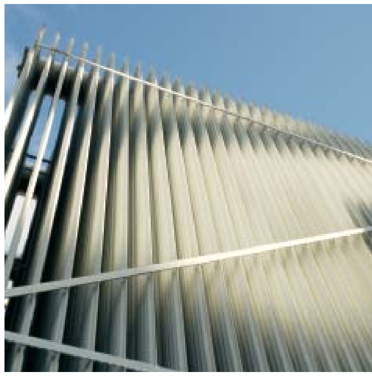
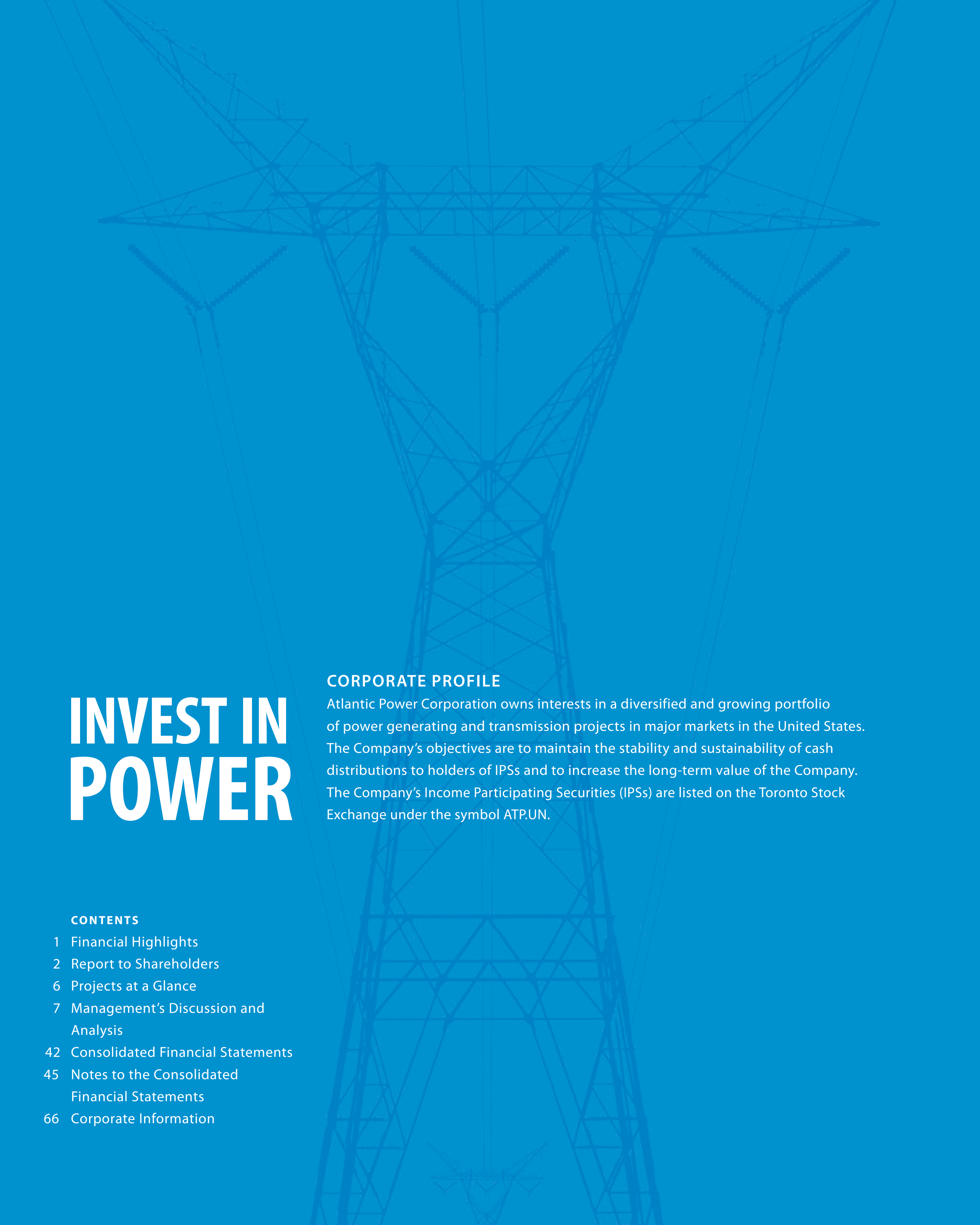
INVEST IN POWER

ATLANTIC POWER CORPORATION 2008 ANNUAL REPORT





AtlanticPower Corporation



INVEST IN POWER

CORPORATE PROFILE

Atlantic Power Corporation owns interests in a diversified and growing portfolio of power generating and transmission projects in major markets in the United States. The Company's objectives are to maintain the stability and sustainability of cash distributions to holders of IPSs and to increase the long-term value of the Company. The Company's Income Participating Securities (IPSs) are listed on the Toronto Stock Exchange under the symbol ATP.UN.

CONTENTS

2008

FINANCIAL HIGHLIGHTS

(US$000 except where noted and per IPS data)

YEARS ENDED DECEMBER 31	2008	2007
Project revenue	334,221	306,192
Project income	132,230	(113,395)
Total assets	1,151,590	1,081,847
Cash available for distribution (Cdn$000)	110,719	86,005
Cash available for distribution per basic IPS (Cdn$)	1.81	1.40
Total IPS distributions (Cdn$000)	65,143	65,181
Total distribution per basic IPS (Cdn$)	1.06	1.06

MEETING OUR GOALS

1 Sustain and grow cash flows:

> Cash available for distribution increased 29%, including one-time items

> Able to meet current level of cash distributions into 2015 without further acquisitions or organic growth

2 Make accretive acquisitions:

> Purchase of Auburndale Project in November 2008 was immediately accretive to distributable cash

> Pursuing development of several biomass power generation projects

3 Enhance financial flexibility:

> Extended currency hedge for cash distributions at favorable exchange rates for two more years through December 2013

> Continued to add natural gas hedges that enhance the stability of future operating margins

> Cost effectively financed Auburndale acquisition during challenging credit environment in late 2008

4 Generate strong returns for investors:

> 8% increase in cash dividend on common share portion of IPS

> While the share price was down in 2008, ATP's performance was better than its independent power peers, TSX Trust Index and TSX Composite Index

REPORT TO SHAREHOLDERS

In spite of the challenges facing the economy and capital markets in 2008, we successfully grew our base of power producing assets, increased cash available for distribution and raised our common share dividend for the third time in the past four years.

SOLID FINANCIAL RESULTS

We were pleased with our operating and financial results in 2008 as cash flow available for distribution rose to $103.7 million, an almost 30% increase from $80.1 million in the prior year. The increase was primarily due to higher Adjusted EBITDA from our projects as well as the positive impact of several non-recurring items. This solid performance resulted in a conservative payout ratio of 59% in 2008 compared to 77% in 2007.

As a result of an acquisition completed in November and our positive outlook on the future performance of our portfolio, we were pleased to increase the common share dividend portion of our Income Participating Security (IPS) distribution by 8%, or Cdn$0.034, bringing our total annual cash distribution to Cdn$1.094 per IPS. This was the third increase in cash distributions since our Initial Public Offering in November 2004, further proof that our strategies to enhance value are working.

GROWING AND STRENGTHENING OUR ASSET BASE

A key component of our initiatives to grow distributable cash is to make accretive acquisitions of power and related projects in targeted growth markets. Since our Initial Public Offering, we have added a total of three major projects to our portfolio and also acquired portions of other plants where we already had an ownership position. These acquisitions have increased our net megawatts owned by 28%, and all of these acquisitions have made strong contributions to our growth and performance.

In November 2008 we acquired 100% of the Auburndale facility, a 155-megawatt natural gas-fired


cogeneration facility in central Florida. We were able to complete and cost-effectively finance this transaction despite the unprecedented volatility in the financial markets and the resulting tight credit environment. The purchase price of approximately US$140 million was funded by cash on hand, $55 million in borrowings under our credit facility and $35 million of non-recourse acquisition debt.

The Auburndale acquisition was immediately accretive to cash flow and brings a number of additional benefits to Atlantic Power. The facility has a medium-term power purchase agreement through 2013 and a fuel supply agreement through mid-2012, which substantially hedges natural gas prices. Importantly, the plant has an excellent operating history since commencing operations in 1994 and we expect some synergies from our other operations in Florida.

ADDITIONAL DEVELOPMENTS

There were a number of other positive developments that bode well for strong performance going forward.

Taking advantage of lower natural gas forward curves during late 2008 and early 2009, we were able to enter into a series of financial swaps that hedge the price of significant portions of future natural gas purchases at our Lake Project through 2013 and at our new Auburndale facility. By capitalizing on these lower natural gas prices, we have enhanced the returns these investments will provide over the next few years.

Subsequent to year-end, our Path 15 transmission line in California reached a settlement on its 2008 through 2010 rate case that will allow the Project to make distributions to the Company consistent with management's expectations. Independently, the final resolution of the last pending landowner right-of-way litigation was resolved recently, which will result in the release of approximately $6 million to Path 15 in the second quarter of 2009 from a construction reserve account.

During the fourth quarter, we reviewed our investment in the Stockton Project in order to determine whether we would recover our investment in the project. This review was undertaken as a result of the current and long-term market conditions for coal-fired generating assets in California, including the dramatically lower price of natural gas, which drives the price received for the Project's electricity sales, and the significantly higher cost of Utah coal used by the Project.

Based on this review, we determined that the carrying value of the Stockton Project will not be recovered and recorded a pre-tax impairment charge of $18.5 million at year-end. This represents the entire carrying value of the project's property, plant and equipment. Subsequent to year-end, Stockton's Power Purchase Agreement (PPA) was extended through March 2010 and we are considering a number of options to achieve additional recovery of our investment in the Project. Over the past three years Stockton has represented on average only about 2% of total annual Project distribution.

RENEWABLE ENERGY INITIATIVES

As had been anticipated since our Initial Public Offering, our Onondaga Project was formally taken offline on April 30, 2008. Since the shutdown, we have successfully sold the project's gas turbines, spare parts and other

equipment for total proceeds of approximately $7.5 million. We are also making solid progress working with an experienced partner to re-develop and convert the site into a 35 to 40 megawatt biomass facility, providing renewable energy for the equivalent of up to 40,000 local homes. This state-of-the-art facility would be the cleanest biomass plant in New York State and would create approximately 24 jobs at the plant as well as 150 fuel-related jobs. The design, development and permitting process is progressing well.

In addition to the potential Onondaga conversion, in April we finalized an investment in a biomass development company with a current pipeline of five 50-megawatt biomass power plants in various stages of development. Two of these projects have 20-year PPAs signed, which include fuel price pass-through mechanisms. The development company's management team has more than 30 years of experience in project development, management and financing, with an emphasis on solid fuels. This opportunity will give us the option to invest equity in their five renewable energy projects. Renewable energy incentives included in the American Recovery and Reinvestment Act of 2009 significantly enhance the potential economic value of this investment and the Onondaga conversion.

FINANCIAL MARKETS AND DISTRIBUTION SUSTAINABILITY

Despite the challenging credit markets experienced through 2008 and continuing into 2009, we remain confident in our ability to make additional investments in our projects as well as potential new acquisitions. While lending spreads for project-level debt are wider than they have been historically, underlying Treasury and LIBOR rates have remained relatively low, and as a result all-in rates are reasonable. We are regularly in contact with our lenders and all have significant ongoing interest in financing our projects.

On the growth front, we continue to evaluate a solid pipeline of opportunities across North America, including proprietary deal flow from our industry network, and we have a continuing ability to finance potential acquisitions without accessing the public equity markets.

Most important for our investors, based on our projections of distributable cash flow from existing projects, utilizing reputable third-party commodity cost forecasts

and including our cash on hand, we can continue the current level of monthly cash distributions well into 2015 without any additional acquisitions or organic growth. This guidance includes the fact that we expect distributions from projects in 2009 will decline to between $90 million and $95 million due to expiring contracts at specific projects, a drop in Chambers' contribution due primarily to a planned full plant shutdown for maintenance, and the absence of certain one-time items that positively impacted cash flows in 2008.

To further mitigate currency risk, in the fourth quarter of 2008, after a significant strengthening of the U.S. dollar, we extended our forward purchases of Canadian dollars at favorable rates for two additional years through 2013.

We are also utilizing our excess cash to enhance value by acquiring IPSs in the open market. As of December 31, 2008 we had acquired and canceled 558,620 IPSs at an average price of Cdn$8.78 under our approved issuer bid. We continued to acquire IPSs in 2009 as we believe they are an attractive investment and a prudent use of the Company's cash.

A POSITIVE FUTURE

Looking ahead, we remain confident in our ability to provide investors with stable, sustainable and growing cash distributions over the long term.

We are evaluating additional acquisition opportunities within the North American power industry that meet our investment guidelines and will increase distributable cash flow. Capitalizing on our strong relationships with our investors, existing project partners and our broader industry network, we have excellent access to these growth opportunities. Our investment in the biomass development company is a perfect example of positioning ourselves for superior investment opportunities in the renewable energy marketplace.

We continue to work closely with our project managers to enhance the operating and financial performance of our existing facilities. Initiatives such as equipment upgrades and the optimization of our power purchase agreements, fuel supply contracts and other commercial arrangements serve to enhance returns at these projects. Our initiative to convert the Onondaga plant to a biomass project is just one example of this creative strategy in action.

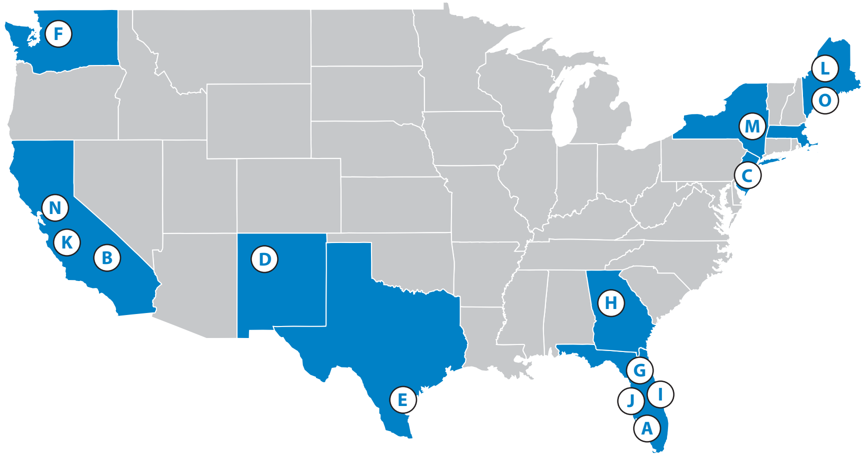
Finally, we will continue to look for opportunities to consolidate and increase our ownership in projects where we have partial interests. We know these projects, we are comfortable with their operations and we can accurately assess their future potential and risk profile.

In closing, we are pleased with the continued success we have had in executing our strategies to grow distributable cash and increase the value of the Company. I would like to thank our employees for their hard work in making this possible and our shareholders for their continued support.

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. growth markets from coast to coast, continue to deliver strong operating performance and stable, sustainable and growing cash flow for our investors.



	PROJECT NAME	LOCATION	FUEL TYPE	TOTAL MW	OWNERSHIP INTEREST	NET MW
A	Auburndale	Auburndale FL	Natural Gas	155	100.00%	155
B	Badger Creek	Bakersfield CA	Natural Gas	46	50.00%	23
C	Chambers	Carney's Point NJ	Coal	262	40.00%	105
D	Delta-Person	Albuquerque NM	Natural Gas	132	40.00%	53
E	Gregory	Corpus Christi TX	Natural Gas	400	17.10%	68
F	Koma Kulshan	Whatcom County WA	Hydro	13	49.80%	6
G	Lake	Umatilla FL	Natural Gas	121	100.00%	121
H	Mid-Georgia	Kathleen GA	Natural Gas	308	50.00%	154
I	Orlando	Orlando FL	Natural Gas	129	50.00%	65
J	Pasco	Tampa FL	Natural Gas	121	100.00%	121
K	Path 15	California	Transmission	N/A	100.00%	N/A
L	Rumford	Rumford ME	Coal/Biomass	85	23.50%	20
M	Selkirk	Bethlehem NY	Natural Gas	345	18.50%	64
N	Stockton	Stockton CA	Coal	55	50.00%	27
O	Topsham	Topsham ME	Hydro/Biomass	14	50.00%	7

Additional details in MD&A on page 23.

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 annual consolidated financial statements of Atlantic Power Corporation ("Atlantic Power" or the "Company") for the year ended December 31, 2008. All dollar amounts in this MD&A are in thousands of U.S. dollars, unless otherwise stated. The annual financial statements have been prepared in accordance with Canadian generally accepted accounting principles ("GAAP").

Forward-Looking Statements

Certain statements in this MD&A may constitute "forward-looking statements", which reflect the expectations of Atlantic Power Management, LLC (the "Manager") regarding future growth, results of operations, performance and business prospects and opportunities of the Company and the Projects (as defined below). Examples of such statements include: the expectation that the Company's cash on hand and projected future cash flows will be adequate to meet the current level of cash distributions to IPS holders into 2015; the amount of distributions expected to be received from the Projects for the full year 2009; the Company's current forecast of expected annual cash distributions from the Lake and Auburndale Projects through 2012; and the expected decrease in distributions from Chambers in 2009. Such forward-looking statements reflect current expectations regarding future events and operating performance and speak 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 will not necessarily be 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 had to the factors discussed under "Risk Factors" in the Company's Annual Information Form dated March 30, 2009. 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 and to give readers a better understanding of the Company's ability to pay its current level of distributions into the future. Readers are cautioned that such information may not be appropriate for other purposes.

Information contained in this MD&A is based on information available to management as of March 30, 2009.

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.atlanticpowercorporation.com.

Overview

As of March 30, 2009, the Company has 60,938,731 income participating securities ("IPSs"), and Cdn$60 million principal amount of 6.25% convertible secured debentures due October 31, 2011 (the "Debentures") outstanding. Atlantic Power Holdings, LLC ("Holdings") was formed in 2004 to acquire indirect interests in a diversified portfolio of power generating facilities located primarily in major markets in the United States from ArcLight Energy Partners Funds I, L.P. ("Fund I") and ArcLight Energy Partners Funds II, L.P. ("Fund II", and, together with Fund I, the "ArcLight Funds") and Caithness Energy, LLC ("Caithness") (together with the ArcLight Funds, the "Former Investors"). As of February 2007, Holdings became a wholly-owned subsidiary of the Company.

Each IPS is comprised of: (1) one common share of the Company ("Common Share"); and (2) Cdn$5.767 aggregate principal amount of 11.0% subordinated notes of the Company ("Subordinated Notes"). IPS investors receive a monthly distribution comprised of a dividend payment on the Common Share and an interest payment on the Subordinated Notes. The current annual total distribution is Cdn$1.09 per IPS.

The Debentures were issued on October 11, 2006 and bear interest at an annual rate of 6.25%, payable semi-annually in arrears on April 30 and October 31 of each year commencing on April 30, 2007. The Debentures are convertible at any time, at the option of the holder, into 80.6452 IPSs per Cdn$1,000 principal amount of Debentures, representing a conversion price of Cdn$12.40 per IPS.

As of December 31, 2008, the Company owned interests in 14 power generating facilities in the United States and a transmission line in central California (collectively, the "Projects" and individually, a "Project"). The generating Projects have a combined total power generating capacity of approximately 2,186 megawatts ("MW"). The Company's net interests in the Projects represented approximately 988 MW of power generating capacity as of December 31, 2008. Most of the generating Projects sell their power under 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 and is collected by the California Independent System Operator ("CAISO") from utilities in California without variations resulting from changes in power prices or line usage and with virtually no technical or operating risks.

The Company's objectives are to maintain the stability and sustainability of cash distributions to holders of IPSs and to increase the long-term value of the Company. To achieve these objectives, Company management, working directly with Project managers, 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 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 Manager'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 significant exposure to commodity price risk. More than 90% of the Company's existing debt 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 and a large portion of the Company's cash obligations, primarily distributions on IPSs 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 distributions and other Canadian dollar obligations at fixed rates through 2013.

Recent Developments

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 13.5% return on equity 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 terms of the settlement will allow Path 15 to make distributions to the Company that are consistent with management's expectations in 2009 and 2010. The Company expects the FERC to approve the settlement in the next two to three months. Once it is approved, Path 15 will be making a refund of approximately $1.3 million, comprising the amount collected above the settlement rates since the initial order in February 2008. Independently, the final resolution of pending landowner litigation over right-of-way issues was resolved recently, which will result in approximately $6 million being released in the second quarter to Path 15 from a construction reserve account.

In the fourth quarter of 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 will not be recovered and recorded a pre-tax long-lived asset impairment of $18,471, which represents the entire value of the Project's property, plant and equipment at December 31, 2008. The Company has extended the PPA through March 2010 and is also considering a variety of options to recover some of its remaining investment in the Stockton Project. The Stockton Project has historically contributed less than 4% of the Company's distributions received from Projects.

On November 21, 2008, the Company acquired 100% of Auburndale Power Partners, Limited Partnership ("Auburndale"), which owns and operates a 155 MW natural gas-fired combined cycle cogeneration facility located in Polk County, Florida. The purchase price was approximately $140 million, including acquisition cost and was funded by cash on hand, a borrowing under the Company's credit facility and $35 million of non-recourse acquisition debt.

Auburndale is the last of the Projects in which the Company was granted a right of first offer by ArcLight Energy Partners Fund I, L.P. ("ArcLight Fund I") at the time of the Company's initial public offering. ArcLight Fund I was the majority owner of a portion of the project through Pomifer Funding, LLC ("Pomifer"), an entity in which Caisse de dépôt et placement du Québec ("CDP") is a minority owner. ArcLight Fund I is one of the owners of Atlantic Power Management, LLC, the Manager of the Company, and CDP owns approximately 19% of the Company's IPSs and Cdn$36.5 million of its outstanding subordinated notes. An independent financial advisor provided a fairness opinion to the independent directors of the Company, given that two of the sellers were related parties. The remaining portion of Auburndale was owned by Calpine Corporation ("Calpine").

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. 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, 2008, the Company had acquired 558,620 IPSs at an average price of Cdn$8.78 under the terms of the issuer bid. The issuer bid will terminate on July 24, 2009 or such earlier date that the Company has acquired the maximum number of IPSs under the issuer bid. Atlantic Power will pay the market price at the time of acquisition for any IPSs purchased and all IPSs acquired under the bid will be canceled.

As previously disclosed since the Company's IPO, the Onondaga Project was formally taken offline on April 30, 2008, although payments continued under the Project's swap and indexed hedge agreements through June 2008. This plant was taken out of service as a result of the relative efficiency of its equipment and the regional electricity market. This combination of factors is not typical at the Company's other Projects. The Project sold its gas turbines, spare parts and other equipment. Proceeds from these equipment sales in the amount of $7.5 million were received during the year ended December 31, 2008. The Company is continuing its efforts with an experienced developer to redevelop the site into a 35 to 40 MW biomass plant and has contributed certain remaining assets of the Onondaga Project to the new joint venture.

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 from the Company's financial statements to Cash Flow Available for Distribution is set out in the "Cash Flow Available for Distribution" section of this MD&A. Investors are cautioned that the Company may calculate this measure in a manner that is different from other companies.

Earnings before 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)	**2008**	2007	2006	**2008**	2007	2006
Project income						
Project revenue	**88,219**	76,030	69,506	**334,221**	306,192	261,091
Project expenses	**62,678**	51,219	47,454	**237,383**	204,805	181,753
Project other income (expense)	**56,073**	(120,241)	(7,447)	**35,392**	(214,782)	(22,091)
Total project income (loss)	**81,614**	(95,430)	14,605	**132,230**	(113,395)	57,247
Administrative and other expenses						
Management fees and administration	**2,489**	2,574	1,894	**10,012**	8,185	6,367
Interest, net	**9,589**	10,607	9,858	**43,275**	44,282	31,589
Distribution, non-controlling interest	**–**	–	2,029	**–**	–	15,107
Loss from change in non-controlling interest liability	**–**	–	1,647	**–**	–	3,691
Foreign exchange loss (gain)	**(27,392)**	2,030	(5,297)	**(44,719)**	30,142	1,295
Other expenses	**(42)**	399	287	**451**	975	1,029
Total administrative and other expenses	**(15,356)**	15,610	10,418	**9,019**	83,584	59,078
Income (loss) before income taxes	**96,970**	(111,040)	4,187	**123,211**	(196,979)	(1,831)
Income tax expense (benefit)	**18,046**	(36,797)	1,253	**12,523**	(47,774)	577
Net income (loss)	**78,924**	(74,243)	2,934	**110,688**	(149,205)	(2,408)
Basic earnings (loss) per share, US$	**$ 1.30**	$ (1.21)	$ (0.06)	**$ 1.81**	$ (2.43)	$ (0.05)
Basic earnings (loss) per share, Cdn$	**$ 1.58**	$ (1.19)	$ (0.06)	**$ 2.20**	$ (2.61)	$ (0.06)
Diluted earnings (loss) per share, US$	**$ 1.20**	$ (1.21)	$ (0.05)	**$ 1.67**	$ (2.43)	$ (0.05)
Diluted earnings (loss) per share, Cdn$	**$ 1.45**	$ (1.19)	$ (0.06)	**$ 2.03**	$ (2.61)	$ (0.06)
Total assets at December 31	**1,151,590**	1,081,847	1,232,696	**1,151,590**	1,081,847	1,232,696
Total long-term liabilities at December 31	**826,011**	881,403	847,052	**826,011**	881,403	847,052
Cash flows from operating activities	**42,311**	47,184	23,883	**107,243**	85,901	57,521
Cash distributions declared per IPS, Cdn$	**$ 0.27**	$ 0.27	$ 0.27	**$ 1.06**	$ 1.06	$ 1.04

Results of Operations for the Three and Twelve-Month Periods Ended December 31, 2008

OVERVIEW

Project income is the primary GAAP measure of the Company's operating results and is discussed in "Project Operations Performance – Three and Twelve-month Periods Ended December 31, 2008" below. In addition, an analysis of non-project expenses impacting the results of the Company is set out in "Administrative and Other Expenses" below.

Significant non-cash items, which are subject to potentially significant fluctuations, include: (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); (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 (3) currency forward contracts; and the related future income tax expense (benefit) associated with these non-cash items.

Cash flow available for distribution was $37,177 and $103,728 for the three and twelve months ended December 31, 2008, respectively, compared to $42,305 and $80,116 for the respective comparable periods in 2007. See "Cash Flow Available for Distribution" in this MD&A for additional information.

Income before income taxes for the three and twelve months ended December 31, 2008 was $96,970 and $123,211 respectively, compared to a loss before income taxes of $111,040 and $196,979 for the respective comparable periods in 2007. The change reflects project income of $81,614 and $132,230 during the three and twelvemonths ended December 31, 2008, respectively, compared to a project loss of $95,430 and $113,395 for the respective comparable periods in 2007. See "Project Income" in this MD&A for additional information. The following table contains significant non-cash and unusual items that impacted project income and income before taxes in each period:

	Three months ended December 31,		Twelve months ended December 31,	
	2008	2007	**2008**	2007
Project income (loss), as reported	**$ 81,614**	$ (95,430)	**$ 132,230**	$ (113,395)
Non-cash and unusual items:				
Change in fair value of derivative instruments	**(77,491)**	38,730	**(55,061)**	128,377
Chambers goodwill impairment	**–**	71,726	**–**	71,726
Stockton long-lived asset impairment	**18,471**	–	**18,471**	–
Gain on settlement of Onondaga gas transportation contract	**–**	–	**–**	(10,040)
Loss on sale of replaced gas turbines at Lake	**–**	8,554	**–**	8,554
Project income (loss), excluding non-cash and unusual items noted above	**$ 22,594**	$ 23,580	**$ 95,640**	$ 85,222
Income, (loss) before income taxes as reported	**$ 96,970**	$ (111,040)	**$ 123,211**	$ (196,979)
Non-cash and unusual items:				
Non-cash and unusual items impacting project income from above	**(59,020)**	119,010	**(36,590)**	198,617
Unrealized foreign exchange loss (gain)	**(27,702)**	5,802	**(36,675)**	37,716
Income (loss) before income taxes excluding non-cash and unusual items	**$ 10,248**	$ 13,772	**$ 49,946**	$ 39,354

PROJECT INCOME

Project revenue increased 16% to $88,219 and 9% to $334,221 during the three and twelve months ended December 31, 2008, respectively. The change in the fourth quarter is attributable to the following factors:

- Acquisition of the Auburndale Project in November 2008.
- Increased ownership in the Pasco Project that was acquired in December 2007.
- Higher revenues at Pasco, Lake and Orlando as a result of higher power prices.
- Receipt of a partial settlement of business interruption insurance claims at Orlando related to the unplanned outage earlier in 2008.
- Higher revenues at Lake as a result of higher volumes of electricity sold when compared to the fourth quarter of 2007 when the plant was out of service for its gas turbine upgrade.
- 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, as previously disclosed.

For the year ended December 31, 2008, the change in Project revenue is attributable to the factors described above for the fourth quarter and the following other factors from the first nine months of the year:

- Higher revenues at Pasco, Lake, Chambers and Badger Creek as a result of higher power prices.
- Lower revenue at Mid-Georgia due to lower electricity sales volumes resulting from cooler weather in the third quarter of 2008 compared to the third quarter of 2007.

Project expenses increased by $11,459 or 22% during the three months ended December 31, 2008, as compared to the comparable quarter, primarily as a result of the following factors:

- Acquisition of Auburndale Project in November 2008.
- Increased ownership in the Pasco project that was acquired in December 2007.
- Higher fuel costs at Pasco as a result of the Project's consumption of natural gas at market prices following the expiration of its fuel supply agreement on June 30, 2008. Beginning January 1, 2009, a new 10-year PPA at the Pasco Project requires the PPA counterparty to provide natural gas required to operate the plant and, as a result, the Pasco Project will no longer be exposed to changes in market prices of natural gas.

Project expenses for the year ended December 31, 2008 increased by $32,578 or 16%, as a result of the fourth quarter factors described above and costs at Onondaga in connection with the shutdown of the plant in April 2008.

Project other income (expense) primarily includes the following items with details provided below:

	Three months ended December 31,		Twelve months ended December 31,	
	2008	2007	**2008**	2007
Change in fair value of derivative instruments	**$ 77,491**	$ (38,730)	**$ 55,061**	$ (128,377)
Impairment of Stockton Project	**(18,471)**	–	**(18,471)**	–
Impairment of Chambers goodwill	**–**	(71,726)	**–**	(71,726)
Gain on settlement of Onondaga gas transportation contract	**–**	–	**–**	10,040
Loss on sale of replaced gas turbines at Lake	**–**	(8,554)	**–**	(8,554)

- The non-cash impact of the change in fair value of derivative instruments is primarily related to the accounting treatment of the PPA at the Chambers Project as a derivative instrument. The accounting treatment of this PPA does not directly impact 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 the Company's derivative instruments and other financial instruments.
- In the fourth quarter of 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 value of the Stockton Project

will not be recovered and recorded a pre-tax long-lived asset impairment of $18,471, which represents the entire value of the Project's property, plant and equipment at December 31, 2008. The Company has extended the PPA through March 2010 and is also considering a variety of options to recover some of its remaining investment in the Stockton Project.

- In the fourth quarter of 2007, the goodwill at the Chambers Project was written off as a result of the significant increase in the book value of the reporting unit due to the Project's PPA being recorded as a financial instrument at fair value.
- In the second quarter of 2007, a gain of $10,040 was recorded on the settlement of a gas transportation contract liability at the Onondaga Project.
- In the fourth quarter of 2007, a loss of $8,554 was recorded on the sale of the gas turbines that were replaced at the Lake Project as a result of the installation of new and more efficient turbines.

Income from cost and equity method investments decreased in the fourth quarter of 2008 compared to the prior year period because of a delay in timing of distributions received from the Selkirk Project as a result of restrictions under the terms of the Project's non-recourse debt. The Project passed the test again beginning in December and management currently believes that the remaining restricted cash will become available for distribution in 2009.

For the twelve-month period ended December 31, 2008, income from cost and equity method investments increased significantly due to the receipt of an $8.2 million distribution from the Gregory Project resulting from the release of debt service reserves, as well as the absence of an impairment in the Jamaica Project that was recorded in the second quarter of 2007 related to the sale of that investment.

ADMINISTRATIVE AND OTHER EXPENSES

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 receives compensation in the form of an annual base fee that is indexed to inflation and an incentive fee that is equal to 25% of the cash distributions to IPS holders in excess of Cdn$1.00 per year per IPS. The Company also reimburses the Manager for reasonable costs incurred to manage the Company. The increase in management fees and administration for the twelve months ended December 31, 2008 from the comparative prior year period is primarily attributable to costs associated with pursuing acquisitions that were not completed in the 2008 periods, as well as personnel additions and expense recognized related to awards under the Company's long-term incentive plan that were granted in March 2008 and March 2007.

Interest expense primarily relates to required interest payments to holders of the Subordinated Notes and the Debentures. In addition, there were amounts outstanding on the Company's revolving credit facility during the first half of 2007 related to the temporary financing of the acquisition of the Path 15 Project, as well as amounts outstanding as of December 31, 2008 on the Company's revolving credit facility due to the acquisition of Auburndale.

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 increased by approximately 12.6% during the three months ended December 31, 2008 and increased by approximately 18.6% during the year ended December 31, 2008. In the prior year comparative periods, the rate decreased by 0.4% and 17%, 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 gains recognized during the three and twelve months ended December 31, 2008 compared to the foreign exchange losses in the prior year 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.

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 investments 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 at 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 Projects. 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 at the Projects is only secured by assets at the Projects and is non-recourse to the Company.

PROJECT OPERATIONS PERFORMANCE – THREE AND TWELVE MONTHS ENDED DECEMBER 31, 2008

Aggregate Adjusted EBITDA for the Projects, including earnings from projects accounted for under the equity method, increased by $2,899 or 7% during the fourth quarter of 2008 compared to the fourth quarter of 2007 and included the following factors:

- Acquisition of the Auburndale Project in November 2008.
- Receipt of a partial settlement of business interruption and property insurance claims at Orlando related to the unplanned outage earlier in 2008.
- Receipt of a distribution in the fourth quarter of 2008 from the Gregory Project, compared to no distribution from Gregory in the prior year fourth quarter.
- Increased Adjusted EBITDA at Lake due to higher power prices and higher plant efficiency as a result of the turbine upgrades performed in the fourth quarter of 2007.
- 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, as previously disclosed.
- A delay in the timing of a portion of the planned distribution from the Selkirk Project in the fourth quarter of 2008 as a result of restrictions under the terms of the Project's non-recourse debt. The Project passed the test again beginning in December 2008 and management currently believes that the remaining restricted cash will become available for distribution in 2009.

For the year ended December 31, 2008, Adjusted Project EBITDA increased by $1,849 or 1% during the year ended December 31, 2008 compared to the comparable period in 2007. In addition to the factors described above for the fourth quarter, the year-to-date period included the following factors:

- Receipt of an $8.2 million distribution from the Gregory Project in the first quarter of 2008 resulting from releases of debt services reserves at that Project.
- Higher Adjusted EBITDA at Pasco due to the acquisition of the additional interest in the Project in December 2007 and higher power prices, offset by higher fuel costs as a result of market price purchases following the expiration of its fuel supply agreement on June 30, 2008. Beginning January 1, 2009, a new 10-year PPA at the Pasco Project requires the PPA

counterparty to provide natural gas required to operate the plant and, as a result, the Pasco Project will no longer be exposed to changes in market prices of natural gas.

- Absence of Adjusted EBITDA from Jamaica due to the sale of the Project in 2007.

Aggregate power generation for assets in operation at December 31, 2008 was 1.7% lower during the twelve months ended December 31, 2008, compared to the same period in 2007. Plant availability declined 2.9% over the same period. Generation in the twelve-month period was unfavorably impacted by reductions in generation at Orlando, due to the generator forced outage; and at Pasco, as a result of a longer scheduled outage in 2008, versus the same period in 2007. The reduction in generation was offset by increased generation at Lake, due to the upgrade of combustion turbines in late 2007; Selkirk, resulting from increased dispatch of the plant; and the acquisition of Auburndale in late 2008.

The Project portfolio achieved a weighted average availability of 91.1% for the twelve months ending December 31, 2008, versus 94.0% in the same period last year. The lower availability was driven by the forced outage at Orlando and a longer scheduled outage at Mid-Georgia versus the previous year. Each of the Projects with reduced availability was nevertheless able to achieve 100% 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

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 Holdings during the year can also vary.

The Company's cash flow from operating activities decreased by $4,873 to $42,311 for the three-month period ended December 31, 2008 compared to the same period in the prior year. The decrease was primarily attributable to a larger income tax refund in the 2007 fourth quarter, partially offset by the release of debt service reserves at Pasco in the fourth quarter of 2008 as a result of the final payment of the Project's debt. In addition, the working capital change in the fourth quarter of 2007 was positively impacted by the receipt of a full month of third quarter revenues at the Lake and Orlando Projects on the first day of the fourth quarter and this timing difference did not occur in the fourth quarter of 2008.

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 principal payments are made on the related debt. As a result, the timing of principal payments on Project-level debt causes significant fluctuations in restricted cash balances, which typically benefit operating cash flow in the second and fourth quarters of the year and decrease operating cash flow in the first and third quarters of the year.

For the year ended December 31, 2008, cash flow from operating activities increased by $21,342, or 25%, to $107,243 when compared to the 2007 period. The increase for the twelve-month period includes the impact of higher Project Adjusted EBITDA and positive working capital changes in the full year 2008 compared to 2007. Significant items contributing to the positive impact of working capital on operating cash flow in 2008 include the release of Pasco debt service reserves throughout the year in a total amount of approximately $13 million, as well as the permanent release of working capital at Onondaga that was required to operate the facility.

Cash Flow Available for Distribution

Holders of IPSs receive cash distributions in the form of interest payments on Subordinated Notes and dividends on Common Shares. Cash flow available for distribution in the three months and twelve months ended December 31, 2008 increased (decreased) by $(5,128) and $23,612, respectively, when compared the same periods in 2007 due to primarily the changes in cash flow from operating activities described above.

The Company periodically evaluates its level of dividends with its Board of Directors by analyzing long-term cash flow projections, as well as the accretion to cash flow provided by acquisitions. On November 21, 2008, in connection with the closing of the Auburndale acquisition, the Company announced an increase of Cdn$.034 per share in the annual common share dividend. The increase was applicable to holders of record beginning on December 31, 2008 and brings the total annual distribution, including the interest payments on the Subordinated Notes component of the IPS, to Cdn$1.094 per IPS.

The table below presents the Company's calculation of Cash Available for Distribution for the three and twelve months ended December 31, 2008 and 2007.

(In thousands of U.S. dollars, except as otherwise stated)	Three months ended December 31,		Twelve months ended December 31,	
(unaudited)	**2008**	2007[1]	**2008**	2007[1]
Cash flows from operating activities	**42,311**	47,184	**107,243**	85,901
Project-level debt repayments	**(13,584)**	(13,156)	**(38,277)**	(37,581)
Interest on IPS portion of Subordinated Notes	**7,923**	9,968	**36,560**	36,726
Purchase of property, plant and equipment	**527**	(1,691)	**(1,798)**	(4,930)
Cash Flow Available for Distribution[2], US$	**37,177**	42,305	**103,728**	80,116
Interest on IPS Subordinated Notes	**7,923**	9,968	**36,560**	36,726
Dividends on IPS Common Shares	**5,463**	6,693	**24,693**	24,662
Total IPS distributions, US$	**13,386**	16,661	**61,253**	61,388
Payout ratio	**36%**	39%	**59%**	77%
Cash Flow Available for Distribution per IPS, US$				
Basic	**$ 0.61**	$ 0.69	**$ 1.69**	$ 1.30
Diluted	**$ 0.59**	$ 0.66	**$ 1.62**	$ 1.26
Total distribution declared per IPS, US$	**$ 0.22**	$ 0.27	**$ 1.00**	$ 1.00
Cash Flow Available for Distribution, Cdn$	**45,065**	41,542	**110,719**	86,005
Total IPS distributions, Cdn$	**16,328**	16,295	**65,143**	65,181
Cash Flow Available for Distribution per IPS, Cdn$				
Basic	**$ 0.74**	$ 0.68	**$ 1.81**	$ 1.40
Diluted	**$ 0.71**	$ 0.65	**$ 1.73**	$ 1.35
Total distribution declared per IPS, Cdn$	**$ 0.27**	$ 0.27	**$ 1.06**	$ 1.06

1 Amounts previously reported in 2007 have been revised to conform to the calculation of Cash Available for Distribution adopted in 2008, which does not include any adjustment for income taxes recoverable. Through the end of 2007, the Company was required to pay tax instalments based on estimates of taxable income without the benefit of the interest deduction related to the Subordinated Notes and Debentures. This requirement resulted in the payment of significant tax instalments to the IRS, followed by a refund of most of the instalment payments when the actual tax returns were filed in subsequent periods with the full benefit of the interest deductions on the Subordinated Notes and Debentures. As of January 1, 2008, the Company is permitted to calculate tax instalment payments with the full benefit of these interest payments factored into estimated taxable income. As a result, management expects significant fluctuations in working capital related to tax instalments and subsequent refunds to decrease and the adjustment to Cash Flow Available for Distribution is no longer needed.

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

	Three months ended December 31,	Years ended December 31,		
	2008	**2008**	2007	2006
Cash flows from operating activities (A)	**$ 42,311**	**$ 107,243**	$ 85,901	$ 57,521
Net income (loss) (B)	**78,924**	**110,688**	(149,205)	(2,408)
Actual cash distributions paid				
Interest on subordinated notes	**7,923**	**36,560**	36,235	26,464
Dividends (C)	**5,463**	**24,693**	24,665	16,985
Excess of cash flows from operating activities over dividends paid (A-C)	**36,848**	**82,550**	61,236	40,536
Excess (shortfall) of net income over dividends paid (B-C)	**73,461**	**85,995**	(173,870)	(19,393)

As illustrated in the table above, the Company has historically generated substantially more cash flows from operating activities 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 at exchange rates that were significantly more favorable than current levels of currency exchange rates during the periods presented above through approximately September 2008. In the fourth quarter of 2008, the Canadian dollar weakened significantly when compared to the U.S. dollar and the exchange rates were more consistent with the rates in the Company's forward currency contracts. 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 for acquisitions and other growth opportunities at existing Projects.

Net income (loss) includes large non-cash fluctuations in the fair value of derivative instruments which do not affect cash flows that may be distributed to shareholders. Excluding the change in fair value of derivative instruments, net income (loss) for the three and twelve months ended December 31, 2008 would have been $32,428 and $77,651, respectively. Accordingly, management does not view the comparison of net income (loss) to cash dividends to be a meaningful measure of the Company's historical or future ability to pay cash dividends to its shareholders.

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)

	2007[1]				2008			
	Q1	Q2	Q3	Q4	Q1	Q2	Q3	Q4
Project revenues	72,933	75,841	81,387	76,030	80,028	81,830	84,145	88,219
Net income (loss)	(32,047)	(24,188)	(18,728)	(74,243)	5,665	(40,055)	66,166	78,924
Cash flow from operating activities	18,782	11,927	8,007	47,184	27,429	30,328	7,176	42,311
Cash distributions	13,964	15,069	15,695	16,661	16,221	16,197	15,448	13,386
Cash available for distribution	21,021	4,816	11,975	42,305	29,812	27,219	9,520	37,177
Payout ratio	66%	313%	131%	39%	54%	60%	162%	36%
Per IPS statistics								
Net income (loss) – basic	(0.52)	(0.39)	(0.30)	(1.21)	0.09	(0.65)	1.08	1.30
Net income (loss) – diluted	(0.52)	(0.39)	(0.30)	(1.21)	0.09	(0.65)	1.00	1.20
Cash flow from operating activities	0.31	0.19	0.13	0.77	0.45	0.49	0.12	0.69
Cash available for distribution, US$	0.34	0.08	0.19	0.69	0.48	0.44	0.16	0.61
Cash available for distribution, Cdn$	0.40	0.09	0.20	0.68	0.49	0.45	0.16	0.74
Distributions, US$	0.23	0.25	0.26	0.27	0.26	0.26	0.25	0.22
Distributions, Cdn$	0.27	0.27	0.27	0.27	0.27	0.27	0.26	0.27

1 Certain 2007 figures have been reclassified to conform to the financial statement presentation adopted in 2008.

Liquidity and Capital Resources

OVERVIEW

The Company's primary source of cash and cash equivalents is distributions from the Projects. A significant portion of the cash received from Project distributions is distributed in the form of interest and dividends to holders of the IPSs, the separate Subordinated Notes and the Debentures. The Company may fund future acquisitions with a combination of cash on hand, the issuance of additional debt or equity securities and the incurrence of privately-placed bank or institutional 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 distributions to IPS holders 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 2009 for capital expenditures or other required investments. In addition, there are no debt instruments with significant maturities or refinancing requirements expected in 2009. See "Outlook" in this MD&A for information about changes in expected distributions from the Company's Projects in 2009.

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.

Outstanding amounts under the credit facility bear interest at the London Interbank Offered Rate ("LIBOR") plus an applicable margin between 0.875% and 1.625% that varies based on the credit ratio of a subsidiary of the Company. At December 31, 2008, the applicable margin is currently 0.875%.

As of December 31, 2008, $36,442 was allocated, but not drawn, to support letters of credit for contractual credit support at several Projects. 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 has executed an interest rate swap to fix the interest rate at 3.3% through November 2011 for $40 million of this borrowing.

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 ratios and not on balance sheet ratios. The facility is secured by pledges of assets and interests in certain subsidiaries. The Company expects to be in compliance with the covenants of the credit facility for at least the next 12 months.

Management expects to refinance and increase the size of the term loan at Auburndale within the next 12 to 24 months and will use a portion of the proceeds from the refinancing to repay borrowings under the credit facility, although the refinancing is not required under either the credit facility or the existing non-recourse Project loan. In addition, the Company may use excess operating cash flow to periodically reduce borrowings under the credit facility.

PROJECT-LEVEL DEBT

The following table summarizes the maturities of Project-level debt in thousands of U.S. dollars. The amounts represent the Company's proportionate share of the non-recourse Project-level debt balances at December 31, 2008 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. The range of interest rates presented represents the rates in effect at December 31, 2008.

	Range of Interest Rates	Total Remaining Principal Repayments	2009	2010	2011	2012	2013	Thereafter
Consolidated and proportionately consolidated Projects:								
Chambers	2.8%-8.4%	134,146	10,568	12,051	12,794	13,676	13,783	71,274
Path 15	7.9%-9.0%	168,867	7,508	7,480	7,987	8,667	9,402	127,823
Mid-Georgia	5.0%-9.0%	39,661	2,891	3,161	3,562	3,963	4,143	21,941
Topsham	9.5%	45	45	–	–	–	–	–
Auburndale[1]	4.1%	35,000	3,500	9,800	9,800	7,000	4,900	–
Total consolidated and proportionately consolidated Projects		377,719	24,512	32,492	34,143	33,306	32,228	221,038
Equity and cost method Projects:								
Delta-Person	2.8%	13,594	1,098	1,147	1,220	1,308	1,403	7,418
Selkirk	9.0%	31,997	8,122	8,247	10,188	5,440	–	–
Gregory	5.3%-6.0%	18,942	1,668	1,757	1,901	2,044	2,205	9,367
Total equity and cost method Projects		64,533	10,888	11,151	13,309	8,792	3,608	16,785
Total all Projects		442,252	35,400	43,643	47,452	42,098	35,836	237,823

1 In addition to the amount in this table, as of December 31, 2008, the Company has $55 million outstanding on its credit facility incurring interest at a rate of 1.8% for the unhedged portion and 3.3% for the hedged portion related to the acquisition of Auburndale on November 21, 2008.

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, 2008, Restricted Cash at consolidated and proportionately consolidated Projects totaled $25.4 million. 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.

CONTRACTUAL OBLIGATIONS

Contractual obligations of the Company as at the period ended December 31, 2008 are presented in the table below.

		Payments due by period			
	Total	2009	2010-2011	2012-2013	Thereafter
Long-term debt, including current portion (a)	$ 432,719	$ 79,512[1]	$ 66,635	$ 65,534	$ 221,038
Subordinated notes (b)	320,974	–	–	–	320,974
Convertible debentures (c)	49,261	–	49,261	–	–
Head office lease (d)	1,857	280	579	607	391
Total contractual obligations	$ 804,811	$ 79,792	$ 116,475	$ 66,141	$ 542,403

1 The $55 million outstanding on the Company's credit facility may be extended, at the Company's option, until the maturity of the credit facility in August 2012.

(a) Long-Term Debt, including current portion

Long-term debt represents the Company's consolidated and proportionately consolidated share of Project long-term debt and amounts outstanding under the Company's credit facility. The amount presented excludes the net unamortized purchase price adjustment of $12,756 related to the fair value of debt assumed in the Path 15 acquisition. Project debt is non-recourse to the Company and is amortized during the term of the respective revenue generating contracts of the Projects. The range of interest rates on long-term Project debt at December 31, 2008 was 2.06% to 9.5%.

(b) Subordinated Notes

As of December 31, 2008, the Company had $320,974 outstanding principal amount of Subordinated Notes due 2016. The notes pay interest only at a rate of 11% until their maturity.

(c) Convertible Debentures

The Debentures pay interest semi-annually on April 30 and October 31 each year, commencing on April 30, 2007. The Debentures mature on October 31, 2011 and are convertible into approximately 80.6452 IPSs per Cdn$1,000 principal amount of Debentures, at any time, at the option of the holder, representing a conversion price of Cdn$12.40 per IPS.

(d) Head office lease

Pertains to the lease payments associated with the Company's Boston, MA head office lease entered into on April 1, 2007 and expires on March 31, 2015.

PROJECT CONTRACTS

Each Project typically has a set of contracts that includes 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.
- 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 for 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 30, 2009, which is available on SEDAR's website at www.sedar.com.

Information Regarding Guarantors

The Subordinated Notes and the Debentures are secured by a pledge of the Company's membership interests in Holdings and are guaranteed by Holdings and Teton Power Funding, LLC, Epsilon Power Funding, LLC, MP Power LLC, Teton East Coast Generation LLC, Teton Fuels Mid-Georgia LLC, Teton Selkirk LLC, Badger Power Generation I LLC, Badger Power Generation II LLC, Baker Lake Hydro LLC, Dade Investment, L.P., Geddes II Company LLC, Geddes Cogeneration Company LLC, MEP Rumford, LLC, NCP Dade Power LLC, NCP Houston Power LLC, NCP Pasco LLC, NCP Perry LLC, Olympia Hydro LLC, Onondaga Cogeneration Limited Partnership, 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, 2008 is presented in the table below in thousands of U.S. dollars. 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.

	Atlantic Power Corporation	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	Consolidation Adjustments	Consolidated
Income Statement – Year Ended December 31, 2008					
Project revenue	–	11,773	322,448	–	334,221
Project expenses	–	44	237,339	–	237,383
Project other income (expense)	(161)	5,909	29,644	–	35,392
Project income (loss)	(161)	17,638	114,753	–	132,230
Dividends received	65,715	124,489	–	(190,204)	–
Administrative and other expenses	(38,674)	47,693		–	9,019
Income (loss) before income taxes	104,228	94,434	114,753	(190,204)	123,211
Income taxes	28,022	(141)	(15,358)	–	12,523
Income (loss)	76,206	94,575	130,111	(190,204)	110,688
Balance sheet – December 31, 2008					
Current assets	(17,144)	64,009	122,777	(20,177)	149,465
Investments in guarantor subsidiaries	588,626	–	–	(588,626)	–
Investment in non-guarantor subsidiaries	–	604,457	–	(604,457)	–
Other non-current assets	(2,323)	1,898	938,784	63,766	1,002,125
Total non-current assets	586,303	606,355	938,784	(1,129,317)	1,002,125
Total assets	569,159	670,364	1,061,561	(1,149,494)	1,151,590
Current liabilities	12,383	64,794	73,640	(20,177)	130,640
Non-current liabilities	425,603	16,944	383,464	–	826,011
Shareholders' equity	131,173	588,626	604,457	(1,129,317)	194,939
Total liabilities and shareholders' equity	569,159	670,364	1,061,561	(1,149,494)	1,151,590

Project Portfolio

The following table outlines the Company's portfolio of power generating and transmission assets as of March 30, 2009 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	Primary Location	Fuel Type	Total MW	Ownership Interest[1]	Acctg Tmt[2]	Net MW[3]	Electricity Off-Taker	PPA Expiry	Off-Taker S&P Credit Rating
Auburndale	Florida	Natural gas	155	100.0%	C	155	Progress Energy Florida	2013	BBB +
Badger Creek	California	Natural gas	46	50.0%	P	23	Pacific Gas & Electric	2011	BBB+
Chambers	New Jersey	Coal	262	40.0%	P	89[4]	Atlantic City Electric	2024	BBB
						16	DuPont	2024	A
Delta-Person	New Mexico	Natural gas	132	40.0%[5]	E	53	PNM	2020	BB-
Gregory	Texas	Natural gas	400	17.1%	Cost	59	Fortis	2013	A-
						9	Sherwin Alumina	2020	N/R
Koma Kulshan	Washington	Hydro	13	49.8%	P	6	Puget Sound Energy	2037	BBB
Lake	Florida	Natural gas	121	100.0%	C	121	Progress Energy Florida	2013	BBB+
Mid-Georgia	Georgia	Natural gas	308	50.0%	P	154	Georgia Power	2028	A
Orlando	Florida	Natural gas	129	50.0%	P	46	Progress Energy Florida	2023	BBB+
						19	Reedy Creek Improvement District	2013	A-[10]
Pasco	Florida	Natural gas	121	100.0%	P	121	TECO	2018	BBB-
Path 15	California	Transmission	N/A[8]	100.0%	C	N/A[8]	California Utilities via CAISO[7]	N/A[8]	BBB+ to A[9]
Rumford	Maine	Coal/biomass	85	23.5%[5]	E	20	Rumford Paper Co.	2009	N/R
Selkirk	New York	Natural gas	345	18.5%[5]	Cost	49	Consolidated Edison	2014	A-
						15	Merchant	N/A	N/A
Stockton	California	Coal	55	50.0%	P	24	Pacific Gas & Electric	2010	BBB+
						3	Corn Products Int'l	2010	BBB
Topsham[6]	Maine	Hydro	14	50.0%	P	7	Central Maine Power	2011	BBB+

1 Except as otherwise noted, economic interest represents the percentage ownership interest in each Project held indirectly by the Company.
2 Accounting treatment: C – Consolidated; P – Proportionate consolidation; E – Equity method; Cost – Cost method.
3 Represents the interest of the Company in each Project's electricity generation capacity based on the Company's economic interest.
4 Includes separate power sales agreement in which the Project and Atlantic City Electric ("ACE") share profits on merchant sales of electricity not purchased by ACE under the base PPA.
5 Represents the Company's estimate of its share of the cash flow from the project.
6 The Company owns its interest in this Project as a lessor.
7 California utilities pay Transmission Access Charges ("TACs") to California Independent System Operator ("CAISO"), which allocates the payments among owners of transmission and Transmission System Rights, such as Path 15, in accordance with the Project's FERC-approved annual revenue requirement.
8 Path 15 is an 84-mile, 500-kilovolt transmission line in California. The Project is a FERC-regulated asset with a FERC-approved regulatory life of 30 years, through 2034.
9 The largest payers of TACs supporting Path 15's annual revenue requirement and their S&P credit ratings are PG&E (BBB+), SoCal Ed (BBB+) and SDG&E (A). CAISO imposes minimum credit quality requirements of A or better for all participants unless collateral is posted per CAISO imposed schedule.
10 Rating from Fitch of Reedy Creek bonds.

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 Holdings receives from the Projects are made net of capital expenditures needed at the Projects. The Company has only injected funds into the Projects for significant elective 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 have planned outages to complete major maintenance work that will prolong the life, and ensure efficient and reliable operation of the assets. Major overhaul inspections are planned at Badger, Chambers and Selkirk. The principal maintenance activity at Chambers will be a major overhaul of the Project's steam turbine which occurs approximately every eight years. Please refer to "Outlook" in this MD&A for details of impacts to distributions expected from the Project. Selkirk will be conducting major overhaul inspections of two of its three gas turbines. 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. Major maintenance costs associated with the major gas turbine overhaul at Badger are paid for by the operator of the plant based on a levelized O&M fee they are paid by the Project. A minor inspection and overhaul is currently underway at Gregory and a minor inspection and overhaul is scheduled for later in the year at Auburndale. Both Gregory and Auburndale have long-term service agreements in place with steady payments over time that cover a substantial portion of the overhaul cost. 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.

Related Party Transactions

The Manager has been engaged under the Management Agreement to provide certain management and administrative services to the Company, for which it is paid: (1) a base management fee ($356 for 2008), which is adjusted annually for inflation and when acquisitions increase the scope of the Manager's responsibilities under the agreement; (2) a reimbursement of costs; and (3) an incentive fee equal to 25% of the excess in distributions paid to IPS holders and Former Investors during the year above Cdn$1.00 per IPS ($864 in 2008). The Management Agreement has an initial term of 20 years expiring in 2024. In addition, the Path 15 Project directly pays the Manager an annual fee of $266, which is subject to adjustment for inflation.

The Manager receives administrative and office support services from ArcLight under a management support agreement executed in November 2004 among the Manager, ArcLight and the Company. This agreement also requires the ArcLight Funds and their affiliates to give the Manager the opportunity to pursue, on behalf of the Company, investment opportunities that do not fit within the investment guidelines for the ArcLight Funds or other investment funds managed by ArcLight or its affiliates.

The Manager is owned indirectly by subsidiaries of the ArcLight Funds, which in conjunction with a subsidiary of Caithness, owned 41.9% of Holdings' common membership interest immediately after the IPO, but reduced their interest to 29.9% in October 2005 and further reduced their interest to approximately 14% in October 2006. In February 2007, the Company acquired all of the remaining interest of the Former Investors in Holdings.

On November 21, 2009, the Company acquired Auburndale from an entity owned by the ArcLight Funds and CDP. See "Recent Developments" in this MD&A for additional details.

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 risk of the cash flows in the estimate, including when applicable, the credit risk of the counterparty that is contractually obligated to purchase electricity or steam from the Project. No significant changes in the method used to measure accounting estimates have occurred since December 31, 2007.

Changes in Accounting Policies

FINANCIAL INSTRUMENTS – PRESENTATION AND DISCLOSURE

Effective January 1, 2008, the Company adopted Canadian Institute of Chartered Accountants ("CICA") Handbook Section 3862, "Financial Instruments – Disclosures" and Handbook Section 3863, "Financial Instruments – Presentation".

Section 3862 requires entities to provide disclosures in their financial statements that enable users to evaluate the significance of financial instruments on the entity's financial position and its performance and the nature and extent of risks arising from financial instruments to which the entity is exposed during the period and at the balance sheet date, and how the entity manages those risks.

Section 3863 establishes standards for presentation of financial instruments and non-financial derivatives. It deals with the classification of financial instruments, from the perspective of the issuer, between liabilities and equity, the classification of related interest, dividends, losses and gains, and circumstances in which financial assets and financial liabilities are offset.

The adoption of these standards did not have any impact on the classification and valuation of the Company's financial instruments. The new disclosures pursuant to these new Handbook Sections are included in Note 14 to the Audited Consolidated Financial Statements for the year ended December 31, 2008.

CAPITAL DISCLOSURES

Effective January 1, 2008, the Company adopted the new recommendations of the CICA Handbook Section 1535, "Capital Disclosures". This new Handbook Section establishes standards for disclosing information about an entity's capital and how it is managed. It requires the disclosure of information about an entity's objectives, policies and processes for managing capital. These new disclosures are included in Note 15 to the Audited Consolidated Financial Statements for the year ended December 31, 2008.

RECENTLY ISSUED ACCOUNTING STANDARDS

In February 2008, the Canadian Accounting Standards Board announced the adoption of International Financial Reporting Standards ("IFRS") for publicly accountable enterprises in Canada. Effective January 1, 2011, the Company will be required to convert from Canadian GAAP to IFRS. Management has begun to develop plans to implement the new standards and cannot at this time reasonably estimate the impact of adopting IFRS on the Company's consolidated financial statements.

CICA Handbook Section 3064, "Goodwill and Intangible Assets", 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 Company will adopt the new Handbook Section on January 1, 2009 and is currently assessing the impact that the adoption of these standards will have on its consolidated financial statements.

On January 20, 2009 the Emerging Issues Committee ("EIC") of the CICA issued 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. The Company will adopt this recommendation in its fair value determinations as of March 31, 2009 and is currently assessing the impact of this change on its consolidated financial statements.

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 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 IAS 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 is currently evaluating the impact of the adoption of these sections.

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:

	2008	2007
Change in fair value of derivative instruments		
Chambers power purchase agreement	$ 74,608	$ (106,113)
Onondaga indexed swap and hedge	(10,844)	(20,290)
Project-level interest rate swaps	(5,325)	(1,974)
Project-level natural gas swaps	(3,378)	–
	$ 55,061	$ (128,377)

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) 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 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, 2008, a 10% change in the projected average forward power prices through the term of PPA expiring in 2024 would change the fair value of the PPA by approximately $27 million.

ONONDAGA INDEXED SWAP AND HEDGE

A swap agreement ("Indexed Swap") between a utility company and Onondaga, which had replaced Onondaga's original power purchase contract, expired on June 30, 2008. The Indexed Swap was a derivative financial instrument under which the utility company made monthly payments to Onondaga based upon the differential between an indexed contract price and a market reference price for electricity. The indexed contract price fluctuated in relation to the market cost of natural gas and a prescribed index of inflation. The notional quantity of electricity for the purpose of these calculations was fixed for the full term of the Indexed Swap.

In addition, Onondaga was party to a commodity derivative instrument ("Indexed Swap Hedge"), which locked in favourable gas, power and capacity pricing under the Indexed Swap. The Indexed Swap Hedge expired on June 30, 2008.

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 has the obligation to make distributions to shareholders predominantly in Canadian dollars. Since its inception, the Company has established a hedging strategy for the purpose of reinforcing the long-term sustainability of its distributions. The Company has executed this strategy by entering into forward contracts to purchase Canadian dollars at fixed rates of exchange sufficient to make monthly distributions through December 2013 at the current annual dividend level of Cdn$0.46 per common share, as well as interest payments on the Subordinated Notes and Debentures. It is the Company's intention to periodically consider extending the length of these forward contracts. Changes in the fair value of the Company's forward contracts partially offset foreign exchange gains or losses on the U.S. dollar equivalent of the Company's Canadian dollar obligations.

The following table summarizes the Company's forward foreign currency contracts with monthly settlement terms as of December 31, 2008:

	Notional monthly amounts		
Period	Sell U.S. dollars	Buy Cdn. dollars	Average rate
2009	4,974	6,000	1.2062
2010 - 2013	5,289	6,000	1.1344

In addition to the forward contracts in the table above that settle on a monthly basis, the Company has executed forward contracts to purchase Canadian dollars at fixed rates of exchange sufficient to make semi-annual payments on the Debentures. The contracts provide for the purchase of Cdn$1.9 million in April and in October of 2008 through 2011 at a rate of 1.1075 Canadian dollars per U.S. dollar.

The foreign exchange forward contracts are carried at estimated fair value based on quoted market prices. Changes in the fair value of the foreign currency forward contracts are reflected in foreign exchange loss (gain) in the consolidated statements of income (loss) and deficit.

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

	2008	2007
Unrealized foreign exchange gains (losses):		
Subordinated notes and convertible debentures	$ 85,212	$ (68,419)
Forward contracts and other	(48,537)	30,703
	36,675	(37,716)
Realized foreign exchange gains on forward contract settlements	8,044	7,574
	$ 44,719	$ (30,142)

The following table illustrates the income (loss) that would be recorded on the Company's financial instruments in the event of a 10% hypothetical decrease in the value of the U.S. dollar compared to the Canadian dollar as of December 31, 2008:

Subordinated notes	$ (32,097)
Convertible debentures	(4,926)
Foreign currency forward contracts	33,874
	$ (3,149)

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 favourably 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 at a weighted average price of $12.24/Mmbtu.

These natural gas swaps are derivative financial instruments and were recorded in the consolidated balance sheet at fair value. 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) and deficit. The natural gas swaps at Pasco expired in December 2008.

Beginning January 1, 2009, a new 10-year PPA 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 natural gas prices 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 through June 30, 2012. The remaining 20% is purchased at spot market prices and therefore the Project is exposed to changes in natural gas prices through the termination of the fuel supply agreement.

The Company is executing 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 are recorded in other comprehensive income (loss) as they have been designated as a hedge of the risk associated with changes in market prices of natural gas.

The following table summarizes the hedge position related to natural gas needed to meet PPA requirements at Lake and Auburndale:

As of December 31, 2008	2009	2010	2011	2012	2013
Portion of gas volumes currently hedged:					
Lake:					
Contracted	50%	–	–	–	–
Financially hedged	49%	49%	–	–	–
Total	**99%**	**49%**	**0%**	**0%**	**0%**
Auburndale:					
Contracted	80%	80%	80%	40%	–
Financially hedged	13%	–	–	–	–
Total	**93%**	**80%**	**80%**	**40%**	**0%**
Average price of financially hedged volumes (per Mmbtu)					
Lake	$ 8.64	$ 7.59	$ –	$ –	$ –
Auburndale	$ 5.80	$ –	$ –	$ –	$ –

As of March 30, 2009	2009	2010	2011	2012	2013
Portion of gas volumes currently hedged:					
Lake:					
Contracted	50%	–	–	–	–
Financially hedged	49%	72%	44%	22%	22%
Total	**99%**	**72%**	**44%**	**22%**	**22%**
Auburndale:					
Contracted	80%	80%	80%	40%	–
Financially hedged	15%	9%	–	13%	22%
Total	**95%**	**89%**	**80%**	**53%**	**22%**
Average price of financially hedged volumes (per Mmbtu)					
Lake	$ 8.64	$ 7.27	$ 6.53	$ 6.60	$ 6.71
Auburndale	$ 5.68	$ 6.78	$ –	$ 6.66	$ 6.78

SUBORDINATED NOTES PREPAYMENT OPTION

The Company has 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 has determined that the redemption option is an embedded derivative that is recorded at fair value and periodic changes in fair value are recorded in other expenses in the consolidated statements of income (loss) and deficit. As of December 31, 2008, the fair value of the redemption option is zero.

Management will periodically assess this option beginning in November 2009 and will consider exercising the call option if the Subordinated Notes can be recapitalized in a manner that benefits the Company's shareholders.

INTEREST RATE SWAPS

The Company's proportionately consolidated Mid-Georgia and Chambers projects have executed interest rate swaps to economically fix a portion of the respective 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 a hedge for accounting purposes. Interest rate swaps are recorded as derivative instruments liability 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) 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) and deficit.

The Company has executed interest rate swaps on its revolving credit facility and at its proportionately consolidated Auburndale Project to economically fix a portion of its 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 existing credit facility as of November 2008. The interest rate swap termination date for Auburndale is November 30, 2009 and for the revolving credit facility is November 30, 2011.

The interest rate swap is a derivative financial instrument and is recorded in the balance sheet at fair value. Changes in the fair value of the interest rate swap are recorded in other comprehensive income (loss) as they have been designated as a hedge of the risks associated with the changes in the market interest rates.

AUCTION RATE SECURITIES

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

In February 2008, the overall market for ARSs suffered a significant decline in liquidity. Since early March 2008, most of the auctions of ARSs have been unsuccessful, resulting in the Company continuing to hold these securities and the issuers paying interest at the maximum contractual rate.

In September and November 2008, all of the Company's investments in ARS were sold, at par plus accrued interest, for $36.5 million.

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, 2008, 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.

Income taxes recoverable represents tax instalment payments made to the United States Internal Revenue Service ("IRS") and various state tax authorities, reduced by the estimated actual tax liability in those taxing jurisdictions. Through the end of 2007, the Company was required to pay instalments to the IRS based on estimates of taxable income without the benefit of the interest deduction related to the Subordinated Notes and Debentures. This requirement resulted in the payment of significant tax instalments to the IRS, followed by a refund of most of the instalment payments when the actual tax returns were filed in subsequent periods with the full benefit of the interest deductions on the Subordinated Notes and Debentures.

As of January 1, 2008, the Company is permitted to calculate tax instalment payments with the full benefit of these interest payments factored into estimated taxable income. As a result, management expects significant fluctuations in working capital related to tax instalments and subsequent refunds to decrease.

CONVERTIBLE DEBENTURES

The 6.25% convertible secured debentures ("Debentures") are due October 31, 2011. Interest is payable semi-annually in arrears on April 30 and October 31 of each year. The Debentures are convertible into 80.6452 IPS per Cdn$1,000 principal amount of Debentures, at any time, at the option of the holder, representing a conversion price of Cdn$12.40 per IPS.

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, 2008 which are expected to have a material impact on the Company's financial position or results of operations.

Outstanding Share Data

The Company had 60,937,731 and 61,470,500 IPSs outstanding at December 31, 2008 and 2007, respectively.

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. 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, 2008, the Company had acquired 558,620 IPSs at an average price of Cdn$8.78 under the terms of the issuer bid. The issuer bid will terminate on July 24, 2009 or such earlier date that the Company has acquired the maximum number of IPSs under the issuer bid. Atlantic Power will pay 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 will be canceled.

The Debentures are convertible to approximately 80.6452 IPSs per Cdn$1,000 principal amount of Debentures, at any time, at the option of the holder, representing a conversion price of Cdn$12.40 per IPS. As of December 31, 2008, approximately 4,838,700 IPSs would be required to be issued if all of the outstanding Debentures were converted to IPSs. On March 26, 2008 and March 28, 2007, the Board of Directors approved grants of notional units to acquire a maximum of 142,717 and 172,071 IPSs, respectively, under the terms of the Company's Long-Term Incentive Plan.

Outlook

Based on management projections, the Company's cash on hand and projected future cash flows from existing projects are sufficient to meet the current level of cash distributions to IPS holders 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 $90 million to $95 million for the full year 2009. This amount represents a decrease of approximately $30 million to $35 million over distributions received from the Projects in 2008.

The decrease in 2009 Project distributions has historically been included in management's long-term cash flow projections and does not change the Company's ability to continue paying distributions to shareholders at current levels.

The following decreases in projected 2009 Project distributions compared to 2008 are attributable to expiring contracts or one-time items discussed elsewhere in this MD&A:

- Shutdown of Onondaga due to the expiration of its financial swap arrangement that provided substantially all of the Project's cash flow.
- Decrease in distributions from Gregory attributable to a non-recurring debt service reserve release received in 2008.
- Decrease in distributions from Pasco resulting from the start of a new 10-year tolling agreement on January 1, 2009 that produces lower cash flows than the PPA that expired at the end of 2008.
- Lower cash distributions from Selkirk due to the expiry of one of the Project's PPAs in 2008.

During 2009, the following five Projects are expected to comprise approximately 85% of Project distributions received by the Company: Auburndale, Lake, Orlando, Path 15 and Pasco. In 2008, the following seven Projects comprised approximately 85% of Project distributions received: Lake, Pasco, Onondaga, Chambers, Gregory, Selkirk and Path 15.

In addition to the items above, following is a summary of other projections for Project distributions in 2009 and beyond:

LAKE

The Lake Project is exposed to changes in natural gas prices from the expiry of its natural gas supply contract on June 30, 2009 through the expiry of its PPA in July 2013. The Company is executing a strategy to mitigate the future exposure to changes in natural gas prices at Lake by periodically entering into financial swaps that effectively fix the price of natural gas required at the Project. Management has taken advantage of recent decreases in the market price of natural gas to make significant progress in its natural gas hedging strategy. These hedges are summarized in "Financial Instruments – Lake and Auburndale Natural Gas Swaps" in this MD&A. Management intends to continue, when appropriate, to execute additional transactions to 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-term contracts and spot market transactions.

The Company's previous guidance regarding expected distributions from the Lake Project is unchanged and is set forth in the table below:

Year	Estimated Range of Cash Distributions ($ millions)
2009	24-27
2010	24-27
2011	23-27
2012	27-33

The estimates above are based on management's current internal models as of March 30, 2009. The Company's models are based on future gas prices forecasted by Cambridge Energy Research Associates, an independent third-party energy consulting firm, which have decreased from the prices utilized in previous cash flow projections. The 2009 natural gas price exposure at Lake has been substantially hedged. In 2010, projected cash distributions at Lake would change by approximately $1.1 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 revenue component of the projected distributions from the Lake Project incorporate a forecast of the applicable Crystal River facility coal cost provided by the utility based on their internal projections. The projected annual cash distributions change by approximately $1.0 million for every $0.25/Mmbtu change in the projected price of coal.

AUBURNDALE

Increased distributions from Auburndale are the result of owning the Project for the full year of 2009 as it was acquired in November 2008. The Company previously disclosed projected distributions from Auburndale in the range of $20 million to $23 million in 2009 and $8 million to $10 million in each of the years from 2010 through 2013, when the Project's current PPA expires. Based on the current forecast, the Company now expects distributions from Auburndale in 2009 in the range of $22 million to $25 million. The increase in forecasted 2009 distributions is attributable to a $1.7 million working capital adjustment received from the previous owners and a small increase in projected electricity revenues for the Project.

Distributions received from Auburndale in the 2010 through 2013 period will be impacted by the timing and terms of the Company's expected refinancing of the project-level debt, as well as projected coal and gas prices in the forecast period. The Company has not made significant changes to its previously disclosed forecast of distributions of $8 million to $10 million per year during the 2010 to 2013 period.

The projected revenue component of the Auburndale PPA contains a component related to coal costs at the Crystal River facility as described above for the Lake Project. In addition, Auburndale is exposed to changes in natural gas prices for a portion of the Project's fuel requirements throughout the term of the PPA. The Company is 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 price of natural gas required at the Project. See "Financial Instruments – Lake and Auburndale Natural Gas Swaps" in this MD&A for additional details about hedge contracts executed as of March 30, 2009. The 2009 natural gas price exposure at Auburndale has been substantially hedged. In 2010, projected cash distributions at Auburndale would change by approximately $0.8 million per $1.00/Mmbtu change in the price of natural gas based on the current level of unhedged natural gas volumes at the Project. Management intends to continue, when appropriate, to execute additional transactions to mitigate natural gas price exposure at Auburndale in the 2010 to 2013 period.

CHAMBERS

The Company expects a 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.

The major maintenance outage requires a complete shutdown of the plant for approximately half of the second quarter of 2009. This type of outage is scheduled every seven years at the Project. The combined costs of maintenance and associated lost profit margin are expected to reduce distributions from Chambers by approximately $4 million compared to the maintenance outage in 2007. Significantly lower 2009 market power prices in the PJM region are expected to result in both lower volumes of electricity sold from the Project as well as operating margins on electricity sold under the Project's profit-sharing arrangement with the local utility.

The estimated costs for the Project to comply with New Jersey's implementation of the Regional Greenhouse Gas Initiative will reduce distributions from Chambers by approximately $2 million.

The combined impact of these factors is expected to reduce cash flows to the point that the Project's non-recourse debt does not meet a cash flow coverage ratio at a level that will allow cash to be distributed to the Company in 2009. Based on management's current projections, the Chambers Project will be able to resume distributions to the Company in the second half of 2010.

ORLANDO

Cash distributions from the Orlando Project are expected to increase in 2009 compared to 2008. The increase in projected distributions is attributable to higher volumes of electricity in 2009 than in 2008 when an unplanned outage shut the plant for approximately four months. The Project took advantage of the unplanned outage to make improvements in the efficiency of the plant, which will result in slightly higher operating margins in 2009. In addition, insurance recoveries related to the 2008 unplanned outage in the amount of $1.7 million are expected to be received by the Project in 2009.

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, 2008. 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, 2008 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. As of December 31, 2008, management evaluated, with the participation of the Chief Executive Officer and Chief Financial Officer of the Manager, the effectiveness of the Company's ICFR 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 year ended December 31, 2008.

The CEO and CFO of the Manager have limited the scope of design of ICFR to exclude the Auburndale Project, which was acquired in November 2008. In addition, the proportionately consolidated Badger Creek, Chambers, Koma Kulshan, Orlando, Stockton and Topsham Projects have been excluded from the scope of ICFR.

Risk Factors

Atlantic Power's future performance and its ability to generate sufficient cash flow to meet its monthly cash distributions to holders of IPSs, and the Common Shares and Subordinated Notes represented thereby, and to holders of Debentures, 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 IPSs, Common Shares, Subordinated Notes or Debentures or on the market price or value of IPSs, Common Shares, Subordinated Notes or Debentures. A discussion of these risks and uncertainties can be found in the Company's Annual Information Form dated March 30, 2009. The Company's annual information form is available on SEDAR's website at www.sedar.com. The following is a summary of the primary risks facing the Company:

REVENUE MAY BE REDUCED UPON EXPIRATION OR TERMINATION OF PPAS

Power generated by the Projects, in most cases, is sold under PPAs that expire at various times. In addition, these PPAs may be subject to termination in certain circumstances, including default by the Project owner or operator. When a PPA expires or is terminated, it is possible that the price received by the relevant Project for power under subsequent arrangements may be reduced significantly. It is possible that subsequent power purchase arrangements may not be available at prices that permit the operation of the Project on a profitable basis. If this occurs, the affected Project may temporarily or permanently cease operations.

THE PROJECTS DEPEND ON THEIR ELECTRICITY AND THERMAL ENERGY CUSTOMERS

Each Project relies on one or more PPAs, steam sales agreements or other agreements with one or more utilities or other customers for a substantial portion of its revenue. The amount of cash available for distribution to holders of IPSs, Common Shares and Subordinated Notes is highly dependent upon customers under such agreements fulfilling their contractual obligations. There is no assurance that these customers will perform their obligations or make required payments to the Project Operating Entities.

CERTAIN PROJECTS ARE EXPOSED TO FLUCTUATIONS IN THE PRICE OF ELECTRICITY AND FUELS

While a majority of the off-takers of the Projects are contractually obligated to purchase electricity under long-term PPAs, those Projects with power purchase arrangements based on market pricing will be exposed to fluctuations in the wholesale price of electricity. In addition, should any of the long-term PPAs expire or terminate, the Manager or the relevant Project operator will be required to either negotiate new PPAs or sell into the electricity wholesale market, in which case the prices for electricity will depend on market conditions at the time.

PREDICTING PROJECT CASH FLOWS OVER THE LONG TERM IS DIFFICULT

Due to the many uncertainties described in this risk factors section that could materially affect future revenues or expenses it can be difficult to make long-term projections of the Company's cash flows and operating margins.

OPERATIONS ARE SUBJECT TO THE PROVISIONS OF VARIOUS ENERGY LAWS AND REGULATIONS

Generally, in the United States, the Company's projects are subject to regulation by the FERC regarding the terms and conditions of wholesale service and rates, as well as by state agencies regarding PPAs entered into by QF projects and the siting of the generation facilities. The majority of the Company's generation is sold by QF projects under PPAs that required approval by state authorities.

On August 8, 2005, the Energy Policy Act of 2005 ("EPAct 2005") was enacted, which removed certain regulatory constraints on investment in utility power producers by repealing the PUHCA 1935 and enacting the PUHCA 2005. EPAct 2005 also limited the requirement that electric utilities buy electricity from QFs to certain markets that lack competitive characteristics. Finally, EPAct 2005 amended and expanded the reach of FERC's corporate merger approval authority under section 203 of the FPA. FERC has issued final rulemakings implementing these provisions of EPAct 2005.

PROJECTS ARE SUBJECT TO SIGNIFICANT ENVIRONMENTAL AND OTHER REGULATIONS

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

Environmental laws and regulations have generally become more stringent over time, and this trend may continue. In particular, the EPA has promulgated regulations under the federal Clean Air Interstate Rule ("CAIR") requiring additional reductions in nitrogen oxides, or NO_X and sulphur dioxide, or SO_2, emissions, beginning in 2009 and 2010, respectively, and has also promulgated regulations requiring reductions in mercury emissions from coal-fired electric generating units, beginning in 2010 with more substantial reductions in 2018. Moreover, certain of the states in which we operate have promulgated air pollution control regulations which are more stringent than existing and proposed federal regulations. The CAIR program underwent several legal challenges which resulted in the DC Circuit Court vacating the program on July 11, 2008. The EPA was instructed by the Court to completely overhaul the program. On December 23, 2008, the DC Circuit Court remanded, without vacature, EPA's CAIR program. EPA is currently working with the states involved in the program to reinstate it and while doing so, making changes as required in the initial Court ruling.

Under the CAIR program, regulations are under consideration that would modify the existing program of distribution of NO_X allocations at no cost to generators, to an auction-based program for all allocations.

Ongoing public concerns about emissions of carbon dioxide and other greenhouse gases ("GHG") from power plants have resulted in proposed laws and regulations at the federal, state and regional levels that, if they were to take effect substantially as proposed, would likely apply to Project operations. For example, a proposed multi-state carbon dioxide cap-and-trade program known as the Regional Greenhouse Gas Initiative ("RGGI") would apply to the Company's fossil fuel facilities in the Northeast region. The RGGI program went into effect on January 1, 2009. Two regional quarterly CO_2 auctions have already occurred. CO_2 allocations are now a trade commodity, currently averaging in the $3.50 to $4.00/ton range. The State of Florida is conducting stakeholder meetings as part of the process of developing GHG contract regulations. They have held their most recent stakeholders meeting in January, 2009. Discussion then indicated favoring a program similar to that of RGGI.

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

Under AB 32 (the California Global Warming Act of 2006) the California Air Resources Board ("CARB") is required to adopt a GHG emissions cap on all major sources (not limited to the electric sector). In order to do so, it must adopt regulations for the mandatory reporting and verification of GHG emissions and to reduce state-wide emissions of GHG to 1990 levels by 2020. This will most likely require that electric generating facilities reduce their emissions of GHG or pay for the right to emit by the implementation date of January 1, 2012. The program has yet to be finalized and the decision as to whether allocations will be distributed or auctioned will be determined in the rulemaking process that is currently underway. Discussion to date favors an allocation auction-based program.

SB 1368 added the requirement that the California Energy Commission, in consultation with the California Public Utilities Commission ("CPUC") and the CARB establish a GHG emission performance standard and implement regulations for power purchase agreements that exceed five years entered into prospectively by publicly-owned electric utilities. The legislation directs the CEC to establish the performance standard as one not exceeding the rate of GHG emitted per megawatt-hour associated with combined-cycle, gas turbine baseload generation. Provisions are under consideration in the rulemaking to allow facilities that have higher CO_2 emissions to be able to negotiate PPAs for up to a five-year period or sell power to entities not subject to SB 1368. This statute may limit Stockton's ability to extend its PPA with PG&E (which currently expires in early 2009) beyond the five-year limit.

In addition to the regional initiatives, legislation for the regulation of GHG has been introduced at the federal level and if passed, may eventually override the regional efforts with a national cap and trade program.

Significant expenditures may be required for either capital expenditures or the purchase of allowances under any or all of these programs to keep the Projects' facilities compliant with environmental laws and regulations. The Projects' PPAs do not allow for the pass through of emissions allowance or emission reduction capex costs. If it is not economical to make those expenditures, it may be necessary to retire or mothball facilities, or restrict or modify our operations to comply with more stringent standards.

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

THE PROJECTS DEPEND ON SUPPLIERS UNDER FUEL SUPPLY AGREEMENTS AND INCREASES IN FUEL COSTS MAY ADVERSELY AFFECT THE PROFITABILITY OF THE PROJECTS

Revenues in respect of the Projects may be affected by the availability, or lack of availability, of a stable supply of fuel at reasonable or predictable prices. To the extent possible, the Projects attempt to match fuel cost setting mechanisms in supply agreements to PPA energy payments formulas. To the extent that fuel costs are not matched well to PPA energy payments, increases in fuel costs may adversely affect the profitability of the Projects.

The amount of energy generated at the Projects is highly dependent on suppliers under certain fuel supply agreements fulfilling their contractual obligations. The loss of significant fuel supply agreements or an inability or failure by any supplier to meet its contractual commitments may adversely affect cash distributions by the Company.

Upon the expiry or termination of existing fuel supply agreements, the Manager or Project operators will have to renegotiate these agreements or may need to source fuel from other suppliers. There can be no assurance that the Manager or Project operators will be able to renegotiate these agreements or enter into new agreements on similar terms. Furthermore, there can be no assurance as to availability of the supply or pricing of fuel under new arrangements and it can be very difficult to accurately predict the future prices of fuel.

The amount of energy generated at the Projects is dependent upon the availability of natural gas, coal, oil or biomass. There can be no assurance that the long-term availability of such resources will remain unchanged.

U.S. FEDERAL INCOME TAX RISKS

There can be no assurance that U.S. federal income tax laws and IRS administrative policies respecting the U.S. federal income tax consequences generally applicable to a holder of Common Shares and Subordinated Notes, as represented by IPSs, will not be changed in a manner which adversely affects Non-U.S. Holders.

There is no authority that directly addresses the tax treatment of securities similar to the Subordinated Notes (i.e., as part of a unit that includes Common Shares of the Company). In light of this absence of direct authority, it cannot be concluded with certainty that the Subordinated Notes will be treated as debt for U.S. federal income tax purposes, and, although the Company takes the position that the Subordinated Notes are debt for U.S. federal income tax purposes, there can be no assurance that this position will not be challenged by the IRS. If such a challenge were sustained, some or all of the interest payments on the Subordinated Notes would be recharacterized as non-deductible distributions with respect to the Company's equity, and the Company's net taxable income, which is effectively connected income, and thus its U.S. federal income tax liability would be materially increased.

As a result, the Company's after-tax cash flow would be reduced and the Company's ability to make interest payments on Subordinated Notes and distributions with respect to Common Shares could be materially and adversely impacted.

RECENT CANADIAN FEDERAL INCOME TAX PROPOSALS

On June 22, 2007, Bill C-52, which significantly modifies the Canadian federal income tax rules applicable to certain publicly listed trusts and partnerships, received Royal Assent. An investment in IPSs does not involve a publicly listed trust or partnership, but an investment in IPSs shares certain characteristics with investments in publicly listed trust or partnership entities that are the subject of the new legislation. The proposals of October 31, 2006 first announcing the proposed rules indicated that although the details outlined therein reflected the then present intentions of the government, any aspect of these measures may be changed accordingly and possibly with retroactive effect if there should emerge structures or transactions that are clearly devised to frustrate the policy objectives underlying the proposals. Management believes that the proposed rules do not apply to the Company and do not alter the tax consequences of an investment in Common Shares and Subordinated Notes represented by IPSs. However, there is no assurance that Canadian federal income tax laws and administrative policies will not be changed in a manner that adversely affects the holders of Common shares and Subordinated Notes represented by IPSs.

Atlantic Power's future performance and its ability to generate sufficient cash flow to meet its monthly cash distributions to holders of IPSs, and the Common Shares and Subordinated Notes represented thereby, and to holders of Debentures, is 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 IPSs, Common Shares, Subordinated Notes or Debentures or on the market price or value of IPSs, Common Shares or Subordinated Notes. In addition to the summary of certain risk factors below and other information contained or incorporated by reference in this MD&A, the "Risk Factors" section in the Company's annual information form dated March 30, 2009 should be given careful consideration and is incorporated by reference herein. Additional risks and uncertainties not currently known to the Company or management of the Manager, or that the Company or management of the Manager currently consider immaterial, may also impair operations of the Company. If any such risks actually occur, the business, financial condition, or liquidity and results of operations of the Company, and the ability of the Company to make distributions on the IPSs, the Common Shares and Subordinated Notes represented thereby, and the Debentures, could be materially adversely affected. 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.atlanticpowercorporation.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 Month Periods Ended December 31, 2008 – Supplementary Financial Information" in this MD&A for additional details about the supplementary information.

Project Adjusted EBITDA[1] (in thousands of U.S. dollars) (unaudited)	Three months ended December 31, 2008	Three months ended December 31, 2007	Years ended December 31, 2008	Years ended December 31, 2007
Adjusted EBITDA[1] from consolidated and proportionately consolidated Projects				
Auburndale	**4,461**	–	**4,461**	–
Badger Creek	**1,098**	1,314	**3,762**	4,109
Chambers	**6,066**	4,962	**27,603**	28,028
Koma Kulshan	**259**	323	**912**	1,196
Lake	**7,830**	6,633	**32,892**	28,042
Mid-Georgia	**590**	982	**4,206**	5,587
Onondaga	**(467)**	4,681	**7,865**	21,966
Orlando	**5,170**	2,214	**8,206**	8,336
Pasco	**4,660**	3,633	**21,953**	14,225
Stockton	**777**	968	**1,780**	3,505
Topsham	**958**	470	**2,629**	2,031
Path 15	**6,317**	8,175	**28,872**	31,564
Other	**384**	248	**964**	987
Total adjusted EBITDA[1] from consolidated and proportionately consolidated Projects	**38,103**	34,603	**146,105**	149,576
Amortization	**12,564**	9,792	**49,267**	48,188
Interest expense, net	**7,428**	8,868	**26,473**	26,975
Change in the fair value of derivative instruments	**(77,493)**	38,730	**(55,061)**	128,377
Other expense	**18,795**	77,934	**13,330**	67,897
Earnings (loss) from consolidated and proportionately consolidated Projects	**76,809**	(100,721)	**112,096**	(121,861)
Adjusted EBITDA[1] from equity and cost method Projects				
Delta-Person	**536**	558	**2,012**	2,255
Jamaica	**–**	–	**–**	2,381
Gregory[2]	**1,478**	–	**10,411**	–
Rumford	**601**	655	**2,395**	2,585
Selkirk[2]	**2,834**	4,821	**8,032**	10,350
Other	**–**	16	**(164)**	(205)
Total adjusted EBITDA[1] from equity and cost method Projects	**5,449**	6,050	**22,686**	17,366
Amortization	**454**	463	**1,824**	1,948
Interest expense, net	**190**	223	**728**	1,172
Other expense	**–**	–	**–**	5,115
Income tax	**–**	73	**–**	665
Income from cost and equity investments	**4,805**	5,291	**20,134**	8,466
Project income				
Total adjusted EBITDA[1] from all Projects	**43,552**	40,653	**168,791**	166,942
Amortization	**13,018**	10,255	**51,091**	50,136
Interest expense, net	**7,618**	9,091	**27,201**	28,147
Change in the fair value of derivative instruments	**(77,493)**	38,730	**(55,061)**	128,377
Other expense	**18,795**	77,934	**13,330**	73,012
Income taxes	**–**	73	**–**	665
Project income (loss) as reported in the statement of income	**81,614**	(95,430)	**132,230**	(113,395)
Earnings (loss) from consolidated and proportionately consolidated Projects	**76,809**	(100,721)	**112,096**	(121,861)
Equity income from equity and costs investments	**4,805**	5,291	**20,134**	8,466
Project income (loss) as reported in the statement of income	**81,614**	(95,430)	**132,230**	(113,395)

1 Adjusted EBITDA is not a measure recognized under GAAP and does not have a standardized meaning prescribed by GAAP. Adjusted EBITDA is defined as earnings before interest, taxes, depreciation, amortization (including non-cash impairment charges) and changes in fair value of derivative instruments. Management uses adjusted EBITDA at the Projects to provide comparative information about Project performance. See "Non-GAAP Financial Measures" in this MD&A.

Reconciliation of Project Distributions (in thousands of U.S. dollars)

For the year ended December 31, 2008	Adjusted EBITDA[1]	Repayment of long-term debt	Interest expense, net	Capital expenditures	Change in working capital & other items	Project distribution received
Consolidated and proportionately consolidated Projects						
Auburndale	4,461	–	(225)	–	1,764	6,000
Badger Creek	3,762	–	(3)	–	441	4,200
Chambers	27,603	(9,639)	(8,537)	(145)	1,414	10,696
Koma Kulshan	912	–	4	(192)	(528)	196
Lake	32,892	–	33	(814)	(931)	31,180
Mid-Georgia	4,206	(2,646)	(3,271)	11	1,700	–
Onondaga	7,865	–	81	(3)	11,693	19,636
Orlando	8,206	(3,468)	16	(306)	(1,048)	3,400
Pasco	21,953	(12,038)	(978)	(175)	10,883	19,645
Stockton	1,780	–	(9)	(61)	(1,460)	250
Topsham	2,629	(2,400)	(193)	–	(36)	–
Path 15	28,872	(8,086)	(13,232)	–	156	7,710
Other	964	–	(159)	(113)	(290)	402
Total consolidated and proportionately consolidated Projects	146,105	(38,277)	(26,473)	(1,798)	23,758	103,315
Equity and cost method Projects						
Delta-Person	2,012	(1,027)	(738)	–	(247)	–
Gregory	10,411	(1,807)	–	(133)	1,940	10,411
Rumford	2,395	–	2	(187)	524	2,734
Selkirk	8,032	(6,915)	–	(60)	6,974	8,031
Other	(164)	–	8	–	156	–
Total equity and cost method Projects	22,686	(9,749)	(728)	(380)	9,347	21,176
Total all Projects	168,791	(48,026)	(27,201)	(2,178)	33,105	124,491

1 Adjusted EBITDA is not a measure recognized under GAAP and does not have a standardized meaning prescribed by GAAP. Adjusted EBITDA is defined as earnings before interest, taxes, depreciation, amortization (including non-cash impairment charges) and changes in fair value of derivative instruments. Management uses Adjusted EBITDA at the Projects to provide comparative information about Project performance. See "Non-GAAP Financial Measures" in this MD&A.

MANAGEMENT'S RESPONSIBILITY FOR FINANCIAL STATEMENTS

to the Shareholders of Atlantic Power Corporation

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 Atlantic Power Management, LLC, 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 accounting principles, 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
President and CEO

Patrick Welch
Chief Financial Officer

AUDITORS' REPORT TO THE SHAREHOLDERS

We have audited the consolidated balance sheets of Atlantic Power Corporation as at December 31, 2008 and 2007 and the consolidated statements of income (loss) and deficit, comprehensive income (loss) and cash flows for each of 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, 2008 and 2007 and the results of its operations and its cash flows for each of the years then ended in accordance with Canadian generally accepted accounting principles.

KPMG LLP

Chartered Accountants, Licensed Public Accountants
Toronto, Canada
March 30, 2009

CONSOLIDATED BALANCE SHEETS

(In thousands of U.S. dollars)

	December 31, 2008	2007
ASSETS		
Current assets:		
Cash and cash equivalents	$ 50,071	$ 55,990
Restricted cash	25,372	38,304
Accounts receivable	48,128	38,134
Current portion of derivative instruments asset (Note 14)	15,001	23,753
Prepayments, supplies and other	8,593	10,020
Income taxes recoverable	2,300	10,261
	149,465	176,462
Property, plant and equipment (Note 5)	433,542	413,040
Transmission system rights (Note 7)	203,833	210,972
Other intangible assets (Note 7)	180,186	125,976
Long-term investments (Note 8)	63,765	64,815
Goodwill (Note 6)	8,918	8,918
Derivative instruments asset (Note 14)	109,482	79,611
Other assets	2,399	2,053
	$1,151,590	$ 1,081,847
LIABILITIES AND SHAREHOLDERS' EQUITY		
Current liabilities:		
Accounts payable and accrued liabilities	$ 31,783	$ 32,886
Current portion of long-term and short-term debt	79,512	36,926
Current portion of derivative instruments liability (Note 14)	10,031	7,822
Interest payable on Subordinated Notes and Debentures	3,455	4,271
Dividends payable	1,918	2,127
Other	3,941	2,637
	$ 130,640	$ 86,669
Long-term debt (Note 11)	364,155	356,188
Subordinated Notes (Note 12)	310,584	386,092
Convertible Debentures (Note 13)	48,790	59,912
Derivative instruments liability (Note 14)	22,132	8,044
Future tax liability (Note 16)	44,883	46,914
Other liabilities	35,467	24,253
Shareholders' equity:		
Common Stock (Note 17)	214,888	216,636
Accumulated other comprehensive loss (Note 20)	(3,204)	–
Deficit	(16,745)	(102,861)
	194,939	113,775
Commitments and contingencies (Note 22)		
Subsequent events (Note 23)		
	$1,151,590	$ 1,081,847

See accompanying notes to consolidated financial statements.

On behalf of the Board:

Director

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, 2008	2007
Project revenue:		
Energy sales	$ 148,376	$ 147,486
Energy capacity revenue	145,538	121,119
Transmission services	31,528	34,524
Other	8,779	3,063
	334,221	306,192
Project expenses:		
Fuel	133,362	109,217
Operations and maintenance	41,387	38,467
Project operator fees and expenses	13,367	8,933
Depreciation and amortization	49,267	48,188
	237,383	204,805
Project other income (expense):		
Change in fair value of derivative instruments (Note 14)	55,061	(128,377)
Income from long-term investments	20,134	8,466
Asset impairments (Notes 5 and 6)	(18,471)	(71,726)
Interest, net	(26,473)	(26,975)
Other project income	5,141	3,830
	35,392	(214,782)
Project income (loss)	132,230	(113,395)
Administrative and other expenses:		
Management fees and administration	10,012	8,185
Interest, net	43,275	44,282
Foreign exchange (gain) loss	(44,719)	30,142
Other expenses, net	451	975
	9,019	83,584
Income (loss) before income taxes	123,211	(196,979)
Income tax expense (benefit) (Note 16)	12,523	(47,774)
Net income (loss)	110,688	(149,205)
Retained earnings (deficit), beginning of year	(102,861)	71,009
Redemption of IPSs (Note 17)	275	–
Dividends paid	(24,847)	(24,665)
Deficit, end of year	$ (16,745)	$ (102,861)
Net income (loss) per share – basic (Note 19)	$ 1.81	$ (2.43)
Net income (loss) per share – diluted (Note 19)	$ 1.67	$ (2.43)

Consolidated Statements of Comprehensive Income (Loss)

(In thousands of U.S. dollars)

	2008	2007
Net income (loss)	$ 110,688	$ (149,205)
Other comprehensive (loss)		
Unrealized loss on natural gas and interest rate cash flow hedges, net (Note 20)	(3,204)	–
Comprehensive income (loss)	$ 107,484	$ (149,205)

See accompanying notes to consolidated financial statements.

CONSOLIDATED STATEMENTS OF CASH FLOWS

(In thousands of U.S. dollars)

	Years Ended December 31, 2008	2007
Cash flows from operating activities:		
Net income (loss)	$ 110,688	$ (149,205)
Items not involving cash:		
Depreciation and amortization	49,267	47,602
(Gain) loss on sale of property, plant and equipment	(5,163)	8,923
Earnings from equity investments (Note 8)	(1,692)	1,898
Asset impairments (Notes 5 and 6)	18,471	71,726
Change in gas transportation contract commitment (Note 9)	–	(23,573)
Unrealized foreign exchange (gain) loss	(36,675)	37,716
Change in fair value of derivative instruments (Note 14)	(55,061)	131,089
Future taxes	12,535	(51,747)
Change in other operating balances	12,131	7,387
Distributions from equity investments (Note 8)	2,742	4,085
	107,243	85,901
Cash flows from (used in) financing activities:		
Redemption of IPSs	(4,676)	–
Proceeds from revolving credit facility borrowings	55,000	31,000
Repayment of revolving credit facility borrowings	–	(31,000)
Proceeds from issuance of project-level debt	35,000	48,056
Dividends paid	(24,612)	(24,342)
Repayment of long-term debt	(38,277)	(88,581)
Repayment of obligations to non-controlling interest	–	(76,888)
Cash proceeds from escrow used for redemption	–	74,433
	22,435	(67,322)
Cash flows used in investing activities:		
Acquisition, net of cash acquired (Note 3)	(141,688)	(23,213)
Proceeds from sale of equity investment	–	6,195
Purchase of property, plant and equipment	(1,798)	(17,271)
Proceeds from sale of property, plant and equipment	7,889	3,073
	(135,597)	(31,216)
Decrease in cash and cash equivalents	(5,919)	(12,637)
Cash and cash equivalents, beginning of period	55,990	68,627
Cash and cash equivalents, end of period	$ 50,071	$ 55,990
Supplemental cash flow information:		
Interest paid	$ 72,129	$ 72,248
Income taxes refunded	2,418	1,143

See accompanying notes to consolidated financial statements.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

Years ended December 31, 2008 and 2007
(In thousands of U.S. dollars, unless otherwise noted, and 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 is comprised of one common share and Cdn$5.767 principal value of 11% subordinated notes due 2016 ("Subordinated Notes").

The Company currently owns, through its wholly-owned subsidiary Atlantic Power Holdings, LLC ("Holdings") indirect interests in 14 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 Holdings 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 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 as cost (Note 8). The Company proportionately consolidates investments in which it has joint control (Note 4). The Company eliminates intercompany accounts and transactions.

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 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.

G. OTHER INTANGIBLE ASSETS

Other intangible assets include power purchase contracts and fuel supply agreements.

Power purchase agreements are valued at the time of acquisition based on the rates received under the power purchase contracts relative to projected market rates. The balances are presented net of accumulated amortization. Amortization is recorded on a straight-line basis over the remaining term of the contract. The amortization period ranges from one to 16 years. The weighted average period of amortization is 13 years.

Fuel supply agreements are valued at the time of acquisition based on the rates projected to be paid under the fuel supply agreement relative to projected market rates. The amortization period ranges from one to 16 years. The weighted average period of 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. If the power purchase contract contains capacity payments that fluctuate over the term of the contract, the Company recognizes energy capacity revenue based on the estimated average rate for the duration of the contract with the difference between cash received and revenue recognized reflected as deferred revenue.

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.

Onondaga Cogeneration, LP ("Onondaga") recognized revenue as its swap agreements settled monthly, net of any change in fair value on these swap agreements (Note 14(c)).

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 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 a hedge are measured at fair value with changes in fair value recorded in the consolidated statements of income (loss), comprehensive income (loss) and deficit. Derivative financial instruments not designated as hedges are the foreign currency forward contracts, the Indexed Swap and the Indexed Swap Hedge agreements and certain interest rate and natural gas swaps. Mark-to-market adjustments in the foreign currency forward contracts are reflected in foreign exchange loss, Indexed Swap and Indexed Swap Hedge agreements are netted and reflected as Indexed Swaps under Project revenue and adjustments in interest rate swaps are reflected in Project interest expense in the consolidated statements of income (loss), comprehensive income (loss) and deficit.

The Company has designated its natural gas forward contracts and 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. Unrealized gains or losses on the interest rate swaps designated within a designated hedging relationship are recognized in other comprehensive income.

Gains and losses on natural gas forward contracts and swaps that are designated as a hedge of fuel costs are recognized in accumulated other comprehensive loss until the hedged items are recognized in earnings as actual fuel costs are recognized.

Natural gas supply contracts in the normal course of business, in which the Company takes possession of the natural gas, are treated as executory contracts.

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 asset's estimated useful life and included in depreciation expense on the consolidated statements of income (loss), comprehensive 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 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 is required to evaluate its equity method investments to determine whether or not they are impaired when the value is considered an "other than a temporary" decline in value. The evaluation and measurement of impairments for equity method investments involve the same uncertainties as described for long-lived assets. Similarly, estimates, with respect to our equity and cost-method investments, are subjective, and the impact of variations in these estimates could be material.

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 the exchange rates in effect at the transaction date. 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 power purchase agreements, 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 Atlantic Power Management, LLC (the "Manager") are eligible to participate in the Company's Long-Term Incentive Plan ("LTIP") that was implemented in 2007, as determined by the independent members of the Board of Directors of the Company. 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 IPSs at the award date. Awards are granted in the form of notional units that have similar economic characteristics to the Company's IPSs. Notional units vest over a three-year period and are redeemed in a combination of cash and IPSs upon vesting.

Unvested notional awards are entitled to receive distributions equal to the distributions per public IPS 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 Manager 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 IPS 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 IPSs which may be issued from treasury under the LTIP is limited to one million.

2. Changes in accounting policies

A. FINANCIAL INSTRUMENTS – PRESENTATION AND DISCLOSURE

Effective January 1, 2008, the Company adopted the Canadian Institute of Chartered Accountants ("CICA") Handbook Section 3862, "Financial Instruments – Disclosures" and Handbook Section 3863, "Financial Instruments – Presentation".

Section 3682 requires entities to provide disclosures in their financial statements that enable users to evaluate the significance of financial instruments on the entity's financial position and its performance and the nature and extent of risks arising from financial instruments to which the entity is exposed during the period and at the balance sheet date, and how the entity manages those risks.

Section 3683 establishes standards for presentation of financial instruments and non-financial derivatives. It deals with the classification of financial instruments, from the perspective of the issuer, between liabilities and equity, the classification of related interest, dividends, losses and gains, and circumstances in which financial assets and financial liabilities are offset.

The adoption of these standards did not have any impact on the classification and valuation of the Company's financial instruments. The additional new disclosures pursuant to these new Handbook Sections are included in Note 14.

B. CAPITAL DISCLOSURES

Effective January 1, 2008, the Company adopted the new recommendations of the CICA Handbook Section 1535, "Capital Disclosures". This new Handbook Section establishes standards for disclosing information about an entity's capital and how it is managed. It requires the disclosure of information about an entity's objectives, policies and processes for managing capital. These new disclosures are included in Note 15.

C. RECENTLY ISSUED ACCOUNTING STANDARDS

In February 2008, the Canadian Accounting Standards Board announced the adoption of International Financial Reporting Standards ("IFRS") for publicly accountable enterprises in Canada. Effective January 1, 2011, the Company will be required to convert from Canadian GAAP to IFRS. Management has begun to develop plans to implement the new standards, and cannot at this time reasonably estimate the impact of adopting IFRS on the Company's consolidated financial statements.

CICA Handbook Section 3064, "Goodwill and Intangible Assets", 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 Company will adopt the new Handbook Section on January 1, 2009 and is currently assessing the impact that the adoption of these standards will have on its consolidated financial statements.

On January 20, 2009 the Emerging Issues Committee ("EIC") of the CICA issued 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. The Company will adopt this recommendation in its fair value determinations effective January 1, 2009 and is currently assessing the impact of this change on its consolidated financial statements.

In January 2009, the CICA issued 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 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 IAS 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 is currently evaluating the impact of the adoption of these sections.

3. Acquisitions and divestments

A. 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 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. Total cash paid for the acquisition, less cash acquired, during 2008 was $141,688. In 2009, the Company received a working capital adjustment from the sellers in the amount of $1,780, resulting in a final purchase price of $139,908.

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

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

B. PASCO ACQUISITION

In December 2007, the Company acquired substantially all of the remaining 50.1% interest in the Pasco Project from its existing partners. During 2008, management finalized the allocation of purchase price to the net assets acquired with no significant changes from the preliminary allocation in the following table:

Working capital	$ 4,466
Other long-term assets	20,518
Total purchase price	24,984
Less: cash acquired	(1,771)
Cash paid, net of cash acquired	$ 23,213

C. JAMAICA PRIVATE POWER COMPANY LTD. DIVESTMENT

In 2007, a subsidiary of the Company sold its equity investment in the Jamaica Project for $6.2 million. The carrying value of the equity investment exceeded the sales price and, accordingly, an impairment charge in the amount of $5.1 million was recorded in income from long-term investments in the consolidated statement of income (loss), comprehensive loss and deficit for the year ended December 31, 2007.

4. Joint venture investments

The Company accounts for seven entities under proportionate consolidation:

Entity name	Proportion consolidated
Badger Creek Limited	50.0%
Chambers	40.0%
Koma Kulshan Associates	49.8%
Mid-Georgia Cogen LP	50.0%
Orlando Cogen Limited LP	50.0%
Stockton Cogen Company	50.0%
Topsham Hydro Assets	50.0%

The following summarizes the balance sheets at December 31, 2008 and 2007, and operating results and distributions paid to the Company for the years ended December 31, 2008 and 2007 for the Company's proportionate share of the seven entities:

	Company's share	
	2008	2007
Assets		
Current Assets	**$ 63,055**	$ 57,045
Non-current assets	**426,047**	397,951
	$ 489,102	$ 454,996
Liabilities		
Current Assets	**$ 27,950**	40,498
Non-current assets	**141,356**	184,173
	$ 169,306	$ 224,671
Operating results		
Revenue	**$ 160,410**	192,935
Net income (loss)	**73,728**	(153,926)
Distributions paid to the Company	**$ 18,742**	$ 29,003

5. Property, plant and equipment

	2008	2007
Cost	**$ 514,020**	$ 477,042
Less accumulated depreciation	**(80,478)**	(64,002)
	$ 433,542	$ 413,040

Depreciation expense of $15,801 and $18,014 was recorded for the years ended December 31, 2008 and 2007, 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 will not be recovered and recorded a pre-tax long-lived asset impairment of $18,471, which represents the entire value of the Project's property, plant and equipment at December 31, 2008. The Company has extended the PPA through March 2010 and is also considering a variety of options to recover some of its remaining investment in the Stockton project. The impairment charge is included in asset impairments in the consolidated statements of income (loss), comprehensive income (loss) and deficit.

6. Goodwill

	Path 15	Chambers	Total
Goodwill, beginning of year 2007	$ 7,432	$ 71,726	$ 79,158
Adjustments to purchase price allocations	1,486	–	1,486
Impairment loss	–	(71,726)	(71,726)
Goodwill, end of year 2007 and 2008	$ 8,918	–	$ 8,918

The impairment of goodwill in the amount of $71,726 at Chambers in 2007, resulted from the significant increase in the book value of the reporting unit due to the Project's PPA being recorded as a financial instrument at fair value. The fair value accounting for the PPA and the impairment of goodwill have no impact on the underlying economic value of or anticipated future cash distributions from the Chambers Project. See Note 14(c) for additional details on the Chambers PPA.

7. Other intangible assets and transmission system rights

Other intangible assets include power purchase contracts 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 capacity of the Path 15 transmission line.

Amortization expense of $33,123 and $30,015 was recorded for the years ended December 31, 2008 and 2007, respectively.

	2008	2007
Transmission system rights	**$ 218,846**	$ 218,846
Power purchase agreements	**112,394**	70,232
Fuel supply agreements	**106,873**	77,518
Less accumulated amortization	**(54,094)**	(29,648)
	$ 384,019	$ 336,948

8. 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 and Rumford Cogeneration Company LP. 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:

	2008	2007
Long-term investments, beginning of year	**$ 64,815**	$ 76,973
Proceeds from disposal of Jamaica Project (Note 3(c))	**–**	(6,175)
Equity earnings (loss), net of impairment charges	**1,692**	(1,898)
Distributions received from equity investments	**(2,742)**	(4,085)
Long-term investments, end of year	**$ 63,765**	$ 64,815

9. Gas transportation contract liability

Prior to June 2007, Onondaga had certain long-term commitments for the provision of natural gas transportation service to the Onondaga Project through the year 2013. The contracts provided for fixed monthly demand charges, in addition to variable commodity charges based on the quantity of gas transported. Obligations related to the long-term gas transportation agreements were recognized as liabilities in purchase accounting upon the acquisition of Onondaga by the Company. These obligations were previously being amortized over the remaining lives of the contracts. In June 2007, Onondaga paid $9.75 million to an unrelated third party in exchange for the assumption by the third party of the obligations under the long-term gas transportation agreements. The carrying value of the transportation contract liability at the date of the transaction exceeded the amount paid by Onondaga to extinguish the liability, resulting in a gain of approximately $10 million in the second quarter of 2007. The gain was recorded in other project income in the consolidated statement of income (loss), comprehensive income (loss) and deficit. The Onondaga Project funded the transaction with a $9.75 million contribution from the Company, which was partially funded by a $9.4 million release of restricted cash at the Path 15 Project.

10. Credit facility

In August 2007, the Company amended its credit facility. Under the terms of the amendment, the total amount available under the credit facility was increased from $75 million to $100 million, of which $50 million may be utilized for letters of credit. The November 2008 maturity date of the credit facility has been extended to August 2012.

Outstanding amounts under the amended credit facility bear interest at the London Interbank Offered Rate ("LIBOR") plus an applicable margin that varies based on a credit ratio of a subsidiary of the Company. The range of applicable margin is 0.875% to 1.625%. Based on the credit statistics at December 31, 2008, the applicable margin is currently 0.875%. Prior to the amendment, the applicable margin was fixed at 1.50%.

As of December 31, 2008 and 2007, $36,442 and $23,307 was allocated, but not drawn, to support letters of credit for contractual credit support at several Projects. In March 2007, the Company borrowed $31,000 under the credit facility and used the proceeds to repay the acquisition credit facility related to the acquisition of Path 15. In September 2007, the outstanding amount on the credit facility was repaid with proceeds from the permanent financing arrangement for the Path 15 Project. In November 2008, the Company borrowed $55,000 under the credit facility and used the proceeds to partially fund the acquisition of Auburndale (Note 3(a)).

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 ratios and not on balance sheet ratios. The facility is secured by pledges of assets and interests in certain subsidiaries. The Company expects to be in compliance with its covenants for at least the next year.

11. 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 amortizes during the term of the respective revenue generating contracts of the Projects.

	2008	2007
Project debt, interest rates ranging from 2.06% to 9.5% maturing through 2028	$ 377,719	$ 381,097
Plus: purchase accounting fair value adjustments	17,564	19,758
Less: deferred financing costs	(6,616)	(7,741)
Less: current portion of Project debt	(24,512)	(36,926)
Long-term debt	$ 364,155	$ 356,188

Principal payments due under the terms of short-term and long-term debt in the next five years and thereafter are as follows:

2009 [1]	$ 79,512
2010	32,492
2011	34,143
2012	33,306
2013	32,228
Thereafter	221,038
	$ 432,719

1 Includes $55 million borrowing under the credit facility to partially fund the Auburndale acquisition. Under the terms of the credit facility, the Company has the option to extend the due date of this borrowing up to maturity of the credit facility in August 2012.

The Project 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, 2008, 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 joint ventures, except for the $55,000 outstanding balance with the credit facility as a result of the Auburndale acquisition. The Company has executed interest rate swaps to fix the interest rate on $40 million of this borrowing (Note 14(c)).

12. Subordinated Notes

	2008	2007
Subordinated Notes (Cdn$390,946; 2007 – Cdn$392,696)	**$ 320,974**	$ 397,459
Less deferred financing costs	**(10,390)**	(11,367)
	$ 310,584	$ 386,092

The Subordinated Notes will mature in November 2016 subject to redemption under specified conditions at the option of the Company, commencing on or after November 18, 2009 (Note 14(c)). Interest is payable monthly in arrears and the principal repayment will occur at maturity.

The Subordinated Notes are denominated in Canadian dollars and are secured by a subordinated pledge of the Company's interest in Holdings and certain subsidiaries, and contain certain restrictive covenants. Cdn$39,501 principal value of the Subordinated Notes are separately held by two investors and the remaining amount of the outstanding Subordinated Notes form a part of the Company's publicly traded IPSs.

Interest expense related to the Subordinated Notes was $40,169 and $40,818 for the years ended December 31, 2008 and 2007, respectively.

13. Convertible Debentures

On October 11, 2006, the Company issued Cdn$60,000 ($48,790, net of deferred financing costs, at December 31, 2008) aggregate principal amount of 6.25% Convertible Secured Debentures ("Debentures") for gross proceeds of $52,780. The Debentures pay interest semi-annually on April 30 and October 31 of each year. The Debentures mature on October 31, 2011 and are convertible into approximately 80.6452 IPSs per Cdn$1,000 principal amount of Debentures, at any time, at the option of the holder, representing a conversion price of Cdn$12.40 per IPS.

Interest expense was $3,490 and $3,532 for the years ended December 31, 2008 and 2007, respectively.

14. Financial instruments

A. CLASSIFICATION OF FINANCIAL INSTRUMENTS

The following table contains the carrying value and classification of the Company's financial instruments as of December 31, 2008 and 2007:

	2008	2007
Financial assets:		
Held for trading measured at fair value:		
Cash and cash equivalents	$ 50,071	$ 55,990
Restricted cash	25,372	38,304
Current portion of derivative instruments asset	15,001	23,753
Derivative instruments asset	109,482	79,611
Loans and receivables, measured at amortized cost:		
Accounts receivable	$ 48,128	$ 38,134
Income tax recoverable	2,300	10,261
Long-term deposits	664	–
Financial liabilities:		
Held for trading, measured at fair value:		
Current portion of derivative instruments liability	$ 10,031	$ 7,822
Derivative instruments liability	22,132	8,044
Other financial liabilities, measured at amortized cost:		
Accounts payable and accrued liabilities	$ 31,783	$ 32,886
Interest payable on Subordinated Notes and Convertible Debentures	3,455	4,271
Dividends payable	1,918	2,127
Current portion of long-term and short-term debt	79,512	36,926
Long-term debt	364,155	356,188
Subordinated Notes	310,584	386,092
Convertible Debentures	48,790	59,912

The fair value of financial assets and current financial liabilities which are measured at amortized cost approximate their carrying value because of the short-term nature of the instruments. The fair-value of long-term financial liabilities at December 31, 2008 was determined using quoted market prices, as well as 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 and are summarized below:

Long-term debt	$ 467,300
Subordinated Notes	264,739
Convertible Debentures	46,675

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:

	2008	2007
Change in fair value of derivative instruments		
Chambers power purchase agreement	$ 74,608	$ (106,113)
Onondaga indexed swap and hedge	(10,844)	(20,290)
Project-level interest rate swaps	(5,325)	(1,974)
Project-level natural gas swaps	(3,378)	–
	$ 55,061	$ (128,377)

C. DERIVATIVE INSTRUMENTS

The components of derivative instruments assets and liabilities as of December 31, 2008 and 2007 are set forth in the following table:

	2008	2007
Current portion of derivative instrument asset:		
Chambers power purchase agreement	$ 15,001	$ 5,607
Onondaga index swap hedge	–	17,689
Project-level interest rate swaps	–	457
	$ 15,001	$ 23,753
Derivative instruments asset		
Chambers power purchase agreement	$ 109,258	$ 44,045
Foreign currency forward contracts	–	35,566
Lake natural gas swaps	224	–
	$ 109,482	$ 79,611
Current portion of derivative instruments liability		
Lake natural gas swaps	$ 4,017	$ –
Auburndale natural gas swaps	4	–
Foreign currency forward contracts	744	–
Onondaga index swap and hedge	–	6,845
Interest rate swaps	5,266	977
	$ 10,031	$ 7,822
Derivative instruments liability		
Lake natural gas swaps	$ 595	$ –
Foreign currency forward contracts	12,998	–
Interest rate swaps	8,539	8,044
	$ 22,132	$ 8,044

Chambers Power Purchase Agreement

The power purchase agreement ("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 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, 2008, a 10% change in the projected average forward power prices through the term of PPA expiring in 2024 would change the fair value of the PPA by approximately $27 million.

Onondaga indexed swap and hedge

A swap agreement ("Indexed Swap") between a utility company and Onondaga, which had replaced Onondaga's original power purchase contract, expired on June 30, 2008. The Indexed Swap was a derivative financial instrument under which the utility company made monthly payments to Onondaga based upon the differential between an indexed contract price and a market reference price for electricity. The indexed contract price fluctuated in relation to the market cost of natural gas and a prescribed index of inflation. The notional quantity of electricity for the purpose of these calculations was fixed for the full term of the Indexed Swap.

In addition, Onondaga was party to a commodity derivative instrument ("Indexed Swap Hedge"), which locked in favourable gas, power and capacity pricing under the Indexed Swap. The Indexed Swap Hedge expired on June 30, 2008.

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 has the obligation to make distributions to shareholders predominantly in Canadian dollars. Since its inception, the Company has established a hedging strategy for the purpose of reinforcing the long-term sustainability of its distributions. The Company has executed this strategy by entering into forward contracts to purchase Canadian dollars at fixed rates of exchange sufficient to make monthly distributions through December 2013 at the current annual dividend level of Cdn$0.46 per common share, as well as interest payments on the Subordinated Notes and Debentures. It is the Company's intention to periodically consider extending the length of these forward contracts. Changes in the fair value of the Company's forward contracts partially offset foreign exchange gains or losses on the U.S. dollar equivalent of the Company's Canadian dollar obligations.

The following table summarizes the Company's forward foreign currency contracts with monthly settlement terms as of December 31, 2008:

	Notional monthly amounts		
Period	Sell U.S. dollars	Buy Cdn. dollars	Average rate
2009	4,974	6,000	1.2062
2010 - 2013	5,289	6,000	1.1344

In addition to the forward contracts in the table above that settle on a monthly basis, the Company has executed forward contracts to purchase Canadian dollars at fixed rates of exchange sufficient to make semi-annual payments on the Debentures. The contracts provide for the purchase of Cdn$1.9 million in April and in October of 2008 through 2011 at a rate of 1.1075 Canadian dollars per U.S. dollar.

The foreign exchange forward contracts are carried at estimated fair value based on quoted market prices. Changes in the fair value of the foreign currency forward contracts are reflected in foreign exchange loss (gain) in the consolidated statements of income (loss), comprehensive income (loss) and deficit.

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

	2008	2007
Unrealized foreign exchange gains (losses):		
Subordinated Notes and Convertible Debentures	$ 85,212	$ (68,419)
Forward contracts and other	(48,537)	30,703
	36,675	(37,716)
Realized foreign exchange gains on forward contract settlements	8,044	7,574
	$ 44,719	$ (30,142)

The following table illustrates the income (loss) that would be recorded on the Company's financial instruments in the event of a 10% hypothetical decrease in the value of the U.S. dollar compared to the Canadian dollar as of December 31, 2008:

Subordinated Notes	$ (32,097)
Convertible Debentures	(4,926)
Foreign currency forward contracts	33,874
	$ (3,149)

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 at a weighted average price of $12.24/Mmbtu.

These natural gas swaps are derivative financial instruments and were recorded in the consolidated balance sheet at fair value. 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 10-year PPA 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 natural gas prices 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 Company's fuel requirements through June 30, 2012. The remaining 20% is purchased at spot market prices and therefore the Project is exposed to changes in natural gas prices through the termination of the fuel supply agreement.

The Company is executing 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 are recorded in other comprehensive income (loss) as they have been designated as a hedge of the risk associated with changes in market prices of natural gas.

Subordinated notes prepayment option

The Company has 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 has determined that the redemption option is an embedded derivative that is recorded at fair value and periodic changes in fair value are recorded in other expenses in the consolidated statements of income (loss), comprehensive income (loss) and deficit. As of December 31, 2008, the fair value of the redemption option is zero.

Interest rate swaps

The Company's proportionately consolidated Mid-Georgia and Chambers Projects have executed interest rate swaps to economically fix a portion of the respective 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 as derivative instruments liability 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 (Note 10) and at its proportionately consolidated Auburndale Project to economically fix a portion of the their 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 existing credit facility as of November 2008. The interest rate swap termination date for Auburndale is November 30, 2009 and for the revolving credit facility is November 30, 2011.

The interest rate swap is a derivative financial instrument and is recorded in the balance sheet at fair value. Changes in the fair value of the interest rate swap are recorded in other comprehensive income (loss) as they have been designated as a hedge of the risks associated with the changes in the market interest rates.

D. AUCTION RATE SECURITIES

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

In February 2008, the overall market for ARSs suffered a significant decline in liquidity. Since early March 2008, most of the auctions of ARSs have been unsuccessful, resulting in the Company continuing to hold these securities and the issuers paying interest at the maximum contractual rate.

In September and November 2008, all of the Company's investments in ARS were sold at par plus accrued interest, for $36.5 million.

E. 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, 2008, 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.

F. OTHER FINANCIAL LIABILITIES

Convertible Debentures

The 6.25% Convertible Secured Debentures ("Debentures") are due October 31, 2011. Interest is payable semi-annually in arrears on April 30 and October 31 of each year. The Debentures are convertible into 80.6452 IPS per Cdn$1,000 principal amount of Debentures, at any time, at the option of the holder, representing a conversion price of Cdn$12.40 per IPS.

G. 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, establishing any new obligations in U.S. dollars instead of Canadian dollars. See Note 14(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.

The impact of 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, bears interest at fixed rates. Some of the non-recourse debt obligations at the Company's proportionately consolidated Auburndale, Mid-Georgia and Chambers projects bear interest at variable rates.

Exposure to changes in interest rates related to this variable rate debt has been mitigated through the use of interest rate swaps. See Note 14(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 $40.7 million at December 31, 2008. 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 are designed to mitigate the impacts to cash flows of changes in commodity prices by generally passing on 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 superior 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.

15. 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 maintaining a prudent capital structure whose risk characteristics 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, Subordinated Notes, Debentures and Common Stock.

The Company's IPSs each consist of one Common Share and Cdn$5.767 principal amount of Subordinated Notes. The Company currently pays monthly distributions at an annual rate of Cdn$1.094 per IPS, which consists of a dividend per common share of Cdn$0.46 per year and interest on the Subordinated Notes.

The Company has historically raised debt capital at the operating or Project-level at lower interest rates than what would be required for corporate-level debt. These financings are structured as non-recourse to the Company and an adverse impact to debt at any single Project has no influence on debt at other Projects, and in virtually all cases the principal fully amortizes before the primary power purchase agreement 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 a function of assessing the potential volatility of projected cash flows 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 resolving 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 equal bank participants. Acquisition bridge facilities have also historically been placed at this senior corporate level with the revolving credit facility lenders.

The capital structure is periodically reviewed by the Company's management and Board of Directors to determine whether changes are required to meet the objectives outlined above. The Company has 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. Management will periodically assess this option beginning in November 2009 and will consider exercising the call option if the Subordinated Notes can be recapitalized in a manner that benefits the Company's shareholders.

The Company is not required to repay Subordinated Notes before they become due in November 2016 and will exercise its call option only if alternatives exist to refinance the called debt on terms that benefit the Company on a long-term basis.

Examples of potentially positive alternatives could include: reduction of foreign currency risk by refinancing the Subordinated Notes with U.S. dollar-denominated debt; reducing interest expense by refinancing the Subordinated Notes at lower interest rates; and reducing the Company's overall debt by refinancing any or all of the Subordinated Notes by issuing equity. All of these options are subject to market conditions at the time the option is being considered.

There were no changes in the Company's approach to capital management during the period. Neither the Company nor any of its subsidiaries is subject to externally imposed capital requirements.

16. Income taxes

	2008	2007
Current income tax expense (benefit)	$ (12)	$ 3,974
Future tax expense (benefit)	12,535	(51,748)
	$ 12,523	$ (47,774)

The following is a reconciliation of income taxes calculated at the Canadian enacted statutory rate of 33.5% and 36.12% at December 31, 2008 and 2007, respectively, to the provision for income taxes in the consolidated statements of income (loss), comprehensive income (loss) and deficit:

	2008	2007
Computed income tax recovery at Canadian statutory rate	$ 41,276	$ (71,149)
Decrease resulting from:		
Operating countries with different income tax rates	8,009	(7,643)
	49,285	(78,792)
Valuation allowance	(39,840)	52,710
	9,445	(26,082)
Non-taxable foreign-source income	–	(475)
Permanent differences	4,367	(8,682)
Canadian loss carryforwards	(2,786)	(12,051)
Branch profits tax	2,368	993
Prior year true-up	(1,078)	(1,544)
Other	207	67
	3,078	(21,692)
Income tax expense (benefit)	$ 12,523	$ (47,774)

The tax effect of temporary differences that give rise to significant portions of the future tax assets and future tax liabilities at December 31, 2008 and 2007 are presented below:

	2008	2007
Future tax assets:		
Intangible assets	$ 18,888	$ 26,725
Loss carryforwards	41,512	38,152
Gas transportation contract and other accrued liabilities	16,182	9,889
Unrealized foreign exchange loss on Subordinated Notes	5,497	28,387
IPS issuance costs	540	3,199
Natural gas and interest rate hedges	2,136	–
Total future tax assets	84,755	106,352
Valuation allowance	(49,524)	(89,364)
	35,231	16,988
Future tax liabilities:		
Property, plant and equipment	(72,024)	(48,614)
Unrealized foreign exchange gain	(6,713)	(13,835)
Other	(1,377)	(1,453)
Total future tax liabilities	(80,114)	(63,902)
Net future tax asset (liability)	$ (44,883)	$ (46,914)

As of December 31, 2008, the Company had the following net operating loss carryforwards that are scheduled to expire in the following years:

2014	$ 5,258
2015	28,752
2026	29,786
2027	38,246
2028	34,929
	$ 136,971

These losses relate to the Canadian entity and may only be used to offset the future income of the Canadian entity for Canadian income tax purposes. At December 31, 2008, a full valuation allowance was taken against the future tax assets set up in respect of the Canadian entity's loss carryforwards as the Company believes that it is not more likely than not that the Canadian entity would be able to use any of these loss carryforwards.

17. Common Stock and normal course issuer bid

	Number of shares	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

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. 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, 2008, the Company had acquired 558,620 IPSs at an average price of Cdn$8.78 under the terms of the issuer bid. The issuer bid will terminate on July 24, 2009 or such earlier date that the Company has acquired the maximum number of IPSs under the issuer bid. Atlantic Power will pay 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 will be canceled.

The purchase price in excess of the average book value of the shares in the amount of $275 has been allocated to deficit.

18. Long-term incentive plan

On March 26, 2008 and March 28, 2007, the Board of Directors approved grants of notional units to acquire a maximum of 142,717 and 172,071 IPSs, respectively, under the terms of the LTIP. The weighted average fair value per notional unit granted was Cdn$10.18 and Cdn$10.93 for 2008 and 2007, respectively. The measurement date for the awards for accounting purposes occurred when participants were informed of the details of their awards in April 2008 and April 2007, respectively. As a result, compensation expense related to the LTIP was recorded in the amounts of $770 and $970 for the years ended December 31, 2008 and 2007, respectively.

19. Basic and diluted earnings (loss) per share

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

	2008	2007
Basic IPSs outstanding	61,290	61,471
Dilutive potential IPSs:		
Convertible Debentures	4,839	–
LTIP notional units	221	–
Fully diluted IPSs	66,350	61,471

Diluted earnings (loss) per share is computed including dilutive potential IPSs as if they were outstanding IPSs during the year. Dilutive potential IPSs include IPSs that would be issued if all of the convertible debentures were converted into IPSs at January 1, 2008. Dilutive potential IPSs also include the weighted average number of IPSs, 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 IPSs under the terms of the LTIP.

Because the Company reported a loss during the year ended December 31, 2007, the effect of including potentially dilutive shares in the calculation during those periods is anti-dilutive.

20. Accumulated other comprehensive loss

The components of accumulated other comprehensive loss are as follows:

	2008	2007
Cumulative unrealized loss on natural gas hedges	$ (4,393)	$ –
Cumulative unrealized loss on interest rate swaps	(947)	–
Future tax benefit	2,136	–
	$ (3,204)	$ –

21. Related party transactions

In connection with the Company's initial public offering, ArcLight Energy Partners Funds I, L.P. ("Fund I") and ArcLight Energy Partners Funds II, L.P. ("Fund II", and, together with Fund I, the "ArcLight Funds") and Caithness Energy, LLC ("Caithness") (together with the ArcLight Funds, the "Former Investors") acquired the right to request, at any time, that Holdings purchase for cancellation all or any portion of the Former Investors' interests in Holdings, subject to a minimum remaining 10% interest for a two-year period from November 18, 2004. This liquidity right was treated as a liability of the Company and recorded at fair value on the consolidated balance sheets. Any change in the non-controlling interest liability was recognized in the consolidated statements of income (loss), comprehensive income (loss) and deficit as a change in non-controlling interest liability.

The Former Investors have exercised the liquidity right in a series of transactions since the initial public offering through February 2007 as follows:

	Amount paid to former Investors	Incremental share acquired(i)	Former Investors' remaining share
October 2005	$ 64,374	12.0%	29.9%
October 2006	87,287	15.5%	14.4%
February 2007	76,888	14.4%	0.0%

(i) Represents incremental portion of Holdings purchased by the Company from the Former Investors in the transaction.

The amounts paid to the Former Investors in the transactions above were financed by the Company through the sale of IPSs and Convertible Debentures.

At January 1, 2007, $74,433 of restricted cash included in the consolidated balance sheet was held in escrow pending regulatory approval of a transaction whereby the remaining interests of the Former Investors were acquired by Holdings. In February 2007, the required regulatory approval was obtained and the transaction was completed. Holdings is now a wholly-owned subsidiary of the Company and the liquidity right of the Former Investors has been extinguished.

During the year ended December 31, 2008, in accordance with the management agreement between the Company and Atlantic Power Management, LLC (that is owned by the ArcLight Funds), the Company incurred management and incentive fees of $356 and $864, respectively. During the year ended December 31, 2007, the Company incurred management and incentive fees of $344 and $869, respectively.

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

22. 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, 2008 which are expected to have a material impact on the Company's financial position or results of operations.

23. Subsequent events

On March 23, 2009, Path 15, FERC staff, and the intervenors in the Project's rate case for the 2008-10 period filed an uncontested settlement with the FERC. The Company expects the FERC to approve the settlement in the next two to three months. Management does not expect the settlement to have a significant impact on the financial position or results of operations of the Company.

24. Comparative figures

Certain 2007 figures have been reclassified to conform to the financial statement presentation adopted in 2008.

Atlantic Power Corporation

Exchange Listing
IPSs Issued and Outstanding: 60,940,731
Ticker Symbol: ATP.UN

Cdn$60 million 6.25% Convertible Debentures
due October 31, 2011
Ticker Symbol: ATP.DB

Exchange: TSX

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Atlantic Power Corporation Directors

Irving Gerstein
Chairman of the Board
Toronto, Ontario
Senator Gerstein is a retired executive and is currently a Director of Medical Facilities Corporation, Economic Investment Trust Limited and Student Transportation of America.

Ken Hartwick
Chairman of the Audit Committee
Toronto, Ontario
Mr. Hartwick is President and CEO of Ontario Energy Savings Corp., which is a wholly-owned subsidiary of, and provides administrative services to, Energy Savings Income Fund, an income trust 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 Management, LLC.

Bill Whitman
Ridgewood, New Jersey
Mr. Whitman is currently an independent consultant advising and representing clients on energy-from-waste matters.

Directors
from left to right:
Barry Welch,
John McNeil,
Irving Gerstein,
Bill Whitman
and Ken Hartwick

Atlantic Power Management

Barry Welch
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Executive Officer

Patrick Welch
Chief Financial Officer and
Corporate Secretary

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