency. The Projects in which the Company has 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 2009, several of the Projects undertook planned outages to complete major maintenance work that prolonged the life and ensured efficient and reliable operation of the assets. Major overhaul inspections were conducted during the period at Badger Creek, Chambers and Selkirk. The principal maintenance activity at Chambers was a major overhaul of the Project's steam turbine. Selkirk conducted major overhaul inspections of two of its three gas turbines in 2009. Both Chambers and Selkirk have reserves that are funded from operating cash flow in anticipation of major maintenance expenditures. Reserve withdrawals cover a substantial portion of the actual maintenance costs. Typically, Selkirk is able to fully mitigate lost operating margin through the resale of natural gas not consumed. Costs associated with the major gas turbine overhaul at Badger Creek are paid for by the operator of the plant based on a levelized operation and maintenance fee that the operator is paid by the Project. Minor gas turbine inspections and overhauls were completed at Gregory and Auburndale. Both Gregory and Auburndale have long-term service agreements ("LTSAs") in place for their gas turbines with payments over time that cover a substantial portion of the overhaul cost. Gregory also funds a reserve over time to cover certain maintenance expenditures. Each of the Projects conducts maintenance activities during periods of the year when impacts to the Project's margin on energy sales and contractual availability requirements can be minimized.

In 2010, several of the Projects have planned outages to complete maintenance work. The level of maintenance and capital expenditures is reduced from 2009. Selkirk has planned a major overhaul of a steam turbine and a minor inspection of one of its combustion turbines, with costs and lost margin largely covered by reserves and proceeds from gas resales, respectively. Auburndale will also conduct a minor inspection of one of its combustion turbines covered by its LTSA in conjunction with other maintenance work. Chambers is scheduled to conduct inspections and customary repairs on both its boilers. Typically, Chambers staggers the inspections of its two boilers from year to year; however, the boiler inspection in 2009 was deferred to 2010 in order to preserve a high availability factor given the anticipated reduced availability associated with the Project's steam turbine overhaul in 2009. A minor gas turbine inspection is also scheduled at Orlando.

COMMITMENTS AND CONTINGENCIES

From time to time, the Company and its subsidiaries and Projects are parties to disputes and litigation that arise in the normal course of business. The Company assesses its exposure to these matters and records estimated loss contingencies when a loss is likely and can be reasonably estimated. There were no matters pending as of December 31, 2009 which are expected to have a material impact on the Company's financial position or results of operations.

RELATED PARTY TRANSACTIONS

Prior to December 31, 2009, the Company was managed by the Manager, which was owned by the ArcLight Funds managed by ArcLight Capital Partners, LLC. On December 31, 2009, the Company terminated its management agreements with the Manager and has agreed to pay the ArcLight Funds an aggregate of $15 million, to be satisfied by a payment of $6 million on 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. In connection with the termination of the management agreements, the Company hired all current employees of the Manager and entered into new employment agreements with the officers of the Manager.

Fees paid to the Manager under the management agreement included: (1) a base management fee of $373 in 2009; (2) a reimbursement of costs; and (3) an incentive fee equal to 25% of distributions paid to shareholders during the year in excess of Cdn$1.00 per IPS, which amounted to $1,259 in 2009. The Management Agreement had an initial term of 20 years, expiring in 2024. In addition, the Path 15 Project directly paid the Manager an annual fee of $266, which was subject to adjustment for inflation.

OUTSTANDING SHARE DATA

The Company had 60,404,093 common shares outstanding at March 29, 2010 and December 31, 2009. As of December 31, 2008, 60,937,731 IPSs were outstanding.

During 2008 and 2009, the Company acquired 1,040,220 common shares at an average price of Cdn$8.61 under the terms of its normal course issuer bid. Atlantic Power paid the market price at the time of acquisition for any common shares purchased through the facilities of the TSX, and all common shares acquired under the bid have been canceled. The issuer bid expired on July 24, 2009. The Company does not anticipate additional share repurchases at this time.

The 2006 Debentures are convertible to 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 2009 Debentures are convertible to approximately 76.9231 common shares per Cdn$1,000 principal amount of 2009 Debentures, at any time, at the option of the holder, representing a conversion price of Cdn$13.00 per common share. As of December 31, 2009, approximately 11,473,326 common shares would be required to be issued if all of the outstanding Debentures were converted to common shares.

On March 30, 2009 and March 26, 2008, the Board of Directors approved grants of notional units to acquire a maximum of 267,408 and 142,717 common shares, respectively, under the terms of the Company's Long-Term Incentive Plan.

CRITICAL ACCOUNTING ESTIMATES

The preparation of financial statements requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities and the disclosure of contingent assets and liabilities at the date of the financial statements and the reported amounts of revenues and expenses during the period. Actual results could differ from those estimates. During the periods presented, management has 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 PPAs, the recoverability of equity investments, the recoverability of future tax assets and the fair value of financial instruments and derivatives. The accounting policies that are most impacted by management estimates are related to financial instruments and impairment of long-lived assets and equity investments.

The Company's accounting policy related to financial instruments includes material non-cash income and losses related to changes in the fair value of derivative instruments, particularly the Chambers PPA and forward contracts for purchases of Canadian dollars to pay the Company's Canadian dollar obligations. Management's estimate of the fair value of the Chambers PPA at each balance sheet date is measured by comparing the net present value of the cash flows expected to be received under the terms of the PPA to the net present value of the cash flows that would be received if the same volumes were sold at projected market power prices over the term of the contract expiring in 2024. Changes in forward market conditions are sometimes significant from period to period and have a material impact on the estimated fair value of the PPA but do not directly impact the amount of cash flow the Chambers Project will receive under the terms of the PPA.

The Company's accounting policy for impairment of long-lived assets and equity investments requires management to periodically assess whether changes in events or circumstances at an operating Project or equity investment require an impairment test. When management determines that an impairment test is required, the future projected cash flows from the operating Project or equity investment are the most significant factor in determining whether an impairment exists and, if so, the amount of the impairment charge. Management uses its best estimates of market prices of power and fuel and its knowledge of the operations of the Project and its 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 management's assessment of the risk related to 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. No significant changes in the method used to make accounting estimates have occurred since December 31, 2009.

CHANGES IN ACCOUNTING POLICIES

INTERNATIONAL FINANCIAL REPORTING STANDARDS

In February 2008, the Canadian Accounting Standards Board announced the adoption of International Financial Reporting Standards ("IFRS") for publicly accountable enterprises in Canada. The CICA indicated that Canadian entities will be required to begin reporting under IFRS effective the first quarter of 2011 including comparative figures.

The Company has disclosed its intent to list its shares on the NYSE in the second quarter of 2010. This listing will require the Company to file periodic reports with the U.S. Securities and Exchange Commission ("SEC") using U.S. GAAP. Management intends to file its future U.S. GAAP financial statements and other SEC filings in Canada in lieu of financial statements presented in accordance with IFRS.

GOODWILL AND INTANGIBLE ASSETS

Effective January 1, 2009, the Company adopted the new CICA Handbook Section 3064, Goodwill and Intangible Assets, which establishes standards for recognition, measurement, presentation and disclosure of goodwill, subsequent to its initial recognition, and of intangible assets. Standards concerning goodwill are unchanged from the standards included in the previous CICA Handbook Section 3062. The adoption of this new standard did not have a material impact on the Company's consolidated financial statements.

CREDIT RISK AND FAIR VALUE OF FINANCIAL ASSETS AND LIABILITIES

In January 2009, the Company adopted the new Emerging Issues Committee ("EIC") EIC-173, Credit Risk and the Fair Value of Financial Assets and Financial Liabilities, which clarifies that an entity's own credit risk and the credit risk of the counterparty should be taken into account in determining the fair value of financial assets and liabilities, including derivative instruments. EIC-173 is to be applied retrospectively without restatement of prior periods in interim and annual financial statements for periods ending on or after the date of issuance of EIC-173. As a result of this change in accounting policy, the Company recorded adjustments to the values of certain of its derivative instruments as of January 1, 2009. These adjustments, net of taxes, decreased accumulated other comprehensive loss by $118, from $3,204 to $3,086, increased opening deficit by $1,977, decreased derivative instruments asset by $7, decreased the current portion of derivative instruments liability by $1,085 and decreased derivative instruments liability by $2,414.

RECENTLY ISSUED ACCOUNTING STANDARDS

In January 2009, the CICA issued CICA Handbook Section 1582, Business Combinations, Section 1601, Consolidations and Section 1602, Non-controlling Interests. These sections replace the former CICA Handbook Section 1581, Business Combinations and Section 1600, Consolidated Financial Statements and establish new standards for accounting for a non-controlling interest in a subsidiary.

CICA Handbook Section 1582 establishes standards for accounting for a business combination. It provides the Canadian equivalent to IFRS 3, Business Combinations (January 2008). The section applies prospectively to business combinations for which the acquisition date is on or after the beginning of the first annual reporting period beginning on or after January 1, 2011.

CICA Handbook Section 1601 establishes standards for the preparation of consolidated financial statements.

CICA Handbook Section 1602 establishes standards for accounting for a non-controlling interest in a subsidiary in consolidated financial statements subsequent to a business combination. It is the equivalent of the corresponding provisions of IFRS 27, Consolidated and Separate Financial Statements (January 2008).

CICA Handbook Section 1601 and Section 1602 apply to interim and annual consolidated financial statements relating to fiscal years beginning on or after January 1, 2011. Earlier adoption of these sections is permitted as of the beginning of a fiscal year. Section 1582, Section 1601 and Section 1602 must be adopted concurrently. The Company does not believe it will have a significant impact on its consolidated financial statements.

In June 2009, the CICA amended Handbook Section 3862, Financial Instruments – Disclosures, to adopt the amendments recently made by the International Accounting Standards Board to IFRS 7, Financial Instruments: Disclosures. The amendments require enhanced disclosures about fair value measurements, including the relative reliability of the inputs used in those measurements, and about the liquidity risk of financial instruments. Although the amendments apply to financial statements relating to fiscal years ending after December 31, 2009, comparative information is not required in the first year of application. The adoption of this new standard did not have a significant impact on the Company's consolidated financial statements.

DISCLOSURE CONTROLS AND PROCEDURES

Based on the requirements of Multilateral Instrument 52-109, Certification of Disclosure in Issuers' Annual and Interim Filings, the Chief Executive Officer and Chief Financial Officer of the Manager have evaluated the effectiveness of the Company's disclosure controls and procedures (as defined in Multilateral Instrument 52-109) as of December 31, 2009. Based on that evaluation, the Chief Executive Officer and Chief Financial Officer of the Manager have concluded that the Company's disclosure controls and procedures were effective as of December 31, 2009 to provide reasonable assurance that material information relating to the Company would be made known to them by others within the Company.

INTERNAL CONTROL OVER FINANCIAL REPORTING

Internal control over financial reporting ("ICFR") is designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements in accordance with Canadian GAAP. The Chief Executive Officer and Chief Financial Officer of the Manager evaluated the effectiveness of the Company's ICFR as of December 31, 2009 using the framework and criteria established by the Committee of Sponsoring Organizations of the Treadway Commission. Based on this evaluation, the Chief Executive Officer and Chief Financial Officer of the Manager concluded that the Company's ICFR was effective and that there were no material weaknesses in ICFR. There have been no material changes in the Company's ICFR during the three-month period ended December 31, 2009.

The CEO and CFO of the Manager have, as permitted by securities laws, limited the scope of design of ICFR to exclude the proportionately consolidated Badger Creek, Chambers, Koma Kulshan, Orlando, Onondaga Renewables and Topsham Projects.

RISK FACTORS

Atlantic Power's future performance and its ability to generate sufficient cash flow to meet its monthly dividends to shareholders and Debenture holders are subject to a number of risks and uncertainties. Any of these risks and uncertainties could have a material adverse effect on the Company's results of operations, business prospects, financial condition, the cash available to the Company for distribution to holders of common shares or Debentures, or the market price or value of its common shares or Debentures. A discussion of these risks and uncertainties can be found in the Company's annual information form dated March 29, 2010. The Company's annual information form is available on SEDAR's website at www.sedar.com.

ADDITIONAL INFORMATION

Additional information is available on the Company's website at www.atlanticpower.com, or under the Company's profile on the SEDAR website at www.sedar.com.

The tables on the following two pages present unaudited non-GAAP supplementary financial information provided for informational purposes. Please see "Non-GAAP Financial Measures" and "Results of Operations for the Three and Twelve Months Ended December 31, 2009 – Supplementary Financial Information" in this MD&A for additional details about the supplementary information.

PROJECT PORTFOLIO

The following table outlines the Company's portfolio of power generating and transmission assets as of March 29, 2010, including its interest in each facility. Management believes the portfolio is well diversified based on electricity and steam buyers, fuel type, regulatory jurisdictions and regional power pools, thereby partially mitigating exposure to market, regulatory or environmental conditions specific to any single region.

Project Name	Location (state)	Type	Total MW	Economic interest [1]	Accounting treatment [2]	Net MW [3]	Electricity purchaser	Power contract expiry	Customer S&P credit rating
Auburndale	Florida	Natural Gas	155	100.00%	C	155	Progress Energy Florida	2013	BBB+
Lake	Florida	Natural Gas	121	100.00%	C	121	Progress Energy Florida	2013	BBB+
Pasco	Florida	Natural Gas	121	100.00%	C	121	Tampa Electric Co.	2018	BBB
Chambers	New Jersey	Coal	262	40.00%	P	89	Atlantic City Electric [4]	2024	BBB
						16	DuPont	2024	A
Path 15	California	Transmission	N/A	100.00%	C	N/A	California Utilities via CAISO [5]	N/A [6]	BBB+ to A [7]
Orlando	Florida	Natural Gas	129	50.00%	P	46	Progress Energy Florida	2023	BBB+
						19	Reedy Creek Improvement District	2013[8]	A [9]
Selkirk	New York	Natural Gas	345	18.50% [10]	Cost	15	Merchant	N/A	N/A
						49	Consolidated Edison	2014	A–
Gregory	Texas	Natural Gas	400	17.10%	Cost	59	Fortis Energy Marketing and Trading	2013	A–
						9	Sherwin Alumina	2020	N/R
Topsham [11]	Maine	Hydro	14	50.00%	P	7	Central Maine Power	2011	BBB+
Badger Creek	California	Natural Gas	46	50.00%	P	23	Pacific Gas & Electric	2011	BBB+
Rumford	Maine	Coal/Biomass	85	23.50% [10]	E	20	Rumford Paper Co.	2010	N/R
Koma Kulshan	Washington	Hydro	13	49.80%	P	6	Puget Sound Energy	2037	BBB
Delta-Person	New Mexico	Natural Gas	132	40.00%	E	53	Public Service of New Mexico	2020	BB-

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

(2) Accounting Treatment: C – Consolidated; P – Proportionately Consolidated; E – Equity Method of Accounting; and "Cost" – Cost Method of Accounting (for additional details, see Note 1 to the Company's consolidated financial statements for the year ended December 31, 2009).

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

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

(5) California utilities pay Transmission Access Charges to CAISO, which then pays owners of Transmission Access Rights, such as Path 15, in accordance with its FERC-approved annual revenue requirement.

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

(7) Largest payers of Transmission Access Charges supporting Path 15's annual revenue requirement are PG&E (BBB+), SoCal Ed (BBB+) and SDG&E (A). CAISO imposes minimum credit quality requirements for any participants with ratings of A or better unless collateral is posted per CAISO imposed schedule.

(8) Upon the expiry of the Reedy Creek PPA, the associated capacity and energy will be sold to Progress Energy Florida.

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

(10) Represents our estimated share of the cash flow from the Project.

(11) The Company owns its interest in this Project as a lessor.

PROJECT ADJUSTED EBITDA [1]

(in thousands of U.S.dollars) (unaudited)	Three months ended December 31 2009	2008	Twelve months ended December 31 2009	2008
Adjusted EBITDA [1] from consolidated and proportionately consolidated Projects				
Auburndale	$ 6,967	$ 4,461	$ 35,221	$ 4,461
Badger Creek	781	1,098	3,245	3,762
Chambers	4,270	6,066	13,595	27,603
Koma Kulshan	347	259	822	912
Lake	4,628	7,830	25,378	32,892
Onondaga	–	(467)	–	7,865
Orlando	2,772	5,170	8,858	8,206
Pasco	184	4,660	3,299	21,953
Path 15	6,797	6,317	27,691	28,872
Topsham	346	958	1,879	2,629
Other	(212)	384	(432)	963
Total adjusted EBITDA [1] from consolidated and proportionately consolidated Projects	26,880	36,736	119,556	140,118
Amortization	13,692	11,011	55,847	43,563
Interest expense, net	5,882	6,526	23,361	23,193
Change in the fair value of derivative instruments	56,641	(78,028)	11,354	(55,348)
Other (income) expense	166	325	41	(5,138)
Income (loss) from consolidated and proportionately consolidated Projects	(49,501)	96,902	28,953	133,848
Adjusted EBITDA [1] from equity and cost method Projects				
Delta-Person	–	536	894	2,012
Gregory	828	1,478	2,240	10,411
Rumford	626	603	2,590	2,395
Selkirk	–	2,834	2,996	8,032
Other	(93)	–	(234)	(165)
Total adjusted EBITDA [1] from equity and cost method Projects	1,361	5,451	8,486	22,685
Amortization	(71)	455	323	1,824
Interest expense, net	15	191	240	727
Other expense	–	–	5,404	–
Income from equity and cost method Projects	1,417	4,805	2,519	20,134
Project income				
Total adjusted EBITDA [1] from all Projects	28,241	42,187	128,042	162,803
Amortization	13,621	11,466	56,170	45,387
Interest expense, net	5,897	6,717	23,601	23,920
Change in the fair value of derivative instruments	56,641	(78,028)	11,354	(55,348)
Other (income) expense	166	325	5,445	(5,138)
Project (loss) income as reported in the statement of income	(48,084)	101,707	31,472	153,982
Income from consolidated and proportionately consolidated Projects	(49,501)	96,902	28,953	133,848
Income from equity and cost method Projects	1,417	4,805	2,519	20,134
Project (loss) income as reported in the statement of income	$ (48,084)	$ 101,707	$ 31,472	$ 153,982

(1) Adjusted EBITDA is defined as income from continuing operations less interest, taxes, depreciation and amortization (including non-cash impairment charges) and changes in fair value of derivative instruments. 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 issuers. Management uses unaudited Adjusted EBITDA at the Projects to provide comparative information about Project performance. Investors are cautioned that the Company may calculate this measure in a manner that is different from other companies.

RECONCILIATION OF PROJECT DISTRIBUTIONS

For the twelve months ended December 31, 2009

(in thousands of U.S. dollars)	Adjusted EBITDA [1]	Repayment of long-term debt	Interest expense, net	Capital expenditures	Change in working capital and other items	Project distribution received
Consolidated and proportionately consolidated Projects						
Auburndale	$ 35,221	$ (3,500)	$ (2,832)	$ (322)	$ 2,419	$ 30,986
Badger Creek	3,245	–	(17)	–	447	3,675
Chambers	13,595	(10,570)	(7,674)	(688)	5,337	–
Koma Kulshan	822	–	1	(79)	(553)	191
Lake	25,378	–	4	(1,278)	(1,405)	22,699
Orlando	8,858	–	14	(632)	4,435	12,675
Pasco	3,299	–	–	(188)	5,239	8,350
Topsham	1,879	(45)	(2)	–	–	1,832
Path 1527,691	(7,518)	(12,912)	–	3,797	11,058	
Other	(432)	–	57	86	669	380
Total consolidated and proportionately consolidated Projects	119,556	(21,633)	(23,361)	(3,101)	20,385	91,846
Equity and cost method Projects						
Delta-Person	894	(1,512)	(224)	–	842	–
Gregory	2,240	(2,903)	(1,094)	(98)	4,095	2,240
Rumford	2,590	–	2	–	309	2,901
Selkirk	2,996	(8,122)	(1,936)	161	9,897	2,996
Other	(234)	–	(18)	–	429	177
Total equity and cost method Projects	8,486	(12,537)	(3,270)	63	15,572	8,314
Total all Projects	**$ 128,042**	**$ (34,170)**	**$ (26,631)**	**$ (3,038)**	**$ 35,957**	**$ 100,160**

(1) Adjusted EBITDA is defined as income from continuing operations less interest, taxes, depreciation and amortization (including non-cash impairment charges) and changes in fair value of derivative instruments. 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 issuers. Management uses unaudited Adjusted EBITDA at the Projects to provide comparative information about Project performance. Investors are cautioned that the Company may calculate this measure in a manner that is different from other companies.

Management's Responsibility for Financial Statements

The accompanying consolidated financial statements of Atlantic Power Corporation, the management's discussion and analysis and the information included in this annual report have been prepared by the Corporation's management, which is responsible for their consistency, integrity and objectivity. Management is also responsible for ensuring that the consolidated financial statements are prepared and presented in accordance with Canadian generally accepted accounting principles, which include amounts that are based on estimates and judgments. To fulfill these responsibilities, management maintains appropriate internal control systems and policies and procedures to provide reasonable assurance that assets are safeguarded and financial records are reliable and form a proper basis for the preparation of financial statements.

KPMG LLP, the Corporation's independent auditors, are responsible for auditing the consolidated financial statements in accordance with Canadian generally accepted auditing standards, and have expressed their opinion on the consolidated financial statements in this report. Their report, as auditors, is set forth below.

The Corporation's Board of Directors is responsible for ensuring that management fulfills its responsibilities for financial reporting and internal controls. The Board of Directors carries out this responsibility through its Audit Committee, which meets regularly with management and the independent auditors. The members of the Audit Committee are independent of management. The consolidated financial statements have been reviewed and approved by the Board of Directors and its Audit Committee. The independent auditors have direct and full access to the Audit Committee and the Board of Directors.

Barry Welch	Patrick Welch
President and Chief Executive Officer	Chief Financial Officer

Auditors' Report to the Shareholders

We have audited the consolidated balance sheets of Atlantic Power Corporation as at December 31, 2009 and 2008 and the consolidated statements of income (loss) and deficit, comprehensive income (loss) and cash flows for the years then ended. 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 in accordance with Canadian generally accepted auditing standards. Those standards require that we plan and perform an audit to obtain reasonable assurance 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.

In our opinion, these consolidated financial statements present fairly, in all material respects, the financial position of the Company as at December 31, 2009 and 2008 and the results of its operations and its cash flows for the years then ended in accordance with Canadian generally accepted accounting principles.

KPMG LLP

Chartered Accountants, Licensed Public Accountants
Toronto, Canada
March 29, 2010

Consolidated Balance Sheets

(in thousands of U.S. dollars)

As at December 31	2009	2008
ASSETS		
Current assets:		
Cash and cash equivalents	$ 54,503	$ 42,566
Restricted cash	17,381	32,877
Accounts receivable	28,374	48,128
Current portion of derivative instruments asset (Note 12)	32,523	15,001
Prepayments, supplies and other	6,006	8,593
Income taxes recoverable	10,553	2,300
	149,340	149,465
Property, plant and equipment (Note 5)	367,410	433,542
Transmission system rights (Note 6)	195,984	203,833
Other intangible assets (Note 6)	148,155	180,186
Long-term investments (Note 7)	61,037	63,765
Goodwill	8,918	8,918
Derivative instruments asset (Note 12)	104,868	109,482
Other assets	1,840	2,399
	$ 1,037,552	$ 1,151,590
LIABILITIES AND SHAREHOLDERS' EQUITY		
Current liabilities:		
Accounts payable and accrued liabilities	$ 32,494	$ 31,783
Current portion of long-term and short-term debt	29,331	79,512
Current portion of derivative instruments liability (Note 12)	8,852	10,031
Interest payable on Subordinated Notes and Debentures	800	3,455
Dividends payable	5,242	1,918
Other	752	3,941
	77,471	130,640
Long-term debt (Note 9)	297,652	364,155
Subordinated Notes (Note 10)	–	310,584
Convertible debentures (Note 11)	135,090	48,790
Derivative instruments liability (Note 12)	7,450	22,132
Future tax liability (Note 14)	13,344	44,883
Other liabilities	26,862	35,467
Shareholders' equity:		
Common stock (Note 15)	541,304	214,888
Accumulated other comprehensive loss (Note 18)	(859)	(3,204)
Deficit	(60,762)	(16,745)
	479,683	194,939
Commitments and contingencies (Note 20)		
Subsequent events (Notes 3 and 23)		
	$ 1,037,552	$ 1,151,590

See accompanying notes to consolidated financial statements.

On behalf of the Board:

Ken Hartwick
Director

Irving Gerstein
Director

Consolidated Statements of Income (Loss), Comprehensive Income (Loss) and Deficit

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

Years ended December 31	2009	2008
Project revenue:		
Energy sales	$ 111,356	$ 132,511
Energy capacity revenue	135,253	123,466
Transmission services	31,001	31,528
Other	10,671	14,067
	288,281	301,572
Project expenses:		
Fuel	113,458	116,518
Operations and maintenance	46,911	36,851
Project operator fees and expenses	8,356	8,085
Depreciation and amortization	55,847	43,563
	224,572	205,017
Project other income (expense):		
Change in fair value of derivative instruments (Note 12)	(11,354)	55,348
Income from long-term investments	2,519	20,134
Interest, net	(23,361)	(23,193)
Other project income (expense)	(41)	5,138
	(32,237)	57,427
Project income	31,472	153,982
Administrative and other expenses (income):		
Management fees and administration	26,028	10,012
Interest, net	55,665	43,275
Foreign exchange loss (gain) (Note 12)	20,506	(44,692)
Other expense, net	361	424
	102,560	9,019
(Loss) income from continuing operations before income taxes	(71,088)	144,963
Income tax expense (benefit) (Note 14)	(46,551)	21,224
(Loss) income from continuing operations	(24,537)	123,739
Income (loss) from discontinued operations, net of tax (Note 21)	6,264	(13,051)
Net (loss) income	$ (18,273)	$ 110,688
Other comprehensive income:		
Cumulative impact of implementing new accounting standards (Note 2)	118	–
Unrealized gain (loss) on cash flow hedges, net of taxes	2,227	(3,204)
Comprehensive (loss) income	$ (15,928)	$ 107,484
(Loss) income from continuing operations per share – basic (Note 17)	$ (0.40)	$ 2.02
Income (loss) from discontinued operations per share – basic (Note 17)	0.10	(0.21)
Net (loss) income per share – basic (Note 17)	$ (0.30)	$ 1.81
(Loss) income from continuing operations per share – diluted (Note 17)	$ (0.40)	$ 1.87
Income (loss) from discontinued operations per share – diluted (Note 17)	0.10	(0.20)
Net (loss) income per share – diluted (Note 17)	$ (0.30)	$ 1.67
Net (loss) income	$ (18,273)	$ 110,688
Deficit, beginning of period	(16,745)	(102,861)
Cumulative impact of implementing new accounting standard (Note 2)	1,977	–
Redemption of IPSs (Note 15)	339	275
Dividends declared	(28,060)	(24,847)
Deficit, end of period	$ (60,762)	$ (16,745)

See accompanying notes to consolidated financial statements.

Consolidated Statements of Cash Flows

(in thousands of U.S. dollars)

Years ended December 31	2009	2008
CASH FLOWS FROM OPERATING ACTIVITIES		
Net (loss) income from continuing operations	$ (24,537)	$ 123,739
Items not involving cash:		
Depreciation and amortization	55,847	43,563
Asset impairment (Note 3)	5,500	–
Loss (gain) on sale of property, plant and equipment	933	(5,163)
Earnings from equity investments (Note 7)	(2,782)	(1,692)
Unrealized foreign exchange (gain) loss (Note 12)	24,370	(36,648)
Change in fair value of Subordinated Note prepayment option (Note 12)	106	27
Change in fair value of derivative instruments (Note 12)	11,354	(55,348)
Future taxes	(38,595)	21,236
Change in other operating balances:		
Restricted cash	3,514	5,498
Accounts receivable	15,404	(1,073)
Prepayment and other assets	(8,976)	(4,003)
Accounts payable and accrued liabilities	5,843	(2,904)
Other liabilities	4,517	7,404
Distributions from equity investments	3,078	2,742
Subordinated Note redemption premium recorded in interest expense	1,935	–
Common Share Conversion costs recorded in interest expense	4,508	–
Cash provided by operating activities of continuing operations	62,019	97,378
Cash provided by operating activities of discontinued operations	470	2,360
	62,489	99,738
CASH FLOWS (USED IN) PROVIDED BY FINANCING ACTIVITIES		
Redemption of IPSs	(3,369)	(4,676)
Redemption of Subordinated Notes	(40,638)	–
Costs associated with Common Share Conversion	(4,508)	–
Dividends paid	(24,955)	(24,612)
Proceeds from convertible debentures	82,065	–
Deferred financing costs associated with convertible debentures	(3,735)	–
Repayment of revolving credit facility borrowings	(55,000)	–
Proceeds from revolving credit facility borrowings	–	55,000
Proceeds from issuance of project-level debt	–	35,000
Repayment of long-term debt	(21,633)	(35,631)
Cash (used in) provided by financing activities of continuing operations	(71,773)	25,081
Cash (used in) financing activities of discontinued operations	(1,853)	(2,646)
	(73,626)	22,435
CASH FLOWS PROVIDED BY (USED IN) INVESTING ACTIVITIES		
Investment in Rollcast Energy (Note 3)	(3,068)	–
Acquisition of Auburndale, net of cash acquired (Note 3)	–	(141,688)
Proceeds from sale of property, plant and equipment	477	7,889
Purchases of property, plant and equipment	(3,635)	(1,749)
Cash used in investing activities of continuing operations	(6,226)	(135,548)
Cash provided by (used in) investing activities of discontinued operations	29,300	(49)
	23,074	(135,597)
Increase (decrease) in cash and cash equivalents	11,937	(13,424)
Cash and cash equivalents, beginning of period	42,566	55,990
Cash and cash equivalents, end of period	$ 54,503	$ 42,566
SUPPLEMENTAL CASH FLOW INFORMATION		
Interest paid	$ 69,186	$ 72,129
Income taxes (paid) refunded	$ (216)	$ 2,418

See accompanying notes to consolidated financial statements.

Notes to the Consolidated Financial Statements

Years ended December 31, 2009 and 2008

(in thousands of U.S. dollars, unless otherwise noted, except per share amounts)

Atlantic Power Corporation (the "Company") is a corporation established under the laws of the Province of Ontario on June 18, 2004 and continued to the Province of British Columbia on July 8, 2005. The Company issued income participating securities ("IPSs") for cash pursuant to an initial public offering on November 18, 2004. Each IPS was comprised of one common share and Cdn$5.767 principal value of 11% subordinated notes due 2016 ("Subordinated Notes"). On November 24, 2009, the shareholders approved a conversion from the Company's IPS Structure to a traditional common share structure (the "Common Share Conversion"). Each IPS has been exchanged for one new common share of the Company and any old common shares of the Company that did not form a part of an IPS were exchanged for approximately 0.44 of a new common share of the Company.

The Company currently owns, through its wholly-owned subsidiaries Atlantic Power Generation, Inc. and Atlantic Power Transmission, Inc., indirect interests in 12 power generation projects and one transmission line located in the United States (collectively, the "Projects"). Four of the Projects are wholly-owned subsidiaries of the Company: Lake Cogen Ltd. ("Lake"), Pasco Cogen, Ltd. ("Pasco"), Auburndale Power Partners, L.P. ("Auburndale") and Atlantic Path 15, LLC ("Path 15").

1 • BASIS OF PRESENTATION AND SIGNIFICANT ACCOUNTING POLICIES

(a) Basis of presentation

The consolidated financial statements of the Company are prepared in accordance with Canadian generally accepted accounting principles and include the consolidated accounts of all of its subsidiaries. The Company applies the equity method of accounting for investments in which it has significant influence but which it does not control and applies the cost method of accounting for investments in which it does not have significant influence, as these are treated as available for sale instruments for which there is no available market and as such are recorded at cost (Note 7). The Company proportionately consolidates investments in which it has joint control (Note 4). The Company eliminates intercompany accounts and transactions in consolidation.

(b) Cash and cash equivalents

Cash and cash equivalents include cash deposited at banks and highly liquid investments with original maturities of three months or less.

(c) Restricted cash

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

(d) 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. The useful lives of facilities range from three to 60 years. The weighted average useful life is 23 years.

(e) 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 the Path 15 Project.

(f) 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 the Company's reporting units that are expected to benefit from the synergies of the business combination.

Goodwill is not amortized and is tested for impairment annually 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 income (loss), comprehensive income (loss) and deficit.

Goodwill at December 31, 2009 and 2008 relates to the Path 15 segment.

(g) Other intangible assets

Other intangible assets include power purchase agreements ("PPA") and fuel supply agreements at the Company's Projects.

PPAs are valued at the time of acquisition based on the prices received under the PPA compared to projected market prices. The balances are presented net of accumulated amortization in the consolidated balance sheets. Amortization is recorded on a straight-line basis over the remaining term of the PPA. The amortization period ranges from one to 16 years. The weighted average period of remaining amortization is eight years.

Fuel supply agreements are valued at the time of acquisition based on the prices projected to be paid under the fuel supply agreement relative to projected market prices. The amortization period ranges from one to 16 years. The weighted average period of remaining amortization is nine years.

(h) Revenue recognition

The Company recognizes energy sales revenue when electricity and steam are delivered under the terms of the related contracts. Revenue associated with capacity payments under the PPAs is recognized as the lesser of (1) the amount billable under the PPA or (2) an amount determined by the kilowatt hours ("kWhs") made available during the period multiplied by the estimated average revenue per kWh 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.

(i) Income taxes

Income taxes are accounted for using the asset and liability method. Future tax assets and liabilities are recognized for the future tax consequences attributable to differences between the financial statement carrying amounts of existing assets and liabilities and their respective tax bases. Future tax assets and liabilities are measured using enacted or substantively enacted tax rates expected to apply to taxable income in the years in which those temporary differences are expected to be recovered or settled. The effect on future tax assets and liabilities of a change in tax rates is recognized in income in the year that includes the date of enactment or substantive enactment.

A valuation allowance is recorded against future tax assets to the extent that it is more likely than not that the future tax asset will not be realized.

(j) Financial instruments

Financial instruments are required to be measured at fair value on initial recognition. Measurement in subsequent periods is based on the classification of the financial instrument. Financial assets and financial liabilities held for trading are measured at fair value with changes in fair value reported in earnings. Financial assets held to maturity, loans and receivables and financial liabilities other than those held for trading are measured at amortized cost using the effective interest method. Available for sale financial assets are measured at fair value with changes in fair value reported in other comprehensive income until the financial instrument is de-recognized, at which time the cumulative gain or loss previously recognized in accumulated other comprehensive income is recognized in net income for the period.

The Company uses financial derivative agreements in the form of interest rate swaps, indexed swap hedges and foreign exchange forward contracts to manage its current and anticipated exposure to fluctuations in interest rates and foreign currency exchange rates. On occasion, the Company has 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. The Company does not enter into financial derivative agreements for trading or speculative purposes; however, not all derivatives qualify for hedge accounting.

Derivative financial instruments not designated as hedges are measured at fair value, with changes in fair value recorded in the consolidated statements of income (loss), comprehensive income (loss) and deficit.

The following table summarizes derivative financial instruments that are not designated as hedges and the accounting treatment in the consolidated statements of income (loss), comprehensive income (loss) and deficit of the changes in fair value of each such derivative financial instrument:

Derivative financial instrument	Accounting treatment for changes in fair value
Chambers PPA	Change in fair value of derivative instruments
Foreign currency forward contracts	Foreign exchange loss (gain)
Lake natural gas swaps	Change in fair value of derivative instruments
Auburndale natural gas swaps	Change in fair value of derivative instruments
Interest rate swap	Change in fair value of derivative instruments
Onondaga indexed swap and indexed swap hedges	Change in fair value of derivative instruments

Fuel supply contracts in the normal course of business, in which the Company takes possession of the fuel commodity, are treated as executory contracts, which are expensed as incurred.

The Company has designated some of its interest rate swaps as hedges 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. The ineffective portion of interest rate swaps within a designated hedging relationship is recorded in the consolidated statements of income (loss), comprehensive income (loss) and deficit. Unrealized gains or losses on the interest rate swaps within a designated hedging relationship are recognized in other comprehensive income.

(k) Asset retirement obligations

The fair value of asset retirement obligations is recognized in other long-term liabilities in the consolidated balance sheets when they are identified and their fair value is reasonably estimable. The asset retirement cost, equal to the estimated fair value of the asset retirement obligation, is capitalized as part of the cost of the related long-lived asset. The asset retirement costs are depreciated over the related asset's estimated useful life and included in depreciation expense on the consolidated statements of income (loss), comprehensive income (loss) and deficit. Increases in the asset retirement obligation resulting from the passage of time are recorded as accretion of asset retirement obligation in the consolidated statements of income (loss), comprehensive income (loss) and deficit. Actual expenditures incurred to retire the asset are charged against the accumulated obligation.

(l) Impairment of long-lived assets and equity and cost 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.

The Company evaluates its equity and cost method investments to determine whether or not they are impaired when a decline in value is considered “other than temporary.”

(m) Foreign currency translation

The Company’s functional currency and reporting currency is the United States dollar. The functional currency of the Company’s 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 year. All transactions denominated in Canadian dollars are translated into United States dollars at average exchange rates. Foreign currency translation gains and losses are reflected in the consolidated statements of income (loss), comprehensive income (loss) and deficit.

(n) Use of estimates

The preparation of financial statements requires management 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, management has 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 PPAs, the recoverability of long-term investments, the recoverability of future tax assets, and the fair value of financial instruments and derivatives. These estimates and valuation assumptions are based on present conditions and management’s planned course of action, as well as assumptions about future business and economic conditions. Should the underlying valuation assumptions and estimates change, the recorded amounts could change by a material amount.

(o) Long-term incentive plan

The officers and other employees of the Company are eligible to participate in the Company’s Long-Term Incentive Plan (“LTIP”) that was implemented in 2007 and continued in effect until the end of 2009. On an annual basis, the Board of Directors establishes awards that are based on the cash flow performance of the Company in the most recently completed year, each participant’s base salary and the market price of the common shares at the award date. Awards are granted in the form of notional units that have similar economic characteristics to the Company’s common shares. Notional units vest over a three-year period and are redeemed in a combination of cash and common shares upon vesting.

Unvested notional awards are entitled to receive distributions equal to the distributions per public common share during the vesting period in the form of additional notional units. Unvested awards are subject to forfeiture if the participant is not an employee of the Company at the vesting date or if the Company does 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 at each balance sheet date. Fair value of the awards is determined by projecting the total number of notional units that will vest in future periods, including distributions received on notional units during the vesting period, and applying the current market price per common share to the projected number of notional units that will vest. Forfeitures are recorded as they occur and are not included in the estimated fair value of the awards. The aggregate number of common shares which may be issued from treasury under the LTIP is limited to one million.

In early 2010, the Board of Directors approved an amendment to LTIP. The amended LTIP will be effective for grants beginning with the 2010 performance year. See Note 16 for additional information.

2 • CHANGES IN ACCOUNTING POLICIES

(a) Goodwill and intangible assets

Effective January 1, 2009, the Company adopted the new CICA Handbook Section 3064, Goodwill and Intangible Assets, which establishes standards for recognition, measurement, presentation and disclosure of goodwill subsequent to its initial recognition and of intangible assets. Standards concerning goodwill are unchanged from the standards included in the previous CICA Handbook Section 3062. The adoption of this new standard did not have a material impact on the Company’s consolidated financial statements.

(b) Credit risk and fair value of financial assets and liabilities

In January 2009, the Company adopted the new Emerging Issues Committee (“EIC”) EIC-173, Credit Risk and the Fair Value of Financial Assets and Financial Liabilities, which clarifies that an entity’s own credit risk and the credit risk of the counterparty should be taken into account in determining the fair value of financial assets and liabilities, including derivative instruments. EIC-173 is to be applied retrospectively without restatement of prior periods in interim and annual financial statements for periods ending on or after the date of issuance of EIC-173. As a result of this change in accounting policy, the Company recorded adjustments to the values of certain of its derivative instruments as of January 1, 2009. These adjustments, net of taxes, decreased accumulated other comprehensive loss by $118, from $3,204 to $3,086, increased opening deficit by $1,977, decreased derivative instruments asset by $7, decreased the current portion of derivative instruments liability by $1,085 and decreased derivative instruments liability by $2,414.

(c) Recently issued accounting standards

In January 2009, the CICA issued CICA Handbook Section 1582, Business Combinations, Section 1601, Consolidations and Section 1602, Non-controlling Interests. These sections replace the former CICA Handbook Section 1581, Business Combinations and Section 1600, Consolidated Financial Statements and establish a new section for accounting for a non-controlling interest in a subsidiary.

CICA Handbook Section 1582 establishes standards for accounting for a business combination. It provides the Canadian equivalent to International Financial Reporting Standard (“IFRS”) 3, Business Combinations (January 2008). The section applies prospectively to business combinations for which the acquisition date is on or after the beginning of the first annual reporting period beginning on or after January 1, 2011.

CICA Handbook Section 1601 establishes standards for the preparation of consolidated financial statements.

CICA Handbook Section 1602 establishes standards for accounting for a non-controlling interest in a subsidiary in consolidated financial statements subsequent to a business combination. It is the equivalent of the corresponding provisions of IFRS 27, Consolidated and Separate Financial Statements (January 2008).

CICA Handbook Section 1601 and Section 1602 apply to interim and annual consolidated financial statements relating to fiscal years beginning on or after January 1, 2011. Earlier adoption of these sections is permitted as of the beginning of a fiscal year. Section 1582, Section 1601 and Section 1602 must be adopted concurrently. The Company does not believe this will have a significant impact on its consolidated financial statements.

In June 2009, the CICA amended Handbook Section 3862, Financial Instruments – Disclosures, to adopt the amendments recently made by the International Accounting Standards Board to IFRS 7, Financial Instruments: Disclosures. The amendments require enhanced disclosures about fair value measurements, including the relative reliability of the inputs used in those measurements, and about the liquidity risk of financial instruments. Although the amendments apply to financial statements relating to fiscal years ending after December 31, 2009, comparative information is not required in the first year of application. The additional disclosures required by this amendment have been included in Note 12 to the Company's consolidated financial statements.

3 • ACQUISITIONS AND DISPOSITIONS

(a) Stockton sale

On November 30, 2009, the Company sold its 50% interest in the assets of Stockton Cogeneration Company L.P. ("Stockton") 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, the Company recorded a loss on the sale of $2,046. The loss on sale and the results of Stockton's operations have been reclassified to discontinued operations in the accompanying consolidated financial statements.

(b) Mid-Georgia sale

On November 24, 2009, the Company sold its 50% interest in the assets of Mid-Georgia Cogeneration L.P. ("Mid-Georgia") for $29,100. Mid-Georgia is a 308 MW dual-fueled, combined-cycle cogeneration plant located in Kathleen, Georgia. During the year ended December 31, 2009, the Company recorded a gain on sale of its interest in the assets of Mid-Georgia of $15,826. The gain on sale and the results of Mid-Georgia's operations have been reclassified to discontinued operations in the accompanying consolidated financial statements.

(c) Rumford

During the three-month period ended September 30, 2009, management reviewed the recoverability of its 23.5% equity investment in the Rumford Project, an 85 MW coal/biomass plant located in Rumford, Maine. The review was undertaken as a result of not receiving distributions from the Project through the first nine months of 2009 and management's 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, management determined that the carrying value of the Rumford Project was impaired and recorded a pre-tax long-lived asset impairment of $5,500 during 2009. The Rumford Project is accounted for under the equity method of accounting and the impairment charge is included in income (loss) from long-term investments in the consolidated statements of income (loss), comprehensive income (loss) and deficit.

In the fourth quarter of 2009, the Company and the other limited partners in the Rumford Project settled a dispute with the general partner related to the general partners' failure to pay distributions to the limited partners in 2009. Under the terms of the settlement, the Company received $2,901 in distributions from Rumford in the fourth quarter of 2009.

In addition, the general partner has agreed to purchase the interests of all the limited partners in 2010. However, the general partner is relieved of this obligation if it announces before June 30, 2010, the closure of its paper mill located adjacent to the Rumford Project. If the general partner does purchase the limited partners' interests, the Company's share of the proceeds will be approximately $2,500. The carrying value of the Company's investment in Rumford as of December 31, 2009 is $845.

(d) Rollcast

On March 31, 2009, the Company acquired a 40% equity interest in Rollcast Energy, Inc., ("Rollcast") a North Carolina corporation. Rollcast is a developer of biomass power plants in the southeastern U.S. with five 50 MW projects in various stages of development. The investment in Rollcast gives the Company the option but not the obligation to invest equity in Rollcast's biomass power plants. Two of Rollcast's development projects have secured 20-year PPAs with terms that allow for fuel cost pass-through to the utility off-taker. Total cash paid for the investment was $3 million and is accounted for under the equity method of accounting.

In March 2010, the Company agreed to invest an additional $2.0 million to increase its 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 will be payable if Rollcast achieves certain milestones on its first biomass development project. As a result of this additional investment, the Company will begin to consolidate its investment in Rollcast beginning in March 2010.

(e) Onondaga Renewables

In the first quarter of 2009, the Company transferred its 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. The Company proportionately consolidates its investment in Onondaga Renewables.

(f) Auburndale acquisition

On November 21, 2008, the Company acquired 100% of Auburndale, 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 the Company's credit facility and $35 million of acquisition debt. The cash payment for the acquisition, including acquisition costs, has been allocated to the net assets acquired based on management's preliminary estimate of the fair value.

During 2009, management revised its initial estimate of the restricted cash balance at the time of the Auburndale acquisition. The revised estimate was recorded as an increase to restricted cash and a decrease to cash and cash equivalents in the amount of $7,505 in the consolidated balance sheet as of December 31, 2008.

The allocation of the purchase price to the net assets acquired was 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 • JOINT VENTURE INVESTMENTS

The Company accounts for six entities under proportionate consolidation as of December 31, 2009:

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

The following summarizes the balance sheets at December 31, 2009 and 2008, and operating results and distributions paid to the Company for the years ended December 31, 2009 and 2008, for the Company's proportionate share of the six joint-venture entities:

	2009	2008
Assets		
Current assets	**$ 48,070**	$ 42,853
Non-current assets	**341,630**	372,341
	$ 389,700	$ 415,194
Liabilities		
Current liabilities	**$ 25,443**	$ 22,321
Non-current liabilities	**114,153**	91,253
	$ 139,596	$ 113,574
Operating results		
Revenue	**$ 108,762**	$ 127,762
Net income (loss)	**(194)**	95,480
Distributions paid to the Company	**$ 18,373**	$ 18,492

5 • PROPERTY, PLANT AND EQUIPMENT

	2009	2008
Land	**$ 2,593**	$ 2,423
Leasehold improvements	**4,068**	4,033
Machinery, equipment and other	**65,780**	72,858
Plant	**471,898**	541,230
	544,339	620,544
Less accumulated depreciation	**(176,929)**	(187,002)
	$ 367,410	$ 433,542

Depreciation expense of $17,769 and $15,801 was recorded for the years ended December 31, 2009 and 2008, respectively.

In 2008, management reviewed the recoverability of its investment in the Stockton Project. The review was undertaken as a result of the current status of negotiations to extend the Project's PPA and the recent deterioration of current and long-term market conditions for coal-fired generation assets in California, including the price of natural gas, which sets marginal electricity prices.

Based on this review, management determined that the carrying value of the Stockton Project would not be recovered and recorded a pre-tax long-lived asset impairment of $18,471, which represented the entire value of the Project's property, plant and equipment at December 31, 2008. The impairment charge is included in loss from discontinued operations in the consolidated statements of income (loss), comprehensive income (loss) and deficit. The Company sold the Project as of November 30, 2009. See Note 3(a) for further information on the sale of Stockton.

6 • OTHER INTANGIBLE ASSETS AND TRANSMISSION SYSTEM RIGHTS

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

Amortization expense of $39,880 and $33,123 was recorded for the years ended December 31, 2009 and 2008, respectively.

	2009	2008
Transmission system rights	**$ 231,669**	$ 231,669
Less accumulated amortization	**(35,685)**	(27,836)
	$ 195,984	$ 203,833
Power purchase agreements	**$ 126,488**	$ 126,488
Fuel supply agreements	**115,610**	115,610
Less accumulated amortization	**(93,943)**	(61,912)
	$ 148,155	$ 180,186

7 • LONG-TERM INVESTMENTS

The Company has investments accounted for under the equity method and the cost method. The entities under the equity method of accounting are Delta-Person Limited Partnership, Rumford Cogeneration Company LP and Rollcast. The entities under the cost method of accounting are Gregory Power Partners LP and Selkirk Cogen Partners LP. An analysis of the investments is presented below:

	2009	2008
Long-term investments, beginning of year	**$ 63,765**	$ 64,815
Investment in Rollcast (Note 3(d))	**3,068**	–
Equity earnings (loss),		
net of impairment charge of $5,500	**(2,718)**	1,692
Distributions received from equity investments	**(3,078)**	(2,742)
Long-term investments, end of year	**$ 61,037**	$ 63,765

8 • CREDIT FACILITY

The Company maintains 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.

In November 2008, the Company borrowed $55,000 under the credit facility and used the proceeds to partially fund the acquisition of Auburndale. The Company had executed an interest rate swap to fix the interest rate at 2.4% through November 2011 for the balance outstanding under this borrowing. During 2009, $55,000 of the outstanding borrowings under the credit facility was repaid with cash on hand, and the interest rate swap associated with this facility was terminated.

Outstanding amounts under the credit facility bear interest at the London Interbank Offered Rate ("LIBOR") plus an applicable margin between 1.50% and 3.25% that varies based on the credit ratio of a subsidiary of the Company. As of December 31, 2009, the applicable margin was 1.50% (0.875% in 2008). The Company amended the credit facility in order to facilitate the Common Share Conversion. Under the terms of the amendment, the Company paid a fee of $250 and changed the method of computing the applicable margin on amounts outstanding under the credit facility from cash flow ratios to cash flow and indebtedness ratios.

As of December 31, 2009, $43,855 was allocated, but not drawn, to support letters of credit for contractual credit support at seven of the Company's Projects.

The Company must meet certain financial covenants under the terms of the credit facility, which are generally based on the Company's cash flow coverage ratio and indebtedness ratios. The facility is secured by pledges of assets and interests in certain subsidiaries. The Company expects to remain in compliance with the covenants of the credit facility for at least the next twelve months.

9 • LONG-TERM DEBT

Long-term debt represents the Company's consolidated and proportionately consolidated share of Project long-term debt 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 the Company and generally amortizes during the term of the respective revenue-generating contracts of the Projects.

	2009	2008
Project debt, interest rates ranging from		
0.4% to 9.0% maturing through 2028	**$ 316,425**	$ 377,719
Plus: purchase accounting		
fair value adjustments	**17,973**	19,257
Less: deferred financing costs	**(7,415)**	(8,309)
Less: current portion of long-term debt	**(29,331)**	(24,512)
Long-term debt	**$ 297,652**	$ 364,155

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

2010	$ 29,331
2011	30,581
2012	29,343
2013	28,085
2014	18,845
Thereafter	180,240
	$ 316,425

The debt of joint ventures is secured by the respective facility and its contracts with no other recourse to the Company. The loans have certain financial covenants that must be met. At December 31, 2009, all of the Company's Projects were in compliance with the covenants contained in Project-level debt. All of the debt in the table above is represented by non-recourse debt of the Projects.

10 • SUBORDINATED NOTES

	2009	2008
Subordinated notes (2008 – Cdn$390,946)	**$ –**	$ 320,974
Less deferred financing costs	**–**	(10,390)
	$ –	$ 310,584

On November 27, 2009, the shareholders approved a conversion from the Company's IPS Structure to a traditional common share structure. Each IPS has been exchanged for one new common share of the Company and any old common shares of the Company that did not form part of an IPS were exchanged for approximately 0.44 of a new common share of the Company. This transaction resulted in the extinguishment of Cdn$347,832 principal value of Subordinated Notes.

A loss on the Common Share Conversion in the amount of $13,069 was recorded in interest expense within administrative and other expenses and was comprised of the write-off of unamortized deferred financing costs of $7,507, the costs associated with the Common Share Conversion of $4,704 and the write-off of the unamortized Subordinated Note premium of $858.

On December 17, 2009, the Company exercised its Subordinated Note Call Option to redeem the remaining Cdn$40,677 principal value of Subordinated Notes at 105% of the principal amount. A loss on the redemption of the Subordinated Notes in the amount of $3,175 was recorded in interest expense within administrative and other expenses and was comprised of the write-off of unamortized deferred financing costs of $1,240 and the 5% premium paid in the amount of $1,935.

The Subordinated Notes were due to mature in November 2016 subject to redemption under specified conditions at the option of the Company, commencing on or after November 18, 2009 (Note 12(c)). 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 the Company's interest in Holdings and certain subsidiaries, and contained certain restrictive covenants. Subordinated Notes with Cdn$39,501 principal value were separately held by two investors and the remaining amount of the outstanding Subordinated Notes formed a part of the Company's publicly traded IPSs.

Interest expense related to the Subordinated Notes was $36,365 and $40,169 for the years ended December 31, 2009 and 2008, respectively.

11 • CONVERTIBLE DEBENTURES

On October 11, 2006, the Company issued, in a public offering, Cdn$60,000 ($57,088 at December 31, 2009 and $48,790 at December 31, 2008) aggregate principal amount of 6.25% convertible secured debentures (the "2006 Debentures") for gross proceeds of $52,780. The 2006 Debentures pay interest semi-annually on April 30 and October 31 of each year. The 2006 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.

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.

On December 17, 2009, the Company issued, in a public offering, Cdn$75,000 ($68,054, net of deferred financing costs, at December 31, 2009) aggregate principal amount of 6.25% convertible debentures (the "2009 Debentures") for gross proceeds of $71,361. 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.

On December 24, 2009, the underwriters exercised their over-allotment option in full to purchase an additional Cdn$11,250 ($10,276, net of deferred financing costs, at December 31, 2009) aggregate principal amount of the 2009 Debentures for gross proceeds of $10,704.

Aggregate interest expense for the 2006 Debentures and the 2009 Debentures was $3,522 and $3,490 for the years ended December 31, 2009 and 2008, respectively.

12 • FINANCIAL INSTRUMENTS

The financial instruments of the Company 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 fair value hierarchy of the Company's financial assets and liabilities that were recognized at fair value as of December 31, 2009 and December 31, 2008. Financial assets and liabilities are classified based on the lowest level of input that is significant to the fair value measurement.

December 31, 2009	Level 1	Level 2	Level 3	Total
Assets:				
Derivative assets	$ –	$ 137,391	$ –	$ 137,391
Liabilities:				
Derivative liabilities	–	16,302	–	16,302
Total	$ –	$ 121,089	$ –	$ 121,089

December 31,2008	Level 1	Level 2	Level 3	Total
Assets:				
Derivative assets	$ –	$ 124,483	$ –	$ 124,483
Liabilities:				
Derivative liabilities	–	32,163	–	32,163
Total	$ –	$ 92,320	$ –	$ 92,320

(a) Classification of financial instruments

The following table contains the carrying value and classification of the Company's financial instruments as of December 31, 2009 and 2008:

		2009		2008
Financial assets:				
Held for trading, measured at fair value:				
Cash and cash equivalents	$	54,503	$	42,566
Restricted cash		17,381		32,877
Current portion of derivative instruments asset		32,523		15,001
Derivative instruments asset		104,868		109,482
Loans and receivables, measured at amortized cost:				
Accounts receivable	$	28,374	$	48,128
Income tax recoverable		10,553		2,300
Long-term deposits		190		664
Financial liabilities:				
Held for trading, measured at fair value:				
Current portion of derivative instruments liability	$	8,852	$	10,031
Derivative instruments liability		7,450		22,132
Other long-term liabilities		3,100		–
Other financial liabilities, measured at amortized cost:				
Accounts payable and accrued liabilities	$	32,494	$	31,783
Interest payable on Subordinated Notes and convertible debentures		800		3,455
Dividends payable		5,242		1,918
Current portion of long-term and short-term debt		29,331		79,512
Long-term debt		297,652		364,155
Subordinated Notes		–		310,584
Convertible debentures		135,090		48,790

The fair value of financial assets and current financial liabilities which are measured at amortized cost approximates their carrying value because of the short-term nature of the instruments. The fair value of the convertible debentures at December 31, 2009 was determined using quoted market prices. The fair value of long-term debt was determined by discounting the remaining contractual cash flows using a rate at which the Company could issue debt with a similar maturity as of the balance sheet date. The fair value of these long-term liabilities is summarized in the following table:

		2009		2008
Long-term debt	$	344,255	$	467,300
Convertible debentures		141,251		46,675
Subordinated Notes		–		264,739

(b) Change in fair value of derivative instruments

The following table contains the components of income (expense) related to changes in the fair value of the Company's derivative financial instruments:

		2009		2008
Change in fair value of derivative instruments:				
Chambers power purchase agreement	$	(6,776)	$	74,608
Onondaga indexed swap and hedge		–		(10,844)
Project-level interest rate swaps		2,604		(5,038)
Project-level natural gas swaps		(7,182)		(3,378)
	$	(11,354)	$	55,348

(c) Derivative instruments

The components of derivative instruments assets and liabilities as of December 31, 2009 and 2008 are set forth in the following table:

		2009		2008
Current portion of derivative instruments asset:				
Chambers power purchase agreement	$	26,904	$	15,001
Foreign currency forward contracts		5,619		–
	$	32,523	$	15,001
Derivative instruments asset:				
Chambers power purchase agreement	$	90,579	$	109,258
Lake natural gas swaps		–		224
Foreign currency forward contracts		14,289		–
	$	104,868	$	109,482
Current portion of derivative instruments liability:				
Lake natural gas swaps	$	3,682	$	4,017
Auburndale natural gas swaps		399		4
Foreign currency forward contracts		–		744
Interest rate swaps		4,771		5,266
	$	8,852	$	10,031
Derivative instruments liability:				
Lake natural gas swaps	$	2,440	$	595
Auburndale natural gas swaps		1,200		–
Foreign currency forward contracts		–		12,998
Interest rate swaps		3,810		8,539
	$	7,450	$	22,132

CHAMBERS POWER PURCHASE AGREEMENT

The PPA at the proportionately consolidated Chambers Project meets the accounting definition of a derivative instrument. The PPA does not qualify for exclusion from CICA Handbook Section 3855, Financial Instruments – Recognition and Measurement, and has not been designated as a hedge. Accordingly, the PPA has been recorded at its fair value in the consolidated balance sheets and changes in the fair value are recognized in change in fair value of derivative instruments in the consolidated statements of income (loss), comprehensive income (loss) and deficit.

The fair value of the PPA is measured by comparing the net present value of the cash flows expected to be received under the terms of the PPA to the net present value of the cash flows that would be received if the same volumes were sold at projected market power prices over the term of the contract expiring in 2024. Accordingly, periodic changes to the fair value of the PPA reflect changes in forward market conditions and do not directly impact the amount of cash flows the Chambers Project will receive under the terms of the PPA. The most significant factor that impacts the calculated fair value of the PPA is the projected forward market prices of power, and such prices can vary significantly from period to period. As of December 31, 2009, a 10% change in the projected average forward power prices through the term of the PPA expiring in 2024 would change the fair value of the PPA by approximately $33 million.

FOREIGN CURRENCY FORWARD CONTRACTS

The Company uses forward foreign currency contracts to manage its exposure to changes in foreign exchange rates, as the Company earns its income in the United States but pays dividends to shareholders and interest on convertible debentures predominantly in Canadian dollars. Since its inception, the Company has established a hedging strategy for the purpose of reinforcing the long-term sustainability of cash distributions to holders of IPSs and common shares. The Company has executed this strategy by entering into forward contracts to purchase Canadian dollars at a fixed rate of Cdn$1.134 per U.S. dollar in amounts sufficient to make monthly distributions through December 2013 at the current annual dividend level of Cdn$1.094 per common share, as well as interest payments on the 2006 Debentures.

In addition, the Company has executed forward contracts to purchase Canadian dollars at fixed rates of exchange sufficient to make semi-annual interest payments on the 2006 Debentures. The contracts provide for the purchase of Cdn$1.9 million in April and in October of each year through 2011 at a rate of Cdn$1.1075 per U.S. dollar.

The foreign exchange forward contracts are recorded at estimated fair value based on quoted market prices and the estimation of the counterparty's credit risk, as required by EIC-173. Changes in the fair value of the foreign currency forward contracts are reflected in foreign exchange (gain) loss in the consolidated statements of income (loss), comprehensive income (loss) and deficit.

The following table contains the components of recorded foreign exchange (gain) loss for the periods indicated:

	2009	2008
Unrealized foreign exchange (gain) loss:		
Subordinated Notes and convertible debentures	**$ 55,508**	$ (85,212)
Forward contracts and other	**(31,138)**	48,564
	24,370	(36,648)
Realized foreign exchange gain on forward contract settlements	**(3,864)**	(8,044)
	$ 20,506	$ (44,692)

The following table illustrates the impact on the Company's financial instruments of a 10% hypothetical change in the value of the U.S. dollar compared to the Canadian dollar as of December 31, 2009:

Convertible debentures	$ 13,915
Foreign currency forward contracts	30,204
	$ 44,119

PASCO NATURAL GAS SWAPS

The Pasco Project's operating margin was exposed to changes in natural gas prices for the second half of 2008 as a result of the expiry of its favorably-priced natural gas supply contract on June 30, 2008 before the expiry of its PPA at the end of 2008. In the second quarter of 2008, the Company entered into a series of financial swaps that effectively fixed the price of natural gas at the Pasco Project during the second half of 2008.

These natural gas swaps are derivative financial instruments and the changes in the fair value of the natural gas swaps were recorded in change in fair value of derivative instruments in the consolidated statements of income (loss), comprehensive income (loss) and deficit. The natural gas swaps at Pasco expired in December 2008.

Beginning January 1, 2009, a new ten-year tolling agreement at the Pasco Project requires the PPA counterparty to provide natural gas needed to operate the plant and, as a result, the Pasco Project is no longer exposed to changes in market prices of natural gas.

LAKE AND AUBURNDALE NATURAL GAS SWAPS

The Lake Project's operating margin is exposed to changes in the market price of natural gas from the expiry of its natural gas supply contract on June 30, 2009 through the expiry 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 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 contract in mid-2012 until the termination of its PPA.

The Company has 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 through June 30, 2009 were recorded in other comprehensive income (loss) as they were designated as hedges of the risk associated with changes in market prices of natural gas. As of July 1, 2009, the Company has de-designated these natural gas swap hedges and the changes in their fair value are recorded in change in fair value of derivative instruments in the consolidated statements of income (loss), comprehensive income (loss) and deficit.

SUBORDINATED NOTES PREPAYMENT OPTION

The Company had the option to redeem the Subordinated Notes beginning on November 18, 2009 at an initial redemption price equal to 105% of the principal amount being redeemed. The Company determined that the redemption option is an embedded derivative that was recorded at fair value and periodic changes in fair value were recorded in other expenses in the consolidated statements of income (loss), comprehensive income (loss) and deficit.

On December 17, 2009, the Company exercised its Subordinated Note Call Option to redeem the remaining Cdn$40,677 principal value of Subordinated Notes at 105% of the principal amount (see Note 10). As of December 31, 2009, all Subordinated Notes have either been converted to new common shares or redeemed for cash and therefore the prepayment option no longer exists.

INTEREST RATE SWAPS

The Company's proportionately consolidated Chambers Project has executed interest rate swaps to economically fix a portion of the Project's exposure to changes in interest rates related to variable-rate project debt. These interest rate swaps are derivative financial instruments and are not designated as hedges for accounting purposes. Interest rate swaps are recorded at fair value as derivative financial instruments in the consolidated balance sheet and changes in fair value are recorded in change in fair value of derivative instruments in the consolidated statements of income (loss), comprehensive income (loss) and deficit. The primary factor that influences the fair value of interest rate swaps is changes in projected forward market interest rates.

The fair value of interest rate swaps reflects the cash flows due to or from the Company on the balance sheet date. Cash settlements related to interest rate swaps are recorded in interest expense in the consolidated statements of income (loss), comprehensive income (loss) and deficit.

The Company has executed interest rate swaps on the revolving credit facility and the non-recourse loan at its consolidated Auburndale Project to economically fix a portion of the respective exposure to changes in interest rates related to variable-rate debt. The interest rate swap agreements were designated as cash flow hedges of the forecasted interest payments under the project-level Auburndale debt and the credit facility when they were executed in November 2008. The interest rate swap termination date for the Auburndale project-level debt was November 30, 2009. On November 30, 2009, the Company terminated the interest rate swap on the revolving credit facility when the remaining outstanding balance on the credit facility was repaid.

In November 2009, the Company executed a new interest rate swap at Auburndale that terminates on November 30, 2013. The interest rate swaps are derivative financial instruments and are recorded in the consolidated balance sheet at fair value. Changes in the fair value of the interest rate swaps are recorded in other comprehensive income (loss) as they have been designated as a hedge of the risks associated with changes in market interest rates.

(d) Loans and receivables

Accounts receivable is primarily comprised of amounts due to the Company's consolidated and proportionately consolidated projects for sales of electricity under long-term contracts. As of December 31, 2009, there are no significant amounts of accounts receivable past due. The carrying value of loans and receivables approximates their fair value due to the short-term maturity of those financial instruments.

(e) Financial risk management

The Company has exposure to market risk, credit risk and liquidity risk from its 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 the Company's 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 the Company's cash flows as described in the following paragraphs.

The Company is 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. The Company manages this risk through the use of foreign currency forward contracts and, where possible, by establishing any new obligations in U.S. dollars instead of Canadian dollars. See Note 12(c) – Foreign Currency Forward Contracts for additional details about the Company's exposure to changes in currency exchange rates and the financial instruments that mitigate this risk through 2013.

Changes in interest rates do not have a significant impact on cash payments that are required on the Company's debt instruments as approximately 90% of the Company's debt, including non-recourse project-level debt and the Company's share of debt at unconsolidated Projects, bears interest at fixed rates. Some of the non-recourse debt obligations at the Company's proportionately consolidated Auburndale and Chambers projects bear 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. See Note 12(c) – Interest rate swaps for additional details. After considering the impact of interest rate swaps, the Company's share of variable-rate debt at consolidated and proportionately consolidated projects was $40.0 million at December 31, 2009. A hypothetical change in average interest rates of 100 basis points would change interest expense by approximately $0.4 million on an annual basis.

The Company's 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 designed to generally mitigate the impact on 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 to the Company if a customer or counterparty to a financial instrument fails to meet its contractual obligations. The Company's maximum exposure to credit risk is the carrying value of financial assets included in the consolidated balance sheet.

The Company's 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. The Company does not have a history of credit losses related to long-term contracts at the Projects and no significant amounts are currently past due. The Company's 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 the Company will not be able to meet its financial obligations as they become due. The Company believes 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.

13 • CAPITAL MANAGEMENT

The Company's overall objectives in capital management are to optimize the cost of capital related to existing assets and growth opportunities, as well as to maintain a prudent capital structure with risk characteristics that do not jeopardize realization of long-term value from the Company's assets. The capital structure of the Company consists of non-recourse Project-level debt, a credit facility, convertible debentures and common stock.

The Company currently pays a monthly dividend at an annual rate of Cdn$1.094 per common share.

The Company has historically raised debt capital at the operating or project level at interest rates lower than would be required on corporate-level debt. These financings are structured as non-recourse to the Company and an adverse impact from debt at any single project has no influence on debt at other projects; in virtually all cases the principal fully amortizes before the primary PPA expires.

In some cases the Company 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 determined by assessing the potential volatility of projected cash flows in order to maintain a low probability that a temporary project operating issue could cause the Company's 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 the Company's 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 banks participating equally. Acquisition bridge facilities have also historically been in place at this senior corporate level with the revolving credit facility lenders.

The capital structure is periodically reviewed by the Company's management and Board of Directors to determine whether changes are required to meet the objectives outlined above.

Other than the capital management decisions discussed in Note 12 and Note 13, there were no changes in the Company's approach to capital management during the period. Neither the Company nor any of its subsidiaries are subject to externally imposed capital requirements.

14 • INCOME TAXES

	2009	2008
Current income tax benefit	$ (7,956)	$ (12)
Future tax (benefit) expense	(38,595)	21,236
	$ (46,551)	$ 21,224

The following is a reconciliation of income taxes calculated at the Canadian enacted statutory rate of 30% and 33.5% at December 31, 2009 and 2008, respectively, to the provision for income taxes in the consolidated statements of income (loss), comprehensive income (loss) and deficit:

	2009	2008
Income tax computed at Canadian statutory rate	$ (21,326)	$ 48,562
Increase resulting from:		
Operating in countries with		
different income tax rates	(7,107)	9,423
	(28,433)	57,985
Valuation allowance	(2,298)	(39,840)
	(30,731)	18,145
Permanent differences	(2,760)	4,367
Canadian loss carryforwards	(13,204)	(2,786)
Branch profits tax	–	2,368
Prior year true-up	118	(1,078)
Other	26	208
	(15,820)	3,079
Income tax expense (benefit)	$ (46,551)	$ 21,224

The tax effect of temporary differences that give rise to significant portions of the future tax assets and future tax liabilities at December 31, 2009 and 2008 are presented below:

	2009	2008
Future tax assets:		
Intangible assets	$ 19,774	$ 18,888
Loss carryforwards	65,874	41,512
Accrued liabilities	16,212	16,182
Unrealized foreign exchange loss		
on Subordinated Notes	–	5,497
IPS issuance costs	1,374	540
Natural gas and interest rate hedges	573	2,136
Total future tax assets	103,807	84,755
Valuation allowance	(47,228)	(49,524)
	56,579	35,231
Future tax liabilities:		
Property, plant and equipment	(69,639)	(72,024)
Unrealized foreign exchange gain	(284)	(6,713)
Other	–	(1,377)
Total future tax liabilities	(69,923)	(80,114)
Net future tax liability	$ (13,344)	$ (44,883)

As of December 31, 2009, the Company had net operating loss carryforwards that are scheduled to expire in the following years:

2014	$ 6,093
2015	33,321
2026	35,848
2027	43,494
2028	41,806
2029	50,266
	$ 210,828

15 • COMMON STOCK AND NORMAL COURSE ISSUER BID

The issued and outstanding common shares are as follows:

	Number of shares (thousands)	Amount
Balance, December 31, 2007	61,470	$ 216,636
Issuance of common stock	30	127
Shares acquired in normal course issuer bid	(559)	(1,875)
Balance, December 31, 2008	60,941	$ 214,888
Issuance of common stock	59	151
Shares acquired in normal course issuer bid	(482)	(1,426)
IPSs converted to common shares	(114)	327,691
Balance, December 31, 2009	60,404	$ 541,304

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

On July 18, 2008, the Company approved a normal course issuer bid to purchase up to four million IPSs, representing approximately 8% of the Company's public float at that time. The Toronto Stock Exchange ("TSX") approved the issuer bid on July 23, 2008, and purchases under the bid commenced on July 25, 2008. As of December 31, 2009 and 2008, the Company acquired 481,600 and 558,620 IPSs at an average price of Cdn$8.42 and Cdn$8.78, respectively, under the terms of its existing normal course issuer bid. As of December 31, 2009, the Company had 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. The Company paid the market price at the time of acquisition for any IPSs purchased through the facilities of the TSX, and all IPSs acquired under the bid have been cancelled. The issuer bid expired on July 24, 2009.

The purchase price in excess of the average book value of the shares in the amount of $339 and $275 for the years ended December 31, 2009 and 2008, respectively, has been allocated to deficit.

16 • LONG-TERM INCENTIVE PLAN ("LTIP")

On March 30, 2009 and March 26, 2008, the Board of Directors approved grants of notional units to acquire a maximum of 267,408 and 142,717 common shares, respectively, under the terms of the LTIP. The weighted average fair value per notional unit granted was Cdn$7.27 and Cdn$10.18 for 2009 and 2008, respectively. The measurement date for the awards for accounting purposes occurred when participants were informed of the details of their awards in April 2009 and April 2008, respectively. As a result, compensation expense related to the LTIP was recorded in the amounts of $2,245 and $770 for the years ended December 31, 2009 and 2008, respectively.

In early 2010, the Board of Directors approved amendments to the LTIP. The amendments 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 the notional units granted prior to the amendments. However, the number of notional units granted will be based, in part, on the total shareholder return of the Company compared to a group of peer companies in Canada. In addition, vesting of notional units for officers of the Company will occur on a three-year cliff basis as opposed to ratable vesting over three years for grants made prior to the amendments.

17 • BASIC AND DILUTED EARNINGS (LOSS) PER SHARE

The following table sets forth the weighted average number of common shares outstanding and potentially dilutive shares utilized in per share calculations:

	2009	2008
Basic common shares outstanding	**60,632**	61,290
Dilutive potential common shares:		
Convertible debentures	**5,095**	4,839
LTIP notional units	**476**	221
Fully diluted common shares	**66,203**	66,350

Diluted earnings (loss) per share is computed including dilutive potential common shares as if they were outstanding common shares during the year. Dilutive potential common shares include common shares that would be issued if all of the convertible debentures were converted into common shares at January 1, 2008. Dilutive potential common shares also include the weighted average number of common shares, as of the date such notional units were granted, that would be issued if the unvested notional units outstanding under the Company's LTIP were vested and redeemed for common shares under the terms of the LTIP.

Because the Company reported a loss during the year ended December 31, 2009, the effect of including potentially dilutive shares in the calculation during 2009 is anti-dilutive.

18 • ACCUMULATED OTHER COMPREHENSIVE LOSS

The components of accumulated other comprehensive loss are as follows:

	2009	2008
Cumulative unrealized loss on natural gas hedges	**$ (538)**	$ (4,393)
Cumulative unrealized loss on interest rate swaps	**(894)**	(947)
Future tax benefit	**573**	2,136
	$ (859)	$ (3,204)

19 • RELATED PARTY TRANSACTIONS

Prior to December 31, 2009, the Company was managed by Atlantic Power Management, LLC (the "Manager"), which was owned by two private equity funds (the "ArcLight Funds") managed by ArcLight Capital Partners, LLC. On December 31, 2009, the Company terminated its management agreements with the Manager and has agreed to pay the ArcLight Funds an aggregate of $15 million, to be satisfied by a payment of $6 million 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. The Company recorded the remaining liability associated with the termination fee at its estimated fair value of $8.1 million and recorded $14.1 million of expense, which includes the $6.0 million payment made on the termination date, in management fees and administration expense within administrative and other expenses in the accompanying consolidated financial statements.

During the year ended December 31, 2009, in accordance with the management agreement between the Company and the Manager, the Company incurred management and incentive fees of $640 and $1,259, respectively. During the year ended December 31, 2008, the Company incurred management and incentive fees of $625 and $864, respectively.

On November 21, 2008, the Company acquired Auburndale from an entity owned by one of the ArcLight Funds and Caisse de dépôt et placement du Québec, which, at that time, owned approximately 19% of the Company's IPSs and Cdn$36.5 million of its outstanding Subordinated Notes. See Note 3(f).

20 • COMMITMENTS AND CONTINGENCIES

From time to time, the Company, its subsidiaries and the Projects are parties to disputes and litigation that arise in the normal course of business. The Company assesses its exposure to these matters and records estimated loss contingencies when a loss is likely and can be reasonably estimated. There are no matters pending as of December 31, 2009 which are expected to have a material impact on the Company's financial position or results of operations.

21 • DISCONTINUED OPERATIONS

In November 2009, the Company sold its interests in Stockton (Note 3(a)) and Mid-Georgia (Note 3(b)). The results of operations for Stockton and Mid-Georgia have been recorded as discontinued operations in the consolidated statements of income (loss), comprehensive income (loss) and deficit.

The components of income (loss) from discontinued operations are as follows:

Year ended December 31	2009	2008
Project revenue	**$ 20,790**	$ 32,648
Project expenses	**21,423**	32,365
Project other income (expenses)	**(2,708)**	(3,564)
Gain on sale of Mid-Georgia	**15,826**	–
Loss on sale of Stockton	**(2,046)**	–
Impairment charge at Stockton	**–**	(18,471)
Project income (loss) before taxes	**10,439**	(21,752)
Income tax expense (benefit)	**4,175**	(8,701)
Net income (loss) from discontinued operations	**$ 6,264**	$ (13,051)

22 • SEGMENTS

The Company has seven reportable segments: Path 15, Auburndale, Lake, Pasco, Chambers, Orlando and Other Project Assets. The Company reviews the financial performance of each Project individually. Accordingly, each Project is a separate operating segment. However, several of the Projects are not material, individually or in aggregate, and are therefore combined into a single reportable segment, "Other Project Assets."

22 • SEGMENTS (continued)

	Path 15	Auburndale	Lake	Pasco	Chambers	Orlando	Other Project Assets	Un-allocated corporate and other	Consolidated
Year ended December 31, 2009:									
Operating revenues	$ 31,000	$ 74,875	$ 62,285	$ 11,356	$ 50,745	$ 41,911	$ 16,109	$ –	$ 288,281
Income from long-term investments	–	–	–	–		–	2,519	–	2,519
Project expenses	3,309	39,654	36,907	8,057	37,150	33,053	10,595	–	168,725
Depreciation and amortization	8,510	19,780	10,098	2,986	6,811	5,641	2,021	–	55,847
Change in fair value of derivative instruments	–	(2,118)	(5,064)	–	(4,172)	–	–	–	(11,354)
Project interest expense	(12,911)	(2,832)	4	–	(7,674)	14	38	–	(23,361)
Other project income (expense)	1,228	–	–	25	(1,229)	(78)	13	–	(41)
Project income	7,498	10,491	10,220	338	(6,291)	3,153	6,063	–	31,472
Interest expense	–	–	–	–	–	–	–	55,665	55,665
Income tax expense (benefit)	–	–	–	–	–	–	–	(46,551)	(46,551)
Income (loss) from discontinued operations	–	–	–	–	–		6,264	–	6,264
Net income (loss)	7,498	10,491	10,220	338	(6,291)	3,153	12,327	(56,009)	(18,273)
Segment assets	219,586	130,053	118,925	42,479	316,412	41,701	32,533	135,863	1,037,552
Expenditures for additions to long-lived assets	–	321	1,278	355	902	632	86	61	3,635

	Path 15	Auburndale	Lake	Pasco	Chambers	Orlando	Other Project Assets	Un-allocated corporate and other	Consolidated
Year ended December 31, 2008:									
Operating revenues	$ 31,528	$ 10,003	$ 61,610	$ 58,897	$ 68,893	$ 34,372	$ 36,269	$ –	$ 301,572
Income from long-term investments	–	–	–	–		–	20,134	–	20,134
Project expenses	2,655	5,542	28,719	36,944	41,291	26,165	20,138	–	161,454
Depreciation and amortization	7,917	2,127	11,232	11,154	6,392	5,654	(913)	–	43,563
Change in fair value of derivative instruments	–	–	–	(3,378)	69,571	–	(10,845)	–	55,348
Project interest expense	(13,232)	(225)	33	(978)	(8,536)	16	(271)	–	(23,193)
Other project income (expense)	–	–	–	–	(580)	351	5,367	–	5,138
Project income	7,724	2,109	21,692	6,443	81,665	2,920	31,429	–	153,982
Interest expense	–	–	–	–	–	–	–	43,275	43,275
Income tax expense	–	–	–	–	–	–	–	21,224	21,224
Loss from discontinued operations	–	–	–	–	–	–	(13,051)	–	(13,051)
Net income (loss)	7,724	2,109	21,692	6,443	81,665	2,920	18,378	(30,243)	110,688
Segment assets	235,198	151,524	130,083	52,925	336,367	49,392	108,622	87,479	1,151,590
Expenditures for additions to long-lived assets	–	–	814	175	145	306	195	114	1,749

Progress Energy Florida, Atlantic City Electric Co. and the California Independent System Operator ("CAISO") provide for 55.5%, 13.9% and 10.8%, respectively, of total revenues for the year ended December 31, 2009 as compared to 51.4%, 19.4% and 10.5%, respectively, for the year ended December 31, 2008. Progress Energy Florida purchases electricity from Auburndale, Lake and Orlando, Atlantic City Electric Co. purchases from Chambers, and the CAISO makes payments to Path 15. In addition, during 2008 Progress Energy Florida purchased electricity from Pasco.

23 • SUBSEQUENT EVENTS

In March 2010, the Board of Directors approved amendments to the Long-Term Incentive Plan for employees of the Company. See Note 16 for further details.

In March 2010, the Company increased its ownership interest in Rollcast. See Note 3(d) for further details.

24 • COMPARATIVE FIGURES

Certain 2008 figures have been reclassified to conform to the financial statement presentation adopted in 2009.

Corporate and Shareholder Information

ATLANTIC POWER CORPORATION

Exchange: TSX

Common shares issued
and outstanding: 60,404,093
Ticker symbol: ATP

Cdn$60 million
6.50% Convertible Debentures
due October 31, 2014
Ticker symbol: ATP.DB

Cdn$86.25 million
6.25% Convertible Debentures
due March 15, 2017
Ticker symbol: ATP.DB.A

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Annual Meeting
Tuesday, June 29, 2010 at 10:00 AM EDT
The King Edward Hotel
Chelsea Room
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ATLANTIC POWER OFFICERS

Barry Welch
President and Chief Executive Officer

Patrick Welch
Chief Financial Officer and Corporate Secretary

Paul Rapisarda
Managing Director,
Asset Management & Acquisitions

ATLANTIC POWER CORPORATION DIRECTORS

Irving Gerstein
Chairman of the Board
Toronto, Ontario
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.

Ken Hartwick
Chairman of the Audit Committee
Toronto, Ontario
Mr. Hartwick is President and CEO and serves as a director for Just Energy, an integrated retailer of commodity products that is traded on the TSX.

John McNeil
Toronto, Ontario
Mr. McNeil is President of BDR North America Inc., an energy consulting firm based in Toronto, Ontario.

Barry Welch
Boston, Massachusetts
Mr. Welch is President and CEO of Atlantic Power Corporation.

Atlantic Power Corporation Directors
From left to right: John McNeil, Irving Gerstein, Barry Welch and Ken Hartwick

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