PUBLIC VERSION

IN THE MATTER OF AN ARBITRATION UNDER CHAPTER 11 OF THE NORTH AMERICA FREE TRADE AGREEMENT AND THE UNCITRAL ARBITRATION RULES

Between

Mesa Power Group, LLC
(the "Investor")

And

Government of Canada
("Canada")

EXPERT WITNESS REPORT OF
Richard Taylor and Robert Low

Privileged

Dated: November 18, 2013

Deloitte LLP
181 Bay Street
Brookfield Place, Suite 1400
Toronto ON M5J 2V1
Canada

Tel: 416-601-6690
www.deloitte.ca

November 18, 2013

Appleton & Associates International Lawyers
77 Bloor Street West, 18th Floor,
Toronto ON M5S 1M2

Attention: Mr. Barry Appleton, Managing Partner

Dear Sir:

Subject: Mesa Power Group, LLC v. Government of Canada

Deloitte LLP ("Deloitte") has been retained, as professional advisors, by Appleton & Associates International Lawyers ("Counsel") in connection with Counsel's representation of Mesa Power Group, LLC (the "Company" or "Mesa Power") in respect of the above-noted mater.

We have been asked by Counsel to prepare an expert's report quantifying the estimated economic losses (the "Economic Losses") suffered by the Company as a result of the alleged actions of the Government of Canada ("Canada") as at November 25, 2009, January 21, 2010 and May 29, 2010[1] (collectively, the "Valuation Dates").

Our report has been prepared in conformity with the Practice Standards of The Canadian Institute of Chartered Business Valuators (the "CICBV") for an Expert Report[2]. No part of Deloitte's fee is contingent upon the conclusions reached in our report or any action or event contemplated in, or resulting from the use of, the report. The principal experts and other staff involved in the preparation of the report acted independently and objectively in completing this engagement.

Purpose

We understand that Mesa Power has filed a Notice of Intent to Submit a Claim to Arbitration, dated July 6, 2011, followed by a Notice of Arbitration, dated October 4, 2011, pursuant to the provisions of the North American Free Trade Agreement (the "NAFTA"). The purpose of this report is to quantify the Economic Losses, if any, suffered by Mesa Power as a result of the alleged actions of Canada.

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[1] As further discussed in the report, the Valuation Dates differ based on the alleged breaches of the North American Free Trade Agreement.
[2] As defined in Standard 310 of the Practice Standards of the CICBV.

Currency of report

Unless otherwise noted, all monetary amounts shown in this report and attached schedules are expressed in Canadian dollars ("C$"). Translation of monetary amounts expressed in other currencies, if any, has been made at the rate of exchange prevailing on the each of the Valuation Dates.

Restrictions

In accordance with our engagement agreement, this report is not intended for general circulation or publication, nor is it to be reproduced or used for any purpose other than that outlined above without the prior written consent of Deloitte in each specific instance. We do not assume any responsibility or liability for losses incurred by any party as a result of the circulation, publication, reproduction, or use of this report contrary to the provisions in this paragraph. Without limiting the generality of the foregoing, our report, or any references thereto or summaries thereof or any other oral or written opinions or advice of Deloitte including the contents of any oral or written presentations by us in connection with this engagement and references to us or any material provided by us, shall not be used, published or distributed in whole or in part in any way or to any other person without our prior written consent.

We reserve the right to review all calculations included or referred to in our analysis and, if we consider it necessary, to revise our conclusion in light of any information which becomes known to us after the date of this report.

We offer no guarantee or warranty that the conclusion as determined by us will be accepted by any third parties, such as tax authorities, tribunals, securities regulators or auditors. Accordingly, we can accept no responsibility for any adverse consequences that may arise in the event a different conclusion is ultimately agreed with any third parties.

We believe that our analyses must be considered as a whole and that selecting portions of the analyses or the factors considered by us, without considering all factors and analyses together could create a misleading view of the process underlying the analysis. The preparation of an expert report is a complex process and is not necessarily susceptible to partial analysis or summary description. Any attempt to do so could lead to undue emphasis on any particular factor or analysis.

Summary of findings

Based on the scope of our review (Appendix A), our research, analysis, experience, restrictions and assumptions (Appendix B and noted elsewhere in the attached report), in our opinion, the Economic Losses as a result of the alleged actions of Canada are set out in the table below as at the Valuation Dates[3]. If requested to select a single point estimate of the Economic Losses, we would suggest the midpoint of the range of $624.1 million to $683.2 million (NAFTA Articles 1102/1103/1105), or $653.7 million, set out below. The Economic Losses related to Article 1106 while separately determined as $101.2 million to $111.3 million, with a midpoint of $106.3 million, are included in the Economic Losses for Articles 1102, 1103 and 1105, and are not

[3] As noted above, the alleged breaches occurred on different dates. Further to this, as detailed in our report, there are different dates on which the alleged breaches occurred for each of Mesa Power's wind projects.

additive thereto. The Economic Losses presented herein exclude any consideration for pre-judgment and post-judgment interest, as well as any legal or other fees incurred by the Plaintiffs in this matter.

CAD 000s	Low	High
NAFTA 1102/1103/1105		
Base Case	303,000	345,000
Economic Development Adder	20,000	22,000
Capacity Expansion	33,000	38,000
Economic Development Adder applicable to Capacity Expansion	2,000	2,000
Past costs incurred	8,100	8,100
General Electric deposit forfeited	156,833	156,833
NAFTA 1106 (below)	101,200	111,300
Total NAFTA 1102/1103/1105	**624,133**	**683,233**
NAFTA 1106		
Base Case	91,000	100,000
Economic Development Adder	1,000	1,000
Capacity Expansion	9,000	10,000
Economic Development Adder applicable to Capacity Expansion	200	300
Total NAFTA 1106	**101,200**	**111,300**

Should you have any questions concerning our analysis or report, please contact Richard Taylor at 416-775-7499 or Robert Low at 416-775-7425.

Yours truly,

Deloitte LLP

Richard Taylor
Partner
Financial Advisory

Robert Low
Executive Advisor
Financial Advisory

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1 Overview

Summary of dispute

Mesa Power's FIT program application process

1.1 Mesa Power LLC ("Mesa Power" or the "Company") applied to the Ontario Power Authority's ("OPA") Feed-in Tariff ("FIT") program on November 25, 2009 for two of its wind energy projects, Arran ("Arran") and Twenty-Two Degrees ("TTD"), located in the Municipality of Central Huron and Municipality of Arran-Elderslie in the Province of Ontario[4], respectively. Mesa Power then applied for FIT contracts ("FIT Contracts") on May 29, 2010 for its remaining two wind energy projects, Summerhill and North Bruce (together with Arran and TTD referred to as the "Projects"), located in the Municipality of Kincardine, Town of Saugeen Shores, and the Municipality of Central Huron in the Province of Ontario, respectively.[5]

1.2 Initial FIT project rankings were issued in December 2010. In those rankings, two of Mesa Power's projects – TTD and Arran – were ranked eighth and ninth, respectively, of the 26 projects within the eligible capacity for the Bruce Region of 750 megawatts ("MW").[6] A representative from Mesa Power wrote to the OPA requesting more information regarding the review process; however, the OPA did not disclose the ranking methodology and confirmed the ranking of the Arran and TTD projects.[7]

1.3 On June 3, 2011, the OPA issued a new set of rules with respect to awarding FIT program contracts (the "New Rules")[8]. The New Rules included four significant changes, among other things:

a) The OPA was then able to award 750 MW of contracts in the Bruce Region transmission zone and 300 MW of contracts in the West of London Region transmission zone;

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[4] Investor's Schedule of Exhibits **C0364** (001810),Investor's Schedule of Exh bits **C0365** (001816-1.1.1), Investor's Schedule of Exhibits **C0366** (001817-1.1.2), Investor's Schedule of Exhibits **C0367** (001818-1.1.3), Investor's Schedule of Exhibits **C0368** (001819-1.1.4), Investor's Schedule of Exh bits **C0369** (001820-1.1.5)

[5] Investor's Schedule of Exhibits **C0364** (001810), Investor's Schedule of Exhibits **C0365** (001816-1.1.1), Investor's Schedule of Exhibits **C0366** (001817-1.1.2), Investor's Schedule of Exhibits **C0367** (001818-1.1.3), Investor's Schedule of Exhibits **C0368** (001819-1.1.4), Investor's Schedule of Exh bits **C0369** (001820-1.1.5)

[6] Investor's Schedule of Exhibits **C0350** (004352) FIT website: http://www.fit.powerauthority.on.ca/Storage/102/11184_Launch_Project_Information_-_Dec_21_2010.pdf

[7] Notice of Intent to Submit a Claim to Arbitration, Mesa Power Group, LLC v. Government of Canada.

[8] Investor's Schedule of Exhibits **C0340** (004342) Ontario Power Authority Feed-In Tariff Program, FIT Rules Version 1.5, June 3, 2011

b) All projects were given a five day opportunity period to change their interconnect point starting Monday June 6, 2011;

c) Projects in the Bruce or West of London Region were able to change or select interconnect points outside their own region; and

d) Projects were then to be evaluated using a provincial wide ranking.

1.4 As a result of the New Rules, projects in the West London Region that had higher provincial rankings than those ranked in the Bruce Region were able change their interconnect to the Bruce Region and therefore could be eligible for FIT contracts in that region. Given the additional projects that moved to the Bruce Region, projects that were initially ranked within the top 750 MW moved below the eligible capacity. As a result, TTD and Arran were re-ranked 14th and 15th, respectively. The projects that were ranked higher had a larger capacity and therefore TTD and Arran were no longer in the 750 MW capacity constraints for the region.

1.5 On July 4, 2011, Mesa Power was notified by the OPA that the rankings of its wind farm investments had been lowered and would not be offered FIT Contracts in the Bruce Region.[9]

1.6 As part of the development of the Projects, Mesa Power paid a deposit of [redacted] o General Electric Company ("GE") for the purchase of wind turbines.[11] Given that Mesa Power did not receive the FIT Contracts, the order for [redacted] turbines was terminated on [redacted] by Mesa Power, resulting in a forfeiture of a portion of this deposit, in the amount of [redacted] [2].The contract was amended as Mesa Power attempted to mitigate its losses by using the turbines for another project. Mesa Power's mitigation efforts were unsuccessful and therefore it terminated the contract with GE and the remaining portion of the deposit of [redacted] was forfeited on [redacted][13]

Agreement between Samsung C&T Corporation, Korea Electric Power Corporation and the Government of Ontario

1.7 On January 21, 2010, Samsung C&T Corporation ("Samsung"), a Korean-based company, and Korea Electric Power Corporation (together, the "Korean Consortium") signed the Green Energy Investment Agreement ("GEIA"), valued at $7 billion, with the government of Ontario, represented by Ontario's Premier and Ontario's Minister of Energy[14]. Based on our understanding, this agreement resulted in the Korean Consortium's access to supply renewable energy under undisclosed terms including a guaranteed total of 2,500 MW of capacity in Ontario.[15] Of this amount, 2,000 MW of capacity was designated as wind

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[9] Notice of Intent to Submit a Claim to Arbitration, Mesa Power Group, LLC v. Government of Canada, dated July 6, 2011.
[10] This amount was approximately [redacted] as at the date of the invoice on [redacted]
[11] Investor's Schedule of Exhibits **C0381** (002111) GE Invoice June 15 2008.
[12] Investor's Schedule of Exhibits **C0383** (002438) GE Termination Lette [redacted]
[13] Investor's Schedule of Exhibits **C0382** (002437) Letter from Mesa Power to GE dated December 21, 2012.
[14] Notice of Intent to Submit a Claim to Arbitration, Mesa Power Group, LLC v. Government of Canada (par. 10), dated July 6, 2011.
[15] Investor's Schedule of Exhibits **C0322** (PH 765) Green Energy Investment Agreement January 21, 2010 (page 2).

generation capacity to be carried out in five phases, with each phase targeting 400 MW of production[16].

1.8 In addition to the guaranteed capacity of 2,500 MW, the Korean Consortium had the ability to increase or decrease the capacity by 10% or by 20%. In order to increase or decrease capacity by 10%, Samsung would have had to provide reasonable notice to Ontario. However, in order to increase or decrease capacity by 20%, a negotiation was required to take place between Samsung and Ontario[17].

1.9 Under the terms of the GEIA, the Korean Consortium would also receive an increase in the FIT Contract price ("Economic Development Adder") of $0.50 per kilowatt hour ("kWh"). The Economic Development Adder would be adjusted if the Korean Consortium did not meet the deadlines defined in the GEIA.

1.10 Pursuant to the GEIA, the Government of Ontario was required to facilitate the necessary regulatory approvals and permits.[18]

1.11 On July 28, 2011, the Korean Consortium signed an amended agreement to the GEIA ("Amended GEIA") which delayed the targeted commercial operating dates for the five phases specified in the GEIA by one year, approximately two years and eight months after the date of the Amended GEIA. Under the Amended GEIA, the Economic Development Adder that the Korean Consortium would receive decreased to $0.27 per kWh[19] to a maximum net present value benefit of $110 million. As a result of the Amended GEIA, the Economic Development Adder was now only available for the first two phases of the Korean Consortium's projects and would be adjusted on a pro rata basis based on the number of new manufacturing jobs created by the Korean Consortium. Although it appears consideration was required to receive the Economic Development Adder, we understand based on discussions with counsel, the arrangement could not be enforceable as it is a breach under Article 1106 (paragraph 1) of the NAFTA. Similar to the GEIA, the Amended GEIA was initially not a public document and Mesa Power was not aware of its contents except through the course of this litigation.

The Claims

1.12 In response to the actions and circumstances set out above, on July 6, 2011, Mesa Power submitted a Notice of Intent to file a claim to Arbitration against Canada alleging a breach of Section B of Chapter 11 of the North American Free Trade Agreement ("NAFTA"). In particular, Mesa Power alleges that Canada

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[16] Investor's Schedule of Exhibits **C0322** (PH 765) Green Energy Investment Agreement January 21, 2010 (article 3.2).
[17] Investor's Schedule of Exhibits **C0322** (PH 765) Green Energy Investment Agreement January 21, 2010 (article 3.4).
[18] Investor's Schedule of Exhibits **C0322** (PH 765) Green Energy Investment Agreement January 21, 2010 (article 7.3a).
[19] Investor's Schedule of Exhibits **C0282** Green Energy Investment Agreement – Amending Agreement July 29, 2011.

violated at least the following sections of the NAFTA: Articles 1102, 1103, 1104[20], 1105, 1106, and 1503(2)[21].

1.13 On October 4, 2011, Mesa Power then submitted a Notice of Arbitration under the rules of the United Nations Commission on International Trade Law and NAFTA. We have described the claims and the related economic losses (the "Economic Losses") under each of the NAFTA articles below.

Article 1102 – National Treatment & Article 1103 – Most-Favoured-Nation Treatment

1.14 Article 1102 states each party shall accord to investors of another party treatment no less favorable than that it accords, in like circumstances, to its own investors with respect to the establishment, acquisition, expansion, management, conduct, operation, and sale or other disposition of investments.

1.15 Article 1103 states that each party shall accord to investments of investors of another party treatment no less favorable than that it accords, in like circumstances, to investments of investors of any other Party or of a non-Party with respect to the establishment, acquisition, expansion, management, conduct, operation, and sale or other disposition of investments.

1.16 Mesa Power claims that Canada failed to meet its obligations under Article 1102 and 1103 when it provided more favourable transmission treatment to a Canadian company in like circumstances, Boulevard Associates Canada, Inc[22]., and the Korean Consortium. Specifically, Mesa Power claims that:

a) the GEIA signed between the Korean Consortium and Ontario's Premier and Ontario's Minister of Energy granted the Korean Consortium guaranteed priority access to supply renewable energy to the Province of Ontario's energy grid that was not available to other energy providers in the province;

b) The Korean Consortium received a guaranteed right of first refusal on transmission access in certain transmission zones in the Province of Ontario including 500 MW in the Haldimand, Essex and Chatham-Kent transmission zone and 500 MW in the Bruce Region of Ontario. No other company was granted such favourable treatment. This prevented Mesa from receiving an allocation of the capacity in those regions;

c) the change in rules to the FIT program on June 3, 2011 allowed projects in the Bruce or West of London Regions to change and select an interconnect point outside their own region. Mesa Power claims that the change in rules allowed projects in the West of London Region, such as projects of competitors in like circumstances to Mesa Power, Boulevard Associates

[20] We have not been requested to quantify separate Economic Losses, if any, for this claim.

[21] The claim under 1503(2) states that Canada failed to ensure through regulatory control, administrative supervision or the application of other measures, that the OPA acted in a manner consistent with Canada's obligation under NAFTA Chapter Eleven, wherever the OPA exercised regulatory, administrative or other governmental authority. We have not been requested to quantify separate Economic Losses, if any, for this claim.

[22] Boulevard Associates Canada, Inc. was able to bring four of its West of London region projects over to the Bruce Region due to the rule changes on July 3, 2011.

Canada, Inc., to build long transmission lines to interconnect in the Bruce Region and move ahead in the priority ranking;

d) As discussed above, in the GEIA and Amended GEIA, the Korean Consortium was offered an Economic Development Adder which gave the Korean Consortium more favourable treatment than other investors;[23] and,

e) Also discussed above, in the GEIA, the Korean Consortium was offered the ability to increase the capacity of its Projects by 10% and possibly 20% which gave the Korean Consortium more favourable treatment than other investors.[24]

1.17 Based on the above, and our understanding of the requirements of these Articles, the Economic Losses related to Articles 1102 and 1103 include:

a) the lost profits that Mesa Power would have earned from its projects, had a FIT Contract been obtained; and

b) the lost revenues that Mesa Power would have earned from its projects had the Company been offered an Economic Development Adder, which was offered to the Korean Consortium;

c) the lost profits that Mesa Power would have earned from its Projects had the Company been able to increase the capacity of each Project by 10%;

d) the costs incurred in relation to the forfeiture of the deposit paid by Mesa Power to GE for the purchase of wind turbines;

e) the costs incurred by Mesa Power in relation to preparing the projects for commercial operation. Although these costs would have been incurred to achieve profits, we have added the past costs to the losses determined in 1102 and 1103 as they have been deducted in determining the lost profits in a) above and they were incurred by Mesa Power and therefore cannot be avoided; and

f) the lost profits related to Article 1106 – Performance Requirements as we understand that the Domestic Content Requirements were in violation of Article 1102 – National Treatment. Further, by virtue of Article 1104, the Domestic Content Requirements were also in violation of Article 1103 – Most-Favoured-Nation Treatment. Article 1106 and the losses related thereto are described below.

1.18 We have assumed that the dates for measurement of the losses (collectively the "Valuation Dates" or the "Valuation Date") for the claim related to Articles 1102 and 1103 are:

a) TTD and Arran: January 21, 2010, the date the GEIA was signed as at this point TTD and Arran had applied for FIT contracts;

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[23] This is not specifically categorized as a claim in the Notice of Intent as the terms of the GEIA were not known at the time the claim was filed.

[24] This is not specifically categorized as a claim in the Notice of Intent as the terms of the GEIA were not known at the time the claim was filed.

b) North Bruce and Summerhill: May 29, 2010, the date that Mesa Power submitted FIT contracts for these Projects.

Article 1106 – Performance Requirements

1.19 Article 1106 (1) states the following. No Party may impose or enforce any of the following requirements, or enforce any commitment or undertaking, in connection with the establishment, acquisition, expansion, management, conduct or operation of an investment of an investor of a Party or of a non-Party in its territory:

a) to export a given level or percentage of goods or services;

b) to achieve a given level or percentage of domestic content;

c) to purchase, use or accord a preference to goods produced or services provided in its territory, or to purchase goods or services from persons in its territory;

d) to relate in any way the volume or value of imports to the volume or value of exports or to the amount of foreign exchange inflows associated with such investment;

e) to restrict sales of goods or services in its territory that such investment produces or provides by relating such sales in any way to the volume or value of its exports or foreign exchange earnings;

f) to transfer technology, a production process or other proprietary knowledge to a person in its territory, except when the requirement is imposed or the commitment or undertaking is enforced by a court, administrative tribunal or competition authority to remedy an alleged violation of competition laws or to act in a manner not inconsistent with other provisions of this Agreement; or

g) to act as the exclusive supplier of the goods it produces or services it provides to a specific region or world market.

1.20 Mesa Power claims that Canada failed to meet its obligations under Article 1106 due to establishing Canadian and Ontario content requirements and “buy local” performance requirements (the “Domestic Content Requirements”) as a pre-condition to obtain approval of commercial contracts under the FIT program.

1.21 Based on the above, and our understanding of the requirements of this article, the Economic Losses related to Article 1106 include:

a) the reduced capital costs to construct the Projects, had no Domestic Content Requirements were in place;

b) the lost profits (including decreased operating costs) that Mesa Power would have earned from its Projects, had no Domestic Content Requirements were in place;

c) the incremental profits related to the Economic Development Adder; and

d) the incremental profits related to the 10% increase in capacity for each of the Projects as offered to the Korean Consortium as part of the GEIA.

1.22 We have assumed the Valuation Dates for the claim related to Article 1106 are:

a) TTD and Arran: The Domestic Content Requirements were announced on September 24, 2009, but not imposed on Mesa until the FIT Applications were submitted as Mesa is required to be involved in the FIT program in order to have the Domestic Content Requirements imposed. The Valuation Date would be November 25, 2009, the date the FIT Applications for TTD and Arran were submitted;

b) North Bruce and Summerhill: Consistent with the selection of the Valuation Date for TTD and Arran, the Valuation Date for North Bruce and Summerhill would be May 29, 2010, the FIT Application date.

1.23 While we have separately quantified the Economic Losses related to Article 1106, these are included in the Economic Losses related to Articles 1102, 1103 and 1105 and accordingly are not additive thereto.

Article 1105 – Minimum Standard of Treatment

1.24 Article 1105 states each party shall accord to investments of investors of another party treatment in accordance with international law, including fair and equitable treatment and full protection and security.

1.25 Mesa Power claims that Canada failed to meet its obligations under Article 1105 by:

a) directing the OPA to change the rules for awarding Wind Power Purchase Agreement contracts (FIT Contracts) under the FIT program, resulting in the OPA ignoring the technical merits of the Company's wind farms and relying on political considerations in the awarding of contracts;

b) failing to treat Mesa Power fairly by changing the rules governing territorial limits for interconnection arbitrarily, without transparency, and without notice and due process;

c) the economic connection test was delayed and then abandoned discriminatorily, arbitrarily and without transparency;

d) establishing the Domestic Content Requirements as a pre-condition to obtain approval of commercial contracts under the FIT program; and

e) entering into the GEIA signed between the Korean Consortium and Ontario's Premier and Ontario's Minister of Energy which granted the Korean Consortium guaranteed priority access to supply renewable energy to the Province of Ontario's energy grid relative to what was available to other energy providers in the province.

1.26 Based on the above, and our understanding of the requirements of this Article, the Economic Losses related to Article 1105 include all of the heads of economic losses set out above. As a result, the Economic Losses for Article 1105 are equal to the Economic Losses for Articles 1102 and 1103, which include the Economic Losses related to Article 1106.

1.27 We have assumed the Valuation Dates for the claim related to Article 1105 are consistent with the assumptions used to quantify the Economic Losses of 1102, 1103 and 1106.

Purpose of report

1.28 The purpose of the report is to provide Counsel with an expert's report quantifying the Economic Losses suffered by Mesa Power, as a result of the alleged actions of Canada. We understand that our report will be used to assist the Tribunal responsible for hearing this matter.

Summary of conclusions

1.29 Based on the scope of our review (Appendix A), assumptions (Appendix B) and our research, analysis and experience, our opinion of the Economic Losses, as set out in further detail in Section 4, are summarized in the table below. If requested to select a point of Economic Losses, we would suggest the midpoint of the range of $624.1 million to $683.2 million (NAFTA 1102/1103/1105), or $653.7 million, set out below. The Economic Losses related to Article 1106 while separately determined as $101.2 million to $111.3 million, with a midpoint of $106.3 million, are included in the Economic Losses for Articles 1102, 1103 and 1105, and are not additive thereto. The Economic Losses presented herein exclude any consideration for pre-judgment and post-judgment interest, as well as any legal or other fees incurred by the Plaintiffs in this matter.

CAD 000s	Low	High
NAFTA 1102/1103/1105		
Base Case	303,000	345,000
Economic Development Adder	20,000	22,000
Capacity Expansion	33,000	38,000
Economic Development Adder applicable to Capacity Expansion	2,000	2,000
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General Electric deposit forfeited	156,833	156,833
NAFTA 1106 (below)	101,200	111,300
Total NAFTA 1102/1103/1105	**624,133**	**683,233**
NAFTA 1106		
Base Case	91,000	100,000
Economic Development Adder	1,000	1,000
Capacity Expansion	9,000	10,000
Economic Development Adder applicable to Capacity Expansion	200	300
Total NAFTA 1106	**101,200**	**111,300**

2 Company and project description

Company description

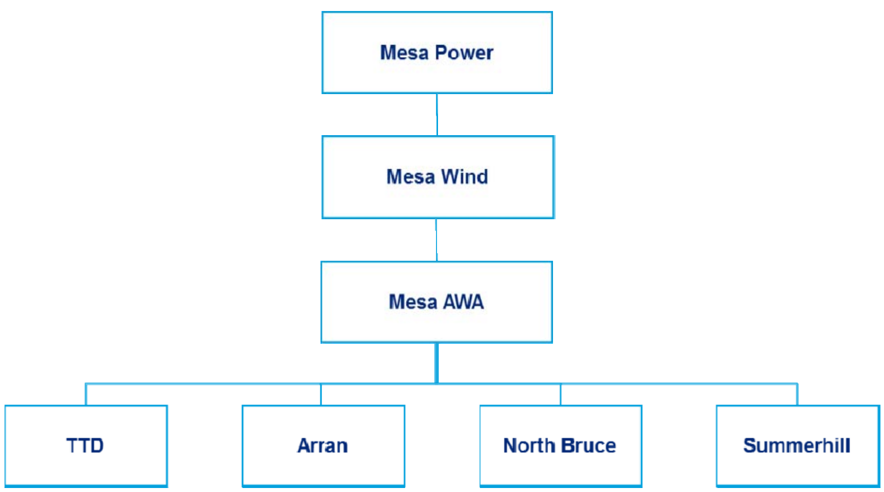
2.1 Mesa Power, a Delaware limited liability corporation was created by T. Boone Pickens in 2007 and is based in Dallas Texas. The Company develops and finances renewable energy power projects including wind.[25] Mesa Power owns Mesa Wind LLC ("Mesa Wind") which controls Mesa AWA LLC ("Mesa AWA"). Mesa AWA owns and controls the following wind farms projects (the "Projects") in Southwestern Ontario:

a) TTD Wind Project ULC ("TTD"), a 150 MW wind project located in the Municipality of Central Huron;

b) Arran Project ULC ("Arran"), a 115 MW wind project located in the Municipality of Arran-Elderslie and the Town of Saugeen Shores;

c) North Bruce Project ULC ("North Bruce"), a 200 MW wind project located in Kincardine in the town of Saugeen Shores; and

d) Summerhill Project ULC ('Summerhill"), a 100 MW wind project located in the Municipality of Central Huron.[26]



2.2 The following provides an overview of the FIT program and the Projects.

[25] Mesa Power website.
[26] Notice of Intent to Submit a Claim to Arbitration, Mesa Power Group, LLC v. Government of Canada, dated July 6, 2011.

OPA and the FIT program

2.3 The FIT program was enabled by the Green Energy and Green Economy Act, 2009 and was implemented by the OPA. Ontario's FIT program provides standard pricing for renewable electricity production sources including solar, wind, water and bioenergy. The prices are expected to cover costs and a reasonable return on investment. The different renewable fuel sources, such as solar, waterpower, wind and biogas each have different pricing structures.[27] One of the requirements for the FIT program is the Domestic Content Requirements. For wind projects over 10 kilowatts ("kW"), the minimum Domestic Content Requirements are as follows:

a) Minimum 25% for projects with milestone date for commercial operation from 2009 to 2011; and

b) Minimum 50% for projects with milestone dates for commercial operation in 2012 and later.[28]

2.4 Based on the May 24, 2013 World Trade Organization ruling, the Domestic Content Requirements specified for the FIT program were lowered resulting in a minimum domestic content level of 20% for onshore wind facilities, and for FIT contracts awarded in the fall 2013 window for Small FIT, microFIT and pilot solar projects on unconstructed buildings.[29]

2.5 The Proposed FIT price schedule presentation, dated April 2009 and prepared by the OPA, outlines the initial valuation assumptions used to determine the pricing structure for the renewable energy projects. The costs included in the analysis are capital costs, operating, maintenance and connection costs at an assumed contract term of 20 years (40 years for waterpower projects). The financing structure expectations include an after-tax return on equity of 11%.[30]

2.6 Throughout the duration of the program, the OPA is required to review the pricing structure to adjust the prices. According to the FIT program Two-Year Review Report, the evolving global market has contributed to project cost reductions resulting in lower prices.[31] The FIT pricing schedule version two was implemented April 5, 2012 resulting in a decline in wind prices from 13.532 cents per kilowatt hour to 11.533 cents per kilowatt hour for new FIT contracts.

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[27] Investor's Schedule of Exhibits **C0351** (004353) Feed-In Tariff (FIT) Program, Program Overview, http://fit.powerauthority.on.ca/sites/default/files/page/FIT_Program_Overview_Version_2.pdf

[28] Investor's Schedule of Exhibits **C0351** (004353) Feed-In Tariff (FIT) Program, Program Overview, http://fit.powerauthority.on.ca/sites/default/files/page/FIT_Program_Overview_Version_2.pdf

[29] Investor's Schedule of Exhibits **C0352** (004354) Letter to Mr. Colin Andersen RE: Administrative Matters Related to Renewable Energy and Conservation Programs, August 16, 2013, http://powerauthority.on.ca/sites/default/files/page/DirectionAdministrativeMatters-renewables-Aug16-2013.pdf

[30] Investor's Schedule of Exhibits **C0353** (004355) Proposed Feed-in Tariff Price Schedule, Stakeholder Engagement – Session 4, April 7, 2009, http://fit.powerauthority.on.ca/Storage/10147_FIT_Stakeholder_Engagement_-_Session_4_FIT_Price_Schedule_FINAL_(HP).pdf.

[31] Investor's Schedule of Exhibits **C0354** (004356) Ontario's Feed-in Tariff Program, Two-Year Review Report, March 2012, http://www.energy.gov.on.ca/docs/en/FIT-Review-Report.pdf

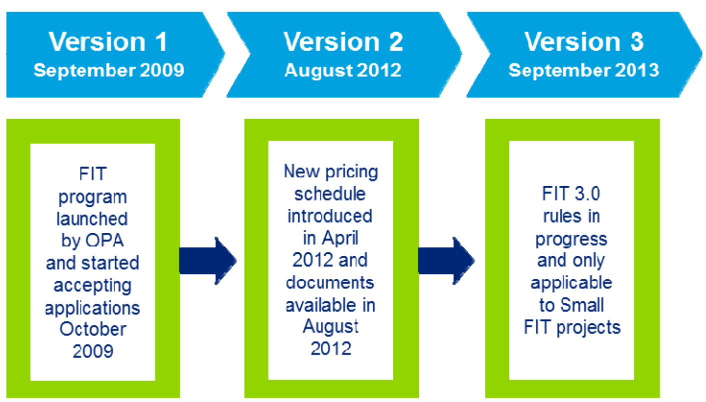
[32] Investor's Schedule of Exhibits **C0355** (004357) Ontario Power Authority, Pricing Schedule, August 2010. http://fit.powerauthority.on.ca/Storage/11122_FIT_Price_Schedule_August_13_2010.pdf

[33] Investor's Schedule of Exhibits **C0356** (004358) Ontario Power Authority Pricing Schedule, April 2012,

2.7 In March 2013, the OPA sent out a stakeholder feedback questionnaire to aid in the development of the 2013 pricing schedule. The stakeholders included Ontario consumers, developers, distributors and generators. The questions covered cost of capital requirements, key cost drivers, Ontario versus global pricing differentials, rates of return on equity, current return on investment, price recommendations and other important information used to create a price structure.[34]

2.8 On June 12, 2013, the Minister of Energy directed the OPA to change the FIT program, including removing large projects from the program and develop a new process to procure large renewable energy capacity (over 500 kW). The OPA was expected to report back to the Minister by September 1, 2013 with interim recommendations. The goal of the new procurement process is to take into account the local needs before contracts are offered.[35] Pursuant to the June 12, 2013 direction, going forward, the FIT program will only be open to Small FIT projects (less than 500kW) for solar and on-farm biogas renewable projects.[36]

2.9 The FIT program was further updated in August 2013 with a new pricing schedule applicable to all new FIT contract offers. The final program documents for FIT 3.0 were released on October 9, 2013.[37] The following is a timeline of the FIT program updates summarized above:[38]



2.10 Consistent with the prior rules, prices are expected to increase annually over the contract by a percentage of the contract price based on the Consumer Price

http://fit.powerauthority.on.ca/sites/default/files/news/2013-FIT-Price-Comparison-Table.pdf

[34] Investor's Schedule of Exhibits **C0357** (004359) 2013 FIT Price Review Stakeholder Feedback, March 2013, ,http://www.biogasassociation.ca/bioExp/images/uploads/documents/2013/other/2013_Price_Review_Stakeholder_Feedback_Questionnaire.pdf

[35] Investor's Schedule of Exhibits **C0343** (004345) Ontario Power Association, Development of a New Large Renewable Procurement Process, August 30, 2013.

[36] Investor's Schedule of Exhibits **C0341** (004343) Ontario Power Association, FIT Rules Version 3.0- Draft, September 4, 2013, http://fit.powerauthority.on.ca/sites/default/files/page/FIT%20Rules%20DRAFT%20Version%203.pdf

[37] Investor's Schedule of Exhibits **C0342** (004344) Ontario Power Association, FIT 3.0 Final Program Documents October 9, 2013, http://fit.powerauthority.on.ca/newsroom/october-9-2013-FIT-3-final-documents

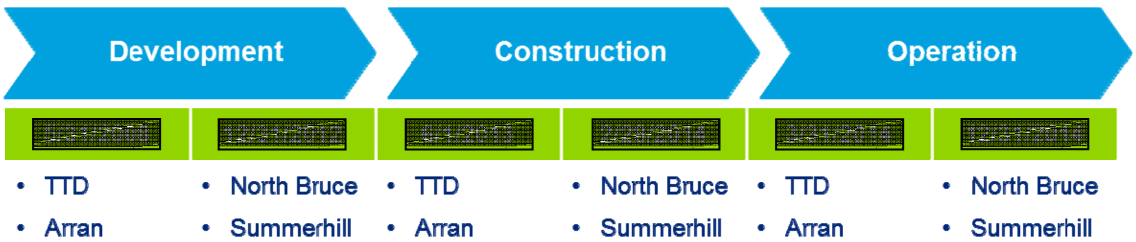
[38] Ontario Power Authority, FIT Program Newsroom, 2009-2013, Investor's Schedule of Exhibits (December 16, 2009 **C0345** (004347), August 10, 2012 **C0355** (004357), September 27, 2013 **C0347** (004349)), http://fit.powerauthority.on.ca/program-updates/newsroom

Index. There are further price adders based on aboriginal participation, community participation and municipal or public sector entity participation.[39]

Overview of the Projects

2.11 As noted above, there were four onshore wind Projects that Mesa Power had planned to construct and operate, with support from the FIT program.

2.12 The following chart is the forecast timeline for each wind farm project based on the three stages of development, construction and operation:[40]



TTD

2.13 TTD is designed to generate 144MW of wind power using [redacted] 1.6xle turbines, representing the type of turbine that would have met the Domestic Content Requirements of the FIT program.[41] This project is located in the Municipality of Central Huron and situated on agricultural land. [redacted] TTD applied for a FIT Contract in November 2009. The project had [redacted] properties (including [redacted] transferred from Summerhill) under option as at [redacted] Based on the GL Garrad Hassan assessment of the energy production report dated November 9, 2010, TTD was expected to generate the following:

WTG Class	1.6 xle	2.5 XL 85m	2.5 XL 100m
WTG Count	[redacted]	[redacted]	[redacted]
Nameplate	[redacted]	[redacted]	[redacted]

Arran

2.14 Arran is designed to generate 115 MW of wind power using [redacted] 1.6xle turbines.[43] This project is located in the Municipality of Arran-Elderslie and the Town of Saugeen Shores and is situated on agricultural land. [redacted]

[39] Investor's Schedule of Exhibits **C0341** (004343) Ontario Power Authority, FIT Rules Version 3.0 Draft, September 4, 2013, http://fit.powerauthority.on.ca/sites/default/files/page/FIT%20Rules%20DRAFT%20Version%203.pdf

[40] COD based on the timeline in the Amended GEIA Investor's Schedule of Exhibits **C0282**, and other project timelines based on Management's estimates, and project schedules prepared by Leader Resources Corp. (Investor's Schedule of Exhibits **C0384** (003333A), Investor's Schedule of Exhibits C0385 (003333B), Investor's Schedule of Exhibits **C0386** (003333C), Investor's Schedule of Exhibits **C0387** (003333D)), consistent with the claims made by Mesa Power.

[41] Investor's Schedule of Exhibits **C0364** (001810) TTD FIT Application, Investor's Schedule of Exh bits **C0378** (001971) TTD Assessment of Energy Production Report.

[42] Investor's Schedule of Exhibits **C0373** (001824 – 1.2.4) June 6, 2011.

[43] Notice of Intent to Submit a Claim to Arbitration, Mesa Power Group, LLC v. Government of Canada.

[redacted] Arran applied for a FIT Contract in November 2009. The project had 220 properties (including [redacted] transferred from North Bruce) under option as at [redacted] Based on the GL Garrad Hassan assessment of the energy production report dated June 25, 2010, Arran was expected to generate the following:

WTG Class	1.6 xle	2.5 xl 85m	2.5 xl 100m
WTG Count	[redacted]	[redacted]	[redacted]
Nameplate	[redacted]	[redacted]	[redacted]

North Bruce

2.15 North Bruce applied for two FIT Contracts in May 2010[45] for a total of 200 MW of wind power using [redacted] 1.6xle turbines.[46] [redacted] when FIT Contracts were not awarded. As at July 2011, North Bruce had [redacted] properties under option ([redacted] transferred to Arran). Wind data is being collected in the project area from three meteorological towers. [redacted]

Summerhill

2.16 Summerhill applied for two FIT Contracts in May 2010[47] for a total of 100 MW of wind power using [redacted] 1.6xle turbines.[48] The project started [redacted] d and was put on hold in July 2011, when FIT Contracts were not awarded. As at July 2011, Summerhill had [redacted] properties under option ([redacted] transferred to TTD). Summerhill is in same municipality, Central Heron, as TTD. Wind data is being collected in the project area from two meteorological towers installed in [redacted].

Status of the Projects

2.17 The following is a summary of the status of each project, including the major Renewable Energy Application required reports and studies as of July 21, 2011:[49]

	TTD	Arran	North Bruce	Summerhill
General consultation (land owners, public, government,	Yes	Yes	Yes	Yes

[44] Investor's Schedule of Exhibits **C0370** (001821 – 1.2.1) June 6, 2011.
[45] Investor's Schedule of Exhibits **C0371** (001822-1.2.2)
[46] Notice of Intent to Submit a Claim to Arbitration, Mesa Power Group, LLC v. Government of Canada.
[47] Investor's Schedule of Exhibits **C0372** (001823 – 1.2.3)
[48] Notice of Intent to Submit a Claim to Arbitration, Mesa Power Group, LLC v. Government of Canada.
[49] Investor's Schedule of Exhibits **C0371** (001822-1.2.2), Investor's Schedule of Exhibits **C0372** (001823-1.2.3), Investor's Schedule of Exh bits **C0373** (001824-1.2.4), Investor's Schedule of Exhibits **C0370** (001821-1.2.1), Investor's Schedule of Exhibits **C0359** (001799). This information was obtained from documents dated July 21, 2011.If a category is classified as 'Yes', the reports have been completed or are in the draft stage.

Aboriginal)

Project description report	Yes	Yes	In progress	In progress
Initial public consultation/engagement	Yes	Yes	Yes – questions still outstanding	Yes – questions still outstanding
Municipal forms and reports (construction plan, design and operations report, decommissioning plan)	Yes	Yes	No	No
Noise impact assessment report	Yes	In progress	Preliminary mapping reviewed only	Preliminary mapping reviewed only
Natural heritage assessment and environmental impact studies	Yes	In progress	Preliminary bird studies only	Preliminary bird studies only
Water body assessment report	Yes	In progress	No	No
Archaeology reports	Yes	In progress	In progress	In progress
Wind turbine specifications report	Yes	Yes	No	No
Built heritage assessment report	Yes	In progress	Research completed	Research completed
Final public consultation/engagement	In progress	In progress	No	No
Consultation report	Yes	N/A	No	No
FIT application	November 2009	November 2009	May 2010	May 2010

2.18 As illustrated in the chart above, TTD and Arran had completed a significant portion of the REA process. Summerhill and North Bruce had also made progress; however, to a lesser extent given the relative stage of the projects. Given the proximity of the locations of the North Bruce and Summerhill projects, many of the studies commissioned for the TTD and Arran projects could be leveraged for the purpose of North Bruce and Summerhill.

General Electric Company contracts

2.19 On [redacted], Mesa Power entered into a Master Turbine Sale Agreement ("MTSA") with General Electric Company ("GE"). The MTSA was for 667 1.5xle wind turbines. Mesa Power was required to pay an initial deposit for the turbines which would be lost if it did not order its turbines by the agreed upon dates.[50] The deposit of [redacted] was paid on [redacted].

2.20 On [redacted] Mesa Power Pampa, LLC[51] entered into an Amended and Restated Master Turbine Sale Agreement ("Amended MTSA") with GE[52]. The Amended MTSA was for [redacted] 1.5XLE or 1.6XLE wind turbines, [redacted] of which were to be shipped [redacted] and [redacted] to be shipped [redacted] If Mesa Power required additional wind turbine units, it was required to purchase the next [redacted] wind turbines from GE.

2.21 [redacted] On [redacted] Mesa Power forfeited a portion of the deposit based on the termination notice period relating to [redacted] wind turbines scheduled to have been delivered by [redacted]

2.22 On [redacted] Mesa Power Pampa, LLC entered into a Second Amended and Restated Master Turbine Sale Agreement ("Second Amended MTSA") with GE. In this agreement, Mesa Power purchased [redacted] 1.6xle-100 and [redacted] 1.6xle-82.5 turbines which were scheduled to be shipped [redacted] GE retained the initial forfeited deposit of [redacted] and retained the remaining deposit paid by Mesa Power as of [redacted] as a portion of the initial payment for the Second Amended MTSA.

2.23 The [redacted] deposit was ultimately forfeited on [redacted] when Mesa Power terminated the Second Amended MTSA.[54]

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[50] These dates changed over the course of the amended agreements and change orders.

[51] [redacted] Investor's Schedule of Exhibits **C0379** (002023-2.1.2) Amended and Restated Master Turbine Sale Agreement For the Sale of Power Generation Equipment and Related Services [redacted]

[53] Investor's Schedule of Exhibits **C0383** (002438) Letter from GE to Mesa Power dated [redacted]

[54] Investor's Schedule of Exhibits **C0382** (002437) Letter from Mesa Power to GE dated [redacted]

3 Industry and economic analysis

3.1 We have set out the industry and economic factors that were considered relevant for the purpose of our analyses in Appendix C.

4 Economic loss analysis

Summary of conclusions

4.1 As noted above, there are several claims being made by Mesa Power under Articles 1102, 1103, 1105 and 1106 of the NAFTA. We have outlined the methodology and performed the calculations for each of the Articles separately given the necessary inputs to each analysis. The following summarizes each of the claims and the Economic Losses we have determined related thereto, if any:

a) Articles 1102 and 1103:

i) Base Case Scenario: This scenario is based on the assumption that Mesa Power obtained FIT Contracts for the Projects and would have developed the wind farms in accordance with the Domestic Content Requirements and operated the Projects to the end of their FIT Contracts;

ii) Economic Development Adder: The Economic Development Adder was considered to be an incremental loss and has been quantified based on the assumption that Mesa Power would receive the additional 0.27 cents per kWh that was offered to the Korean Consortium as part of the Amended GEIA.[55]

iii) Capacity Expansion: The additional 10% of capacity (the “Capacity Expansion”) is considered to be an incremental loss and has been quantified based on the assumption that Mesa Power would have the ability to increase the capacity of its Projects by 10% that was offered to the Korean Consortium as part of the GEIA.[56] [57] Further, we have also considered the incremental Economic Development Adder applicable to the Capacity Expansion.

iv) Deposit with General Electric forfeited: Consistent with the assumption that Mesa Power would have obtained FIT Contracts for the Projects and would have developed the wind farms in accordance with the timelines outlined in the FIT applications, the deposit would not have been forfeited to GE. As outlined in the MTSA with GE, Mesa Power was obligated to pay an initial deposit to secure supply of turbines for the Projects. On [redacted] Mesa Power forfeited a portion of the deposit relating to [redacted] model 1.6xle turbines[58] and on [redacted]2, Mesa Power forfeited the remaining [redacted] when it terminated the Second

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[55] Investor’s Schedule of Exhibits **C0282** Green Energy Investment Agreement – Amending Agreement July 29, 2011
[56] Investor’s Schedule of Exhibits **C0322** (PH 765) Green Energy Investment Agreement January 21, 2010
[57] Letter from Mesa Power Group to Deloitte LLP, dated November 15, 2013 **C0075**, paragraph 12.
[58] Investor’s Schedule of Exhibits **C0383** (002438) Letter from GE to Mesa Power dated [redacted]

Amended and Restated MTSA.[59] Based on the nature of our determination of Economic Losses (which reflect the capital cost of the turbines as an outlay) the forfeited deposit must be added to the economic loss otherwise determined.

v) Past costs: We have quantified the Economic Losses relating to all development costs incurred by Mesa Power in relation to preparing the Projects for commercial operation. Although these costs would have been incurred to achieve profits, we have added the past costs to the losses determined in Base Case scenario as they have already been deducted in the determination of the lost profits and were incurred by Mesa Power and therefore cannot be avoided.

b) Article 1106:

i) Performance requirements: As described above, the claim related to Article 1106 relates to the Domestic Content Requirements imposed by Canada thereby increasing the capital and operating costs of the Projects, which we understand to be included in the claim for Articles 1102 and 1103, as discussed above. Such costs were considered to be incremental Economic Losses and were quantified based on the assumption that Mesa Power was not obligated to comply with the Domestic Content Requirements in the FIT program.[60] Further, additional production was attainable using the 2.5XL turbine, thereby increasing revenue potential. We have also calculated the Economic Losses related to Article 1106 for the Base Case, Economic Development Adder and the Capacity Expansion separately.

c) Article 1105: As noted above, Article 1105 includes all Economic Losses quantified within 1102, 1103 and 1106.

4.2 We have determined the Economic Losses over the period from the commencement of the development of the Projects[61] to December 31, 2034 which represents the development period for the Projects to the end of the latest FIT Contract period for the Projects (the "Period of Loss").

4.3 Based on the scope of our review (Appendix A), assumptions (Appendix B) and our research, analysis and experience, our opinion of the Economic Losses for the Period of Loss as at the Valuation Dates, as set out in further detail in this section, is summarized in the table below. If requested to select a single point estimate of the Economic Losses, we would suggest the midpoint of the range of $624.1 million to $683.2 million (NAFTA 1102/1103/1105), or $653.7 million, set out below. The Economic Losses related to Article 1106 while separately determined as $101.2 million to $111.3 million, with a midpoint of $106.3 million,

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[59] Investor's Schedule of Exhibits **C0382** (002437) Letter from Mesa Power to GE dated [redacted]

[60] Investor's Schedule of Exhibits **C0340** (004342) Ontario Power Association, FIT Rules Version 1.5 – June 3, 2011, Domestic Content (Article 6.4) http://fit.powerauthority.on.ca/sites/default/files/FIT%20Rules_Version%201.5_June%203%202011_1.pdf

[61] The commencement of the development of the Projects dates back as early as [redacted] Economic losses only in respect of the past costs relate to the time period prior to the time the FIT applications were submitted.

are included in the Economic Losses for Articles 1102, 1103 and 1105, and are not additive thereto. The Economic Losses presented herein exclude any consideration for pre-judgment and post-judgment interest, as well as any legal or other fees incurred by the Plaintiffs in this matter.

CAD 000s	Low	High
NAFTA 1102/1103/1105		
Base Case	303,000	345,000
Economic Development Adder	20,000	22,000
Capacity Expansion	33,000	38,000
Economic Development Adder applicable to Capacity Expansion	2,000	2,000
Past costs incurred	8,100	8,100
General Electric deposit forfeited	156,833	156,833
NAFTA 1106 (below)	101,200	111,300
Total NAFTA 1105	**624,133**	**683,233**
NAFTA 1106		
Base Case	91,000	100,000
Economic Development Adder	1,000	1,000
Capacity Expansion	9,000	10,000
Economic Development Adder applicable to Capacity Expansion	200	300
Total NAFTA 1106	**101,200**	**111,300**

Quantification of Economic Losses

Methodology and approach

Articles 1102 and 1103 – Base Case Scenario

4.4 A discounted cash flow ("DCF") approach was selected as the most appropriate approach for the purpose of determining the Economic Losses related to the Base Case Scenario.

4.5 Under the DCF approach, the Economic Losses are based on the net present value of expected future cash flows to be generated from developing and operating the Projects. Specifically, the discretionary, post-interest, after-tax cash flow that the business is expected to generate is projected over an explicit forecast period, which in this case is consistent with the 20-year term of the FIT Contract. The projected cash flows over the discrete forecast period are then discounted to their present value equivalent using an appropriate risk adjusted rate of return, resulting in the Economic Losses of the Projects at the Valuation Dates related to Articles 1102 and 1103.

4.6 We have quantified the Economic Losses relating to all four of Mesa Power's projects. Although Summerhill and North Bruce were ranked below the 750MW available capacity for the Bruce Region, had the aforementioned projects been given the same treatment as the Korean Consortium, they would have also been provided FIT contracts.

4.7 A DCF approach was considered to be the most appropriate and reliable approach for the following reasons:

a) Revenues can be forecast with a relatively high degree of confidence. The price per kWh is established by contract while the wind production can be reasonably estimated, with estimates supported by independent wind studies, and therefore revenues were readily determinable;

b) The majority of the capital costs would have been contractual, and have been compared to benchmark data. The largest component of the capital costs, the wind turbines were subject to a contract with GE;

c) Operating costs are expected to be relatively stable and can be established contractually or estimated using benchmark data or reasonable estimates. In addition, operating costs which are not contractually established are not expected to be significant; and,

d) Engineering for the Projects do not involve any novel technology (i.e. there are similar projects operating domestically and internationally).

As a result, the inputs to the DCF approach can be estimated in a reliable manner with a relatively high degree of confidence.

4.8 Further, the DCF approach takes into account the amount, timing, and expectation of achieving projected levered cash flows expected to be generated by the net operating assets which provides a more detailed reflection of the future cash flow generated by the Projects.

4.9 We have not included a reclamation cost or salvage value in the DCF. Based on discussions with Management and supported by our industry research, we have assumed the costs required to restore the land to its initial use would approximate the value related to the continued use or salvage value of the turbines[62].

4.10 The discount rate was determined based on our review of the available returns on alternative investments, the operations of Mesa Power, the relative risks of the Projects, and assuming a market based capital structure, as discussed in further detail below.

4.11 We have assumed the Valuation Dates related to Article 1102 and 1103 (Base Case Scenario) were January 21, 2010 and May 29, 2010 for TTD/Arran and North Bruce/Summerhill, respectively, as described above. As such, we have

[62] Letter from Mesa Power Group to Deloitte LLP, dated November 15, 2013 **C0075**, paragraph 11.

used these dates for the purpose of the present value calculations (i.e. the Economic Losses were determined as of January 21, 2010 and May 29, 2010).

4.12 We have added the following to the Base Case Scenario:

a) Past costs: We have added the costs incurred related to the development of the Projects; and

b) GE deposit forfeited: We have also added the deposit that Mesa Power forfeited as the Company was not able to and did not order the turbines within the required period[63].

Article 1102 and 1103 – Economic Development Adder

4.13 In order to quantify the impact of the Economic Development Adder that was provided to the Korean Consortium, a DCF approach as described in Sections 4.5 to 4.8, was considered. Under this approach, we forecast the revenues based on the Base Case Scenario and added 0.27 cents per kWh, which represents the Economic Development Adder (i.e. the additional revenue per kWh) that was offered to the Korean Consortium. We then determined the Economic Losses under Articles 1102 and 1103 related to the Economic Development Adder to be the difference in the net present values of cash flows including and excluding the Economic Development Adder.

Article 1102 and 1103 – Capacity Expansion

4.14 In order to quantify the impact of the increase in capacity of 10% that was offered to the Korean Consortium, a DCF approach as described in Sections 4.5 to 4.8, was considered. Under this approach, we determined the number of turbines required to achieve the additional 10% of capacity and then forecast the revenues, operating costs, capital costs and financing costs that would relate to the Projects including the increased capacity. We then determined the Economic Losses under Articles 1102 and 1103 related to the Capacity Expansion to be the difference in the net present values of cash flows including and excluding the increased capacity. We have also separately calculated the incremental Economic Losses arising from the Economic Development Adder associated with the Capacity Expansion.

Article 1106 – Performance Requirements

4.15 In order to quantify the impact of the Domestic Content Requirements under the FIT program (included in the claims related to Articles 1102 and 1103), we considered the following:

a) Wind turbines: We understand that GE was unable to commit to various turbines that would meet the domestic content requirements. As a result, Mesa transmitted its FIT application using the 1.6 xle which Mesa believed at that time was the only turbine that would meet the Domestic Content

[63] Letter from Mesa Power Group to Deloitte LLP, dated November 15, 2013 **C0075**, paragraph 2.

Requirements[64]. Based on our discussions with Mesa Power's management ("Management") we understand the preferred turbine for each of the projects would have been the 2.5XL wind turbine also from GE, which GE could not guarantee would have met the Domestic Requirements at that time.[65] We have quantified the Economic Losses related to the Domestic Content Requirements as the difference in the net present value of the cash flows (as discussed in paragraphs 4.5 to 4.8) arising from the incremental cash flows that would have been realized if Mesa Power was able to utilize the 2.5XL turbine rather than the 1.6xle turbine given the Domestic Content Requirements.

b) Constructions costs: We understand that Mesa Power had selected a contractor, Mortenson Construction ("Mortenson"), to provide engineering, procurement and construction services for the Projects. Based on price quotations Mortenson provided to Mesa Power[66], we understand that in order to meet the Domestic Content Requirements, incremental construction costs would have been required. Specifically, we quantified the Economic Losses related to the Domestic Content Requirements including the difference in the net present value of the cash flows arising from the incremental construction costs.

c) Operating costs: We understand that several operating costs are dependent on the number of turbines required. If Mesa Power was not required to meet the Domestic Content Requirements and was able to use the 2.5XL wind turbines, the Projects would require fewer turbines for the similar nameplate capacity[67] and therefore would be more profitable, due to a reduction in costs that related to the number of turbines required for the project. As a result, we have also included such reduced operating costs in our determination of the Economic Losses related to the Domestic Content Requirements.

d) Economic Development Adder: As discussed above, we have added the incremental Economic Development Adder that would have been received in respect of the additional wind production generated from the 2.5XL turbine.

e) Capacity Expansion: Consistent with the above, we have added the incremental Capacity Expansion that would have been granted in respect of the additional wind production generated from the 2.5XL turbine. We have also calculated the incremental Economic Losses arising from the Economic Development Adder associated with the Capacity Expansion.

Article 1105 – Minimum Standard of Treatment

4.16 In order to quantify the impact of the Economic Losses related to Article 1105, we have considered the following as discussed above:

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[64] Letter from Mesa Power Group to Deloitte LLP, dated November 15, paragraph 6.
[65] Investor's Schedule of Exhibits **C0107** (003731) E-mail from Michael Volpe to Cole Robertson dated August 5, 2010.
[66] Investor's Schedule of Exhibits **C0206** (004341) LRS Ontario Project Cost Summary for DC Impact
[67] Nameplate capacity refers to the amount of MW produced per year.

a) All Economic Losses quantified for 1102 and 1103, including the Base Case, the Economic Development Adder, the Capacity Expansion, GE deposit forfeited and the past costs; and

b) The incremental Economic Losses related to the Domestic Content Requirements.

Key assumptions

4.17 For the purposes of our analysis and calculation of the Economic Losses, if any, suffered by Mesa Power, we have assumed that the alleged breaches by Canada of its NAFTA obligations are found to have occurred.

4.18 The following summarizes the key assumptions underlying the quantification of the Economic Losses, in addition to the assumptions set out in Appendix B and elsewhere in this report:

a) The Projects obtained a FIT Contract as we have assumed Mesa Power would have been provided with the same treatment as the Korean Consortium;

b) All environmental and other associated approvals are received under the REA process and therefore a notice to proceed is obtained for the Projects[68]. Mesa Power has completed a significant amount of the REA process for TTD and Arran (as summarized above) and has the experience and expertise to bring the Projects to commercial operation, and pursuant to the GEIA, the Government of Ontario would have facilitated the necessary regulatory approvals and permits;[69]

c) Financing is secured which is reasonable given Mesa Power has had preliminary discussions with lenders and although financing commitment letters had not been obtained, we understand there was significant interest on the part of lenders. We also understand based on Deloitte's knowledge of financing of renewable energy projects, that financing was likely available for these types of projects;

d) Mesa had the financial capacity to fund the equity required to reach commercial operation[70]; and

e) The Projects are able to meet the same construction timeline that the Korean Consortium was expecting to achieve in respect of its projects. This assumption is reasonable as these timelines are consistent with the construction timelines provided by Leader Resources Services Corp in respect of the Projects[71].

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[68] Letter from Mesa Power Group to Deloitte LLP, dated November 15, 2013 **C0075**, paragraph 1.
[69] Investor's Schedule of Exhibits **C0322** (PH 765) Green Energy Investment Agreement January 21, 2010 (article 7.3a).
[70] Letter from Mesa Power Group to Deloitte LLP, dated November 15, 2013 **C0075**, paragraph 13.
[71] Letter from Mesa Power Group to Deloitte LLP, dated November 15, 2013 **C0075**, paragraphs 4 and 5.

4.19 Due to the nature of our calculations, the development costs incurred by Mesa Power[72] plus the GE forfeited deposit must be added to the calculation of Economic Losses as these costs were considered in the DCF calculations discussed above and can no longer be recovered.

Key parameters and inputs

Articles 1102 and 1103 – Base Case Scenario

4.20 Economic Losses have been determined for the Period of Loss considering the following:

a) Historical development expenditures have been incurred from the commencement of the Projects to the Valuation Dates related to Articles 1102 and 1103;

b) a development period ranging from [redacted] for TTD and Arran, respectively, to [redacted] for Summerhill and North Bruce leading up to the construction period. Summerhill and North Bruce have shorter development periods as they are greenfield projects in close proximity to the other Projects and therefore through leveraging studies and analysis completed for the TTD and Arran projects Mesa Power can develop the Summerhill and North Bruce projects in an condensed time frame[73];

c) a ten-month construction period from the end of the development period to the commercial operating date ("COD")[74];

d) a 20-year operating period; and

e) No terminal value as we have assumed the continued use or salvage value approximates the reclamation costs[75].

Construction operation date

4.21 Consistent with the overall NAFTA claim made by Mesa Power, we have selected a COD based on the Korean Consortium's proposed timelines for its projects. We have assumed that such timelines represent an approval timeline that would be achievable had Mesa Power received the same treatment as the Korean Consortium. The timelines proposed for the Korean Consortium's projects in the Amended GEIA are as follows:

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[72] As noted above, such costs were either inflated or present valued, depending on the when the costs were incurred.
[73] Letter from Mesa Power Group to Deloitte LLP, dated November 15, 2013 **C0075**, paragraph 4.
[74] Letter from Mesa Power Group to Deloitte LLP, dated November 15, 2013 **C0075**, paragraph 5.
[75] Letter from Mesa Power Group to Deloitte LLP, dated November 15, 2013 **C0075**, paragraph 11.

Phase	Targeted Generation Capacity – Wind (MW)	Targeted COD (as set in Jan 21, 2010 agreement)[76]	Targeted COD (as set in July 28, 2011 amended agreement)[77]
Phase 1	400	March 31, 2013	March 31, 2014
Phase 2	400	December 31, 2013	December 31, 2014
Phase 3	400	December 31, 2014	December 31, 2015
Phase 4	400	December 31, 2015	December 31, 2016
Phase 5	400	December 31, 2016	December 31, 2017

4.22 We have assumed a COD of March 31, 2014 for TTD and Arran which is consistent with the expected COD for the Korean Consortium's phase 1 projects.[78] March 31, 2014 was determined to be a reasonably achievable COD given that:

a) The FIT applications had an expected [redacted] included therein.

b) According to the charts prepared by Leader Resources Services Corp. dated December 2010[79], the CODs for TTD and Arran were expected to be [redacted] and [redacted] respectively; and

c) The Korean Consortium would have had approximately 2 years and 8 months from the Amended GEIA to the targeted COD. Therefore, the Korean Consortium's proposed timeline was in line with the expected timeline for Mesa Power's Projects had they received FIT Contracts on July 4, 2011, given that they would have had approximately 2 years and 9 months to the targeted COD.

4.23 We have assumed the COD for the Summerhill and North Bruce projects would be [redacted] This is based on the expected timing for the Korean Consortium's phase 2 projects.[80] [redacted] was determined to be a reasonably achievable COD given that the FIT applications for Summerhill and North Bruce had an expected COD of [redacted].

Revenue

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[76] Investor's Schedule of Exhibits **C0322** (PH 765) Green Energy Investment Agreement January 21, 2010 (article 3.2).
[77] Investor's Schedule of Exhibits **C0282** Green Energy Investment Agreement – Amending Agreement July 29, 2011 (article 7).
[78] Investor's Schedule of Exhibits **C0282** Green Energy Investment Agreement – Amending Agreement July 29, 2011 (article 6).
[79] Investor's Schedule of Exhibits **C0384** (003333A), Investor's Schedule of Exh bits **C0385** (003333B), Investor's Schedule of Exhibits **C0386** (003333C), Investor's Schedule of Exhibits **C0387** (003333D) TTD and Arran Wind Energy Project Schedules.
[80] TTD, Arran, Summerhill, and North Bruce FIT Applications (Investor's Schedule of Exhibits **C0129** (001805), Investor's Schedule of Exh bits **C0360** (001806), Investor's Schedule of Exhibits **C0361** (001807), Investor's Schedule of Exh bits **C0362** (001808), Investor's Schedule of Exh bits **C0363** (001809), Investor's Schedule of Exhibits **C0364** (001810).

Projects	Expected COD
TTD & Arran	[redacted]
Summerhill & North Bruce	[redacted]

4.24 The following describes the components of revenue that were considered as part of our analysis.

4.25 Power price: For all of the Projects we have assumed a contract price of $0.135 per kWh, equivalent to $135 per MWh, which was the guaranteed power price set out by the OPA in July 2011 for onshore wind energy projects. In accordance with the terms set out in the FIT Contract,[81] we have also inflation-indexed the price per MWh to reflect the period between the date the FIT pricing was set and the COD. The inflation-indexed price in effect at the COD is $142.40 per MWh for Arran and TTD and $145.04 for Summerhill and North Bruce.

4.26 Power price escalation: Based on the terms of the FIT Contract, the escalation percentage is 20.0%, meaning that 20.0% of the price per MWh is to be inflation-adjusted on an annual basis during the operation of the Projects. We have escalated the power price annually by 0.42% which is equal to 20% of the average forecast consumer price index inflation rate[82] from 2014 to 2017 of 2.1% as at the date of this report.

4.27 Annual energy production: We have assumed an average annual energy production volume based on the studies commissioned and prepared by GL Garrad Hassan[83], as of [redacted]. As of that date and the technology available at that time, based on each project's rated capacity, the annual energy production volumes translate to net capacity factors as summarized below. We understand that wind studies had not yet been prepared for Summerhill or North Bruce. As such, we have used Management's estimate and the information provided in the FIT applications[84] to estimate the values below.

	1.6xle			2.5XL[85]		
	Average annual energy production	Capacity	Net capacity factor	Average annual energy production	Capacity	Net capacity factor
TTD	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Arran	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Summerhill	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
North Bruce	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]

4.28 We have relied on the wind energy report for Arran for the purpose of determining the Economic Losses related to North Bruce and relied on the wind

[81] Investor's Schedule of Exhibits **C0347** (004349) FIT Contract Version 1.5.1 July 15, 2011, Indexation (Exhibit B, Article 1.3). http://fit.powerauthority.on.ca/sites/default/files/FIT%20Rules%20Version%201%205%201_Program%20Review_0.pdf

[82] Investor's Schedule of Exhibits **C0348** (004350) Economic Intelligence Unit Canada Country Report, September 2013. Based on the FIT Standard Definitions Version 1.5.1 July 15, 2011, the consumer price index used to calculate the power price escalation is Ontario's consumer price index for "All Items" established by Statistics Canada. http://fit.powerauthority.on.ca/sites/default/files/FIT%20Standard%20Definitions%20Version%201.5.1.pdf

[83] Investor's Schedule of Exhibits **C0374** (001852-3.1.2) TTD Assessment of Energy Production (001971 page 1), [redacted]

Investor's Schedule of Exhibits **C0362** (001808), Investor's Schedule of Exhibits **C0363** (001809) Summerhill FIT applications, Investor's Schedule of Exh bits **C0360** (001806), Investor's Schedule of Exhibits **C0361** (001807) North Bruce FIT applications.

[85] We have included the information related to the 2.5XL turbines at this point for reference only, for the purpose of the Economic Losses related to the Domestic Content Requirements detailed below.

energy report for TTD for the purpose of determining the Economic Losses related to Summerhill, given the close proximity of the properties and the expected wind attributes.

4.29 The net capacity factor is based on a [redacted] statistical assumption which we understand reflects the most likely outcome of wind energy production and was therefore determined to be appropriate for the purpose of our analysis.

Development and construction costs

4.30 Development costs include all costs incurred to plan the development of the Projects, to obtain the necessary feasibility and environmental studies for approvals, and any other costs incurred prior to construction which are necessary to bring the project to the construction stage. The development costs and development periods are summarized below:

	1.6xle		2.5XL	
	Development costs	Development period (months)	Development costs	Development period (months)
TTD	[redacted]	[redacted]	[redacted]	[redacted]
Arran	[redacted]	[redacted]	[redacted]	[redacted]
Summerhill	[redacted]	[redacted]	[redacted]	[redacted]
North Bruce	[redacted]	[redacted]	[redacted]	[redacted]

4.31 The development costs for TTD and Arran are significantly higher than Summerhill and North Bruce as they were purchased from other developers and include earn out payments to the previous owners when the notice to proceeds are issued. Summerhill and North Bruce are greenfield projects commenced by Mesa Power and therefore do not require any earn out payments. Due to their proximity, Mesa Power can leverage studies and analyses completed for the Arran and TTD projects to reduce the costs and development period for the North Bruce and Summerhill projects, respectively.

4.32 The two main components of construction costs are the costs of the wind turbines and costs paid to a contractor to construct the infrastructure, the foundations and install / erect the wind turbines.

a) Wind turbine pricing: We have considered the cost of the 1.6xle wind turbines based on the component costs of the wind turbines and the prices stated in the agreements and change orders exchanged between Mesa Power and GE. [86] Specifically, we have referred to the change order dated [redacted] to obtain the 1.6xle turbine pricing summarized below.

[86] Investor's Schedule of Exhibits **C0379** (002023-2.1.2) Amended and Restated Master Turbine Sale Agreement For the Sale of Power Generation Equipment and Related Services [redacted]
[87] Investor's Schedule of Exhibits **C0380** (002024-2.1.3) External Change Order Proposal No. 3 February 8, 2011

b) Engineering, procurement and construction (“EPC”) pricing: Based on our understanding, Mesa Power would have selected Mortenson as the contractor to construct the Projects’ wind turbines.[88] EPC costs relate to various elements including access roads, the turbine foundation, turbine erection, the overhead collector system and a contingency[89]. We have considered the contractor costs based on price quotations provided by Mortenson.

4.33 We have summarized the capital costs by project below based on [redacted] price quotes for turbines and [redacted] quotes for engineering, procurement and construction costs. The total construction costs have been adjusted for inflation and stated in Canadian dollars:

USD	1.6xle turbine	2.5xle turbine[90]
TTD		
Wind Turbine Generator (“WTG”) cost	[redacted]	[redacted]
Other WTG related costs	[redacted]	[redacted]
Other WTG related costs per project	[redacted]	[redacted]
Engineering, procurement and construction costs	[redacted]	[redacted]
Total construction costs (CAD)	[redacted]	[redacted]
Arran		
Wind Turbine Generator (“WTG”) cost	[redacted]	[redacted]
Other WTG related costs	[redacted]	[redacted]
Other WTG related costs per project	[redacted]	[redacted]
Engineering, procurement and construction costs	[redacted]	[redacted]
Total construction costs (CAD)	[redacted]	[redacted]
Summerhill		
Wind Turbine Generator (“WTG”) cost	[redacted]	[redacted]
Other WTG related costs per WTG	[redacted]	[redacted]
Other WTG related costs per project	[redacted]	[redacted]
Engineering, procurement and construction costs	[redacted]	[redacted]
Total construction costs (CAD)	[redacted]	[redacted]
North Bruce		
Wind Turbine Generator (“WTG”) cost	[redacted]	[redacted]
Other WTG related costs per WTG	[redacted]	[redacted]

[88] Investor’s Schedule of Exhibits **C0376** (001856-3.2.3) TTD Mortenson 1.6xle quote, Investor’s Schedule of Exh bits **C0358** (000967-9.15-1.1) TTD Mortenson 2.5XL quote, Investor’s Schedule of Exhibits **C0375** (001854-3.2.1) Arran Mortenson 1.6xle quote.

[89] A contingency increases the overall cost estimate in order to account for potential cost overruns.

[90] Letter from Mesa Power Group to Deloitte LLP, dated November 15, 2013 **C0075**, paragraph 7.

[91] Based on the GE pricing, we have assumed the cost of [redacted]

Other WTG related costs per project	[redacted]	[redacted]
Engineering, procurement and construction costs	[redacted]	[redacted]
Total construction costs (CAD)	[redacted]	[redacted]

4.34 In order to test the reasonability of the estimated capital costs, we have considered capital costs per MWh based on industry reports in Schedule 7 (and summarized below) as a benchmark for the Projects' capital costs (including development costs).

	Project capacity	Total capital costs (US$M)	Capital costs US$ per MW	Industry reports Low	Industry reports Average	Industry reports Median	Industry reports High
TTD	[redacted]	[redacted]	[redacted]	1.75	2.03	2.05	2.22
Arran	[redacted]	[redacted]	[redacted]	1.75	2.03	2.05	2.22
Summerhill	[redacted]	[redacted]	[redacted]	1.75	2.03	2.05	2.22
North Bruce	[redacted]	[redacted]	[redacted]	1.75	2.03	2.05	2.22

4.35 Industry reports suggest that capital costs should be in the range of $1.75 to $2.22 per MWh. The capital costs estimated for the Projects are within the range of the benchmark data, and approximate the median capital cost per Mw. Therefore, we have considered the capital costs estimated to be reasonable.

Operating costs

4.36 We have considered the following operating costs in our determination of the Economic Losses of the Projects[92]:

a) Land royalty payments: We understand that Mesa Power entered into land option agreements for each project. Based on discussions with Management and a review of a sample of the land option agreements, Mesa Power has agreed to pay landowners a royalty in the range of [redacted] project revenues with some contracts increasing with the price per kW received for the Project;

b) Asset manager: Each wind farm requires an individual to manage the project during commercial operation. Based on discussions with Management, asset manager expenses are estimated to be [redacted] in the first year of operations and are estimated to grow at a rate of [redacted] annually thereafter based on the long term rate of inflation as at the Valuation Dates related to Articles 1102 and 1103;

c) Planned maintenance: These costs are incurred to service the turbines. Based on discussions with Management, planned maintenance costs are

[92] Letter from Mesa Power Group to Deloitte LLP, dated November 15, 2013 **C0075**, paragraph 10 (excluding land royalty payments).

estimated based on the number of turbines and the type of turbine. The cost is estimated to increase at a rate of [redacted] annually thereafter based on the long term rate of inflation as at the Valuation Dates related to Articles 1102 and 1103;

d) Unplanned maintenance: These costs represent the potential turbine maintenance costs that are not included in the planned maintenance costs. We understand that based on Management's experience, they have estimated a cost of [redacted] per turbine for the first year of operations. This cost is estimated to increase at a rate of [redacted] annually thereafter based on the long term rate of inflation as at the Valuation Dates related to Articles 1102 and 1103;

e) Transmission charge: Transmission charges are incurred when transmitting energy over the transmission grid. Based on discussions with Management, transmission charges are estimated to be [redacted] in the first year of operations for TTD and [redacted] in the first year for all other projects. TTD was expected to have a higher transmission charge as the other Projects had a transmission line running through them but TTD required a line extension. The cost is then estimated to increase at a rate of [redacted] annually thereafter based on the long term rate of inflation as at the Valuation Dates related to Articles 1102 and 1103;

f) Balance of plant ("BOP") maintenance: BOP maintenance costs relating to the wind farm, other than the wind turbines, are forecast to be [redacted] in the first year of operations and are estimated to grow at a rate of [redacted] annually thereafter based on the long term rate of inflation as at the Valuation Dates related to Articles 1102 and 1103;

g) Property taxes: Management has indicated that property taxes would have ranged from [redacted] annually based on previous property tax assessments, which we have assumed to increase based on the long term rate of inflation as at the Valuation Dates related to Articles 1102 and 1103;

h) Insurance: Based on discussions with Management, insurance costs are estimated to be [redacted] in the first year of operations for TTD and North Bruce and [redacted] in the first year for Arran and Summerhill. We understand that Management had not yet negotiated its insurance costs and as such, this is an estimate based on previous experience. The costs are estimated to increase at a rate of [redacted] annually thereafter based on the long term rate of inflation as at the Valuation Dates related to Articles 1102 and 1103; and

i) Warranty: Based on the MTSA between GE and Mesa Power, GE provides a warranty term of [redacted] years on the wind turbines purchased[93]. Thus, there are no unplanned maintenance costs forecast in the Project's [redacted] years of operations.

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[93] Investor's Schedule of Exhibits **C0379** (002023-2.1.2) Amended and Restated Master Turbine Sale Agreement For the Sale of Power Generation Equipment and Related Services [redacted]

4.37 Below is a summary of the operating costs discussed above by project:

	TTD	Arran	Summerhill	North Bruce
Land Royalty	[redacted]	[redacted]	[redacted]	[redacted]
Asset Manager	[redacted]	[redacted]	[redacted]	[redacted]
Planned maintenance 1.6xle/2.5XL (per turbine)	[redacted]	[redacted]	[redacted]	[redacted]
Unplanned maintenance (per turbine)	[redacted]	[redacted]	[redacted]	[redacted]
BOP Maintenance	[redacted]	[redacted]	[redacted]	[redacted]
Transmission Charge	[redacted]	[redacted]	[redacted]	[redacted]
Property Taxes	[redacted]	[redacted]	[redacted]	[redacted]
Insurance	[redacted]	[redacted]	[redacted]	[redacted]
Warranty Term (Yrs)	[redacted]	[redacted]	[redacted]	[redacted]

4.38 In order to test the reasonability of Mesa Power's estimated operating costs, we have considered the operating costs per MWh discussed in industry reports in Schedule 7 (and summarized below) as a benchmark for the Projects' operating costs.

1.6xle turbine			Industry reports			
	Project capacity	Operating costs ($/MWh)	Low	Average	Median	High
TTD	[redacted]	[redacted]	9.00	14.89	15.00	24.00
Arran		[redacted]	9.00	14.89	15.00	24.00
Summerhill	[redacted]	[redacted]	9.00	14.89	15.00	24.00
North Bruce	[redacted]	[redacted]	9.00	14.89	15.00	24.00

4.39 Industry reports suggest that operating costs should be in the range of $9.00 to $24.00 per MWh. The operating costs for Mesa Power's Projects are in the range of the industry benchmarks. Therefore, we have considered the operating costs to be reasonable given that they are within the range of the industry metrics and approximate the median of the industry operating costs per Mwh.

Tax attributes

4.40 We considered the tax attributes available to Mesa Power in our DCF analyses including specific tax incentives available for renewable energy projects. Based on our understanding, the following tax attributes are relevant for our DCF analyses:

a) Capital cost allowance ("CCA") Class 1b: This class relates to costs incurred to purchase or bring buildings into use for the Projects. The costs can be deducted against taxable income on a declining balance basis, to the extent possible, at a rate of 6% and carried forward indefinitely;

b) CCA Class 17: This class relates to costs incurred to construct access roads for the Projects. The costs can be deducted against taxable income on a declining balance basis, to the extent possible, at a rate of 8% and carried forward indefinitely;

c) CCA Class 43.2: This class relates to costs incurred to purchase renewable energy equipment, such as the wind turbines. Balances in this class can be deducted against taxable income on a declining balance basis, to the extent possible, at an accelerated rate of 50% and carried forward indefinitely; and

d) Canadian Renewable Conservation Expenses ("CRCE"): This class relates to costs that generally include intangible expenditures for the pre-production development phase of projects, such as pre-feasibility and feasibility costs, for which equipment is included in CCA class 43.1 or 43.2. Based on our understanding, the development costs incurred and anticipated by Mesa Power would qualify as CRCE and can be fully deducted against taxable income, to the extent possible, and carried forward indefinitely.

Financing

4.41 Based on discussions with Management, we understand that Management had preliminary discussions with various lenders relating to the financing of the Projects. Based on these discussions, the following summarizes the financing terms estimated and reflected for the purpose of our analysis[94]:

a) the debt capacity for the Projects was estimated at 80% of the construction costs;

b) The US Export-Import Bank ("Ex-Im Bank") prepared a letter of intent indicating they were interested in financing Mesa Power's Projects.[95] The financing offer was for 85.0% of the total eligible US content costs of the Projects with an allowance of up to 15.0% foreign content incorporated into the US equipment, support of local costs up to 30.0% of the US contract and [redacted] Based on further discussions with Management, [redacted] The loan was estimated to be amortized over [redacted] and

c) The remaining portion of the financing would have been obtained through a term loan at an interest rate of [redacted] and was also assumed to be amortized over [redacted]

4.42 The aforementioned financing terms are consistent with internal Deloitte's knowledge of financing of renewable energy projects and market research. A Canadian wind farm by Brookfield Renewable Energy Partners obtained bond financing in February 2013 for an amount of $450 million at an interest rate of

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94 Letter from Mesa Power Group to Deloitte LLP, dated November 15, 2013 **C0075**, paragraphs 17 to 19.

95 Investor's Schedule of Exhibits **C0377** (001924) Ex-Im Bank Letter of Interest September 23, 2010.

5.13% for term of 18 years[96]. [redacted]

Discount rate

4.43 For the purpose of our analysis, we have determined a discount rate for each of the Valuation Dates for Articles 1102 and 1103 being January 21 and May 29, 2010. The methodology and each of the components of the discount rates are discussed below.

4.44 One of the most common approaches to estimate an appropriate cost of equity is through the use of the capital asset pricing model ("CAPM").

4.45 The CAPM is based on the theory of portfolio diversification where investors are compensated through increased return for taking on the systematic risk of an investment; risk that cannot be eliminated through diversification. The CAPM estimates the cost of equity based on the following formula:

Cost of Equity = Rf + (ERP * β) + SP + CSRP

4.46 The CAPM relies on observable market inputs to reflect a market based method to estimate an appropriate risk adjusted rate of return. The various elements of the formula are defined as follows:

a) A risk free rate of return ("Rf");

b) A general equity risk premium ("ERP");

c) A measure of the industry specific risk, the beta coefficient ("β");

d) A size premium ("SP"); and,

e) A Company specific risk premium ("CSRP").

4.47 The specific components that are considered in estimating a company's cost of equity using the CAPM are described as follows:

Risk free rate

4.48 The risk-free rate represents the rate of return associated with very low-risk investments. The horizon of the chosen security is based on the likely investment horizon for an investment in the particular asset or shares that are subject to analysis. Accordingly, yields on medium or long-term government bonds are typically used to reflect the risk free rate for a business that is being treated as a going-concern.

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[96] Investor's Schedule of Exhibits **C0238** (004385) KPMG - Wind Energy in Canada: Realizing the Opportunity, dated July 2013.

Equity risk premium

4.49 The equity risk premium represents the additional return an investor expects to receive to compensate for the additional risk associated with investing in equities as opposed to investing in riskless assets. The equity risk premium is essentially the difference between the expected rate of return on the market portfolio and the risk-free rate. The equity risk premium is calculated as the historical return on the market portfolio less the historical risk-free rate of return.

Beta coefficient

4.50 To adjust for the differing risks of particular industries versus the equity market in general, the CAPM uses a multiple of the equity risk premium that reflects the volatility of the return on a stock relative to the stock market in general. This beta factor considers industry specific volatility. Beta describes how the expected return of a stock or portfolio is correlated to the return of the financial market as a whole. By analyzing the beta factors for companies in the same industry, a measure of industry risk can be estimated.

Unsystematic risk factors

4.51 Unsystematic risk factors relate to risks specific to the company or investment in question and are typically categorized as country risks, size risks and company or investment specific risks. A country adjustment factor is typically included to adjust for the differing risks related to an investment in a non-U.S. entity compared to an investment in a U.S. entity. This adjustment is required as the risk free rate, equity risk premium and size premium are all derived from US financial and equity market data while the investment in question would reflect risks associated with an investment in Canada.

4.52 To adjust for the differing risks related to a company's size, the CAPM incorporates a size premium as one element of company or investment specific risk.

4.53 A Company specific risk premium is an expansion to the traditional CAPM and considers the specific risk that may be attributable to a company or investment as a result of size, customer concentration, management depth, key person dependence, forecast risk and other items specific to the company or investment.

4.54 On Schedules 6A and 6B we have calculated the weighted average cost of capital ("WACC") for the Projects. The WACC represents a weighted average of the after-tax cost of debt and after-tax cost of equity. The weighting is based on a company's target debt-equity ratio, measured at market. We determined the WACC for the Projects to be in the range of 5.50% to 5.75% for the Projects, on the basis of the following parameters:

a) an after-tax cost of debt in the order [redacted] based on the weighted average of the expected interest rates for the Projects;

b) a market debt to capital ratio of 80.0% debt and 20.0% equity based on the expected leverage of the Projects;

c) an after-tax cost of equity in the range of 11.5% to 12.5% for the Projects consisting of:

   i. A risk-free rate of 4.38% and 4.05% as at January 21 and May 29, 2010, respectively, based on the 20 year U.S Treasury Constant Maturity Yield;

   ii. A market equity risk premium of 5.75%, which provides an allowance for additional risks, associated with an investment in common shares relative to an investment in government bonds;

   iii. An unlevered beta factor of approximately 0.42, based on the betas of selected publicly-traded companies in the same or similar business as that of the Company. The beta factor is applied to the equity risk premium to reflect the relative risk of the renewable energy industry relative to the entire equity market; and,

   iv. A specific project equity risk premium, which represents the added return that an investor would require for the additional risk of an investment in the Projects, relative to an investment in the overall equity market for comparable industry participants. The specific company equity risk premium was determined on the basis of a judgmental assessment of the risks associated with an investment in the Projects. We have considered a specific risk premium of -1.95% for TTD and Arran and -1.70% for Summerhill and North Bruce, which reflects the following factors:

   – A size premium of 1.85% based on the Ibbotson & Associates Risk Premium report – 2010 Yearbook, Low-Cap (6-8);

   – A country risk adjustment of approximately -0.8% based on Ibbotson & Associates International Cost of Capital (2010);

   – A company specific risk adjustment of -3.0% based on the following:

     - Pursuant to the GEIA, the Government of Ontario was required to facilitate the necessary regulatory approvals and permits;[97] and

     - The price per MWh of the Projects is set at the terms outlined in the FIT Contracts and therefore is stable and predictable whereas it appears that the comparable industry participants do not all have revenue contracts.

   – A risk premium of 0.25% for Summerhill and North Bruce, relative to TTD and Arran given that these projects are at an earlier stage than TTD and Arran and, in particular, do not have a wind study associated thereto, thereby lowering the certainty in respect of production and revenue. However, in respect of the wind studies, it was considered that

[97] Investor's Schedule of Exhibits **C0322** (PH 765) Green Energy Investment Agreement January 21, 2010 (article 7.3a).

Summerhill and North Bruce are in close proximity to TTD and Arran that had wind studies.

4.55 The after-tax cost of equity of 11.50% to 12.50% for the Projects is somewhat conservative in comparison to the Proposed FIT price schedule presentation, dated April 2009 and prepared by the OPA. The presentation outlines the initial valuation assumptions used to determine the pricing structure for the renewable energy projects of which the financing structure expectations include an after-tax return on equity of 11%.[98]

4.56 The forecast reflects cash flow after debt service (principal and interest) and therefore the cash flows as estimated represent the after tax return available to equity investors. While the cash flow as forecast is after debt service, due to the nature of the project financing available, the Projects are not financed at the maximum leverage over their full lives. In the years where the Projects are financed at the maximum leverage [redacted]) the cash flows available to equity investors are discounted using a rate that reflects the estimated after tax return on levered equity. When the Projects are financed at less than the maximum leverage, the return to the equity holders is at less risk due to the reduced financial leverage and therefore equity investors would be willing to accept a lower rate of return, commensurate with the lower risk of the cash flows as forecast.

4.57 As a result, we have estimated the return required by equity holders as a blend of returns on levered equity and debt where the debt component perceived by equity holders is the additional debt required to bring the project to maximum leverage when combined with the level of project financing. As a result, when the project is optimally financed [redacted] the discount rate reflects the estimated after tax return on levered equity. In years when there is no project financing in place (0% debt and 100% equity financing) the discount rate reflects the weighted average cost of capital assuming optimal financing [redacted] considering our understanding that financing would not be available for the development period. With the exception of the development period, the result of this approach is that the aggregate return to the debt and equity investors will in aggregate reflect the WACC for each year of the forecast.

Article 1102 and 1103 – Economic Development Adder

4.58 We have quantified the Economic Losses attributable to the Economic Development Adder offered to the Korean Consortium as part of the Amended GEIA by increasing the starting power price by 0.27 cents per kWh over the base price described above. All other assumptions remain constant and the Economic Losses are determined by calculating the difference between the net present

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[98] Investor's Schedule of Exhibits **C0353** (004355) Proposed Feed-in Tariff Price Schedule, Stakeholder Engagement – Session 4, April 7, 2009, http://fit.powerauthority.on.ca/Storage/10147_FIT_Stakeholder_Engagement_-_Session_4_FIT_Price_Schedule_FINAL_(HP).pdf.

value of the base case for the 1102 and1103 Economic Losses and the net cash flows containing the higher starting power price.

4.59 The total Economic Losses related to the Economic Development Adder are in the range of $20.0 million to $22.0 million as summarized on Schedule 1A.

Article 1102 and 1103 – Capacity Expansion

4.60 We have quantified the Economic Losses attributable to Capacity Expansion for each Project consistent with the Capacity Expansion offered to the Korean Consortium as part of the GEIA. All other assumptions remain constant and the Economic Losses are determined by calculating the difference between the net present value of the base case for 1102 and1103 Economic Losses and the net cash flows containing the additional production capacity. We separately quantified the Economic Losses attributable to the Economic Development Adder related to the Capacity Expansion.

4.61 The total Economic Losses related to the Capacity Expansion are in the range of $33.0 million to $38.0 million as summarized on Schedule 1A. The incremental Economic Losses related to the Economic Development Adder applied to the Capacity Expansion are approximately $2.0 million as summarized on Schedule 1A.

Article 1106 – Performance Requirements

4.62 In order to quantify the Economic Losses under Article 1106, we have prepared a separate forecast that reflects the capital and operating costs related to the Projects if there were no Domestic Content Requirements[99]. We understand that absent the Domestic Content Requirements, Mesa would have used 2.5XL 100 metre wind turbines for the Projects rather than 1.6xle turbines that were projected to be used in order to meet the Domestic Content Requirements. The selection of turbine impacts the revenue and both capital and operating costs.

4.63 The loss related to the Domestic Content Requirements is equal to the difference between the present value of the project cash flows assuming no Domestic Content Requirements (i.e. based on the capital and operating costs related to the 2.5XL turbines) and the cash flow generated by the project assuming compliance with the Domestic Content Requirements (our base model which is based on the capital and operating costs related to the 1.6xle turbines). The forecast reflecting no Domestic Content Requirements includes the following changes to the assumptions / inputs in the base forecast as set out for Articles 1102 and 1103 above:

a) The average annual energy production is calculated based on the 2.5XL 100M wind turbine as summarized above;

[99] For the purpose of the net present value calculations for Article 1106, we have used the same discount rate for Arran and TTD as in our Articles 1102 and 1103 analysis given that there were no significant changes in the Projects and the WACC between November 25, 2009 and January 21, 2010.

b) The construction costs related to the 2.5XL 100M wind turbine scenario[100];;

c) Based on information provided by Mortensen, we understand the EPC pricing would also increase to meet the Domestic Content Requirements[101]. EPC pricing would have increased by approximately [redacted] adjusted for the relative number of turbine for each Project compared to the sample wind farm quote by Mortensen. Such increase in costs relate to the configuration and tracking of materials, pad mount transformer, main power transformer, management and supervision labour and general labour; and

d) Several operating costs differ as they are estimated on a per turbine basis and the 2.5XL scenario requires fewer turbines.

4.64 Based on the assumption that Mesa Power would have also received the Economic Development Adder and Capacity Expansion, we have quantified the additional Economic Losses related to Domestic Content Requirements are approximately $1.0 million related to the Economic Development Adder, $9.0 million to $10.0 million related to the Capacity Expansion and $0.2 million to $0.3 million related to the Economic Development Adder applicable to the Capacity Expansion.

4.65 The total Economic Losses related to the Domestic Content Requirements are in the range of $101.2 million to $111.3 million as summarized on Schedule 1A.

Article 1105 – Minimum Standard of Treatment

4.66 In order to quantify the Economic Losses under Article 1105, we have included the following Economic Losses as discussed above:

a) Economic Losses related to the Base Case scenario of $303.0 million to $345.0 million;

b) Economic Losses related to the Economic Development Adder of $20.0 million to $22.0 million;

c) Economic Losses related to the Capacity Expansion of $33.0 million to $38.0 million;

d) Economic Losses related to the Economic Development Adder applied to the Capacity Expansion of $2.0 million;

e) Past development costs incurred related to the Projects of $8.1 million;

f) The GE deposit forfeited of $156.8 million; and,

g) The Economic Losses related to the Domestic Content Requirements of $101.2 million to $111.3 million.

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[100] Letter from Mesa Power Group to Deloitte LLP, dated November 15, 2013 **C0075**, paragraph 7.

[101] Investor's Schedule of Exhibits **C0206** (004341) Mortensen Ontario Wind Project with Domestic Content Requirements

Market approach

4.67 In order to assess the reasonableness of the conclusions determined for each of the Projects, we have considered value relationships implied by selected market transactions involving the sale of similar projects. We recognize the limitations in directly applying transaction references in the context of the Projects due to the different geographic areas served, Domestic Content Requirements, terms of power pricing agreements, wind and project size. This approach represents solely a reasonability test.

4.68 Notwithstanding the above, we believe it is relevant to consider implied transaction references in assessing the overall conclusions as to the Economic Losses related to the Projects.

4.69 In order to identify comparable projects we restricted our search to wind farms that were:

a) in North America,
b) on-shore; and,
c) are in late-stage development.

4.70 We classified comparable projects as early-stage, late-stage, under construction or installed based on the following assumptions:

Early-stage pipeline	Late-stage pipeline	Under construction	Installed
• Site feasibility study • Initial wind data collection • Building and grid connection permit application • Geological studies • Concession rights • Community engagement • Land agreements	• Full study of site and wind characteristics • Obtaining approvals • Reservation payments for turbines, cables, etc. • Applying for debt financing • Reaching a power purchase agreement. •	• Constructing and installation of towers, turbines and cables • Financial close •	• Operation and maintenance •

4.71 Given the assumption that the Projects would have each benefited from the rights and privileges conveyed by the GEIA including the facilitation commitments of the province and received a FIT Contract, the Projects would be more comparable to late-stage projects. Further, it is our view that the rights and privileges of the GEIA reduced the risks related to the Projects and accordingly increased their value relative to the projects below.

4.72 Based on the above noted criteria, we have considered five somewhat comparable projects. Based on information related to the comparable transactions we have calculated value metrics implied in the transactions that can be compared to the same value metric implied by our conclusion as to value for each of the Projects.

Project	Country	Stage	Capacity	Implied late-stage price multiple ($million/MW)
Midwest Renewable	USA	Early & Late-stage	120MW in early stage 400MW in late-stage	0.11x
Project Wildmare, Bullmoose, Tumbler Ridge, and Meikle	Canada	Late-stage	300MW in late-stage	0.13x
Dokie Wind	Canada	Late-stage	156MW in late-stage	0.32x
EverPower Wind Holding	USA	Late-stage	821 in late-stage	0.30x
Butter Creek	USA	Late-stage	40MW in late-stage	0.96x
Minimum				**0.11x**
Median				**0.30x**
Average				**0.36x**
Maximum				**0.96x**
Implied multiples – 1.6xle				
TTD				[redacted]
Arran				[redacted]
Summerhill				[redacted]
North Bruce				[redacted]

4.73 The intrinsic value of the Projects is appropriately higher than the implied average value based on the comparable projects based on the following:

a) The power prices offered in the FIT Contracts in Ontario were believed to be higher than other regions in North America and therefore the profitability per MW of the Projects is higher and an investor would be willing to pay more for the same level of production;

b) Our analysis was based on the guarantees provided by the GEIA and the Amended GEIA;

c) Mesa Power had a MTSA which guaranteed the availability of wind turbines that would meet Domestic Content Requirements; and

d) Not all projects within the comparable transaction set had a power purchase agreement similar to a FIT Contract which guaranteed a certain future stream.

Economic Losses conclusion

4.74 Based on the scope of our review (Appendix A), assumptions (Appendix B) and our research, analysis and experience, our opinion of the Economic Losses for the Period of Loss is summarized below. If requested to select a single point estimate of the Economic Losses, we would suggest the midpoint of the range of $624.1 million to $683.2 million (NAFTA 1102/1103/1105), or $653.7 million, set out below. The Economic Losses related to Article 1106 while separately determined as $101.2 million to $111.3 million, with a midpoint of $106.3 million, are included in the Economic Losses for Articles 1102, 1103 and 1105, and are not additive thereto.

4.75 The methodology above results in an after-tax capital value for the components other than past costs and the GE contract penalty. Since these Economic Losses for 1102, 1103, 1105 and 1106 represent income to be earned in the future, it is our view that an award inclusive of these amounts will be taxable as income to the Company. Accordingly, we have grossed-up the after-tax amounts to pre-tax amounts, such that after paying the tax upon receipt, Mesa Power will be made whole. Mesa will have the after-tax cash amount that it would have had if the Projects had been completed.

4.76 The Economic Losses presented herein exclude any consideration for pre-judgment and post-judgment interest, as well as any legal or other fees incurred by the Plaintiffs in this matter.

CAD 000s	Low	High
NAFTA 1102/1103/1105		
Base Case	303,000	345,000
Economic Development Adder	20,000	22,000
Capacity Expansion	33,000	38,000
Economic Development Adder applicable to Capacity Expansion	2,000	2,000
Past costs incurred	8,100	8,100
General Electric deposit forfeited	156,833	156,833
NAFTA 1106 (below)		111,300
Total NAFTA 1102/1103/1105	**624,133**	**683,233**
NAFTA 1106		
Base Case	91,000	100,000
Economic Development Adder	1,000	1,000
Capacity Expansion	9,000	10,000
Economic Development Adder applicable to Capacity Expansion	200	300
Total NAFTA 1106	**101,200**	**111,300**

Schedules

Schedule 1A
Summary
Amounts in 000's CAD unless otherwise stated

	Notes	Economic Losses		
		Low	Midpoint	High
NAFTA 1102, 1103 & 1105				
Base Case				
Twenty-two degrees	**[F1]**	93,360	99,400	105,440
Arran	**[F2]**	57,100	61,125	65,150
Summerhill	**[F3]**	56,340	60,200	64,060
North Bruce	**[F4]**	96,070	102,995	109,920
Total (rounded)		303,000	324,000	345,000
Economic Development Adder ("EDA")				
Twenty-two degrees	**[F1]**	5,630	5,875	6,120
Arran	**[F2]**	4,100	4,275	4,450
Summerhill	**[F3]**	3,540	3,700	3,860
North Bruce	**[F4]**	6,900	7,215	7,530
Total (rounded)		20,000	21,000	22,000
Capacity Expansion				
Twenty-two degrees	**[F1]**	10,380	11,025	11,670
Arran	**[F2]**	6,590	7,025	7,460
Summerhill	**[F3]**	6,450	6,860	7,270
North Bruce	**[F4]**	9,800	10,505	11,210
Total (rounded)		33,000	35,500	38,000
EDA applicable to capacity expansion				
Twenty-two degrees	**[F1]**	510	535	560
Arran	**[F2]**	410	430	450
Summerhill	**[F3]**	340	355	370
North Bruce	**[F4]**	600	625	650
Total (rounded)		2,000	2,000	2,000
Past costs incurred	**[F5]**	8,100	8,100	8,100
GE contract penalty	**[F6]**	156,833	156,833	156,833
NAFTA 1106		101,200	106,250	111,300
Total Economic Losses under NAFTA Article 1102, 1103 & 1105	**[F7]**	**624,133**	**653,683**	**683,233**

Schedule 1A
Summary
Amounts in 000's CAD unless otherwise stated

	Notes	Economic Losses		
		Low	Midpoint	High
NAFTA 1106				
Base Case				
Twenty-two degrees	[F1]	15,670	16,475	17,280
Arran	[F2]	21,730	22,725	23,720
Summerhill	[F3]	10,640	11,120	11,600
North Bruce	[F4]	43,400	45,380	47,360
Total (rounded)		91,000	95,500	100,000
EDA				
Twenty-two degrees	[F1]	260	270	280
Arran	[F2]	270	280	290
Summerhill	[F3]	20	25	30
North Bruce	[F4]	300	315	330
Total (rounded)		1,000	1,000	1,000
Capacity Expansion				
Twenty-two degrees	[F1]	1,680	1,760	1,840
Arran	[F2]	970	1,020	1,070
Summerhill	[F3]	1,060	1,115	1,170
North Bruce	[F4]	4,980	5,200	5,420
Total (rounded)		9,000	9,500	10,000
EDA applicable to capacity expansion				
Twenty-two degrees	[F1]	80	80	80
Arran	[F2]	30	30	30
Summerhill	[F3]	10	15	20
North Bruce	[F4]	120	130	140
Total (rounded)		200	250	300
Total Economic Losses under NAFTA Article 1106	[F7]	**101,200**	**106,250**	**111,300**

Schedule 1A
Summary
Amounts in 000's CAD unless otherwise stated

Notes

[F1] See TTD analysis, Schedules 2A - 2M.
[F2] See Arran analysis, Schedules 3A - 3M.
[F3] See Summerhill analysis, Schedules 4A - 4M.
[F4] See North Bruce analysis, Schedules 5A - 5M.
[F5] Costs incurred by Mesa Power in relation to preparing the projects for commercial operation. Although these costs would have been incurred to achieve profits, we have added the past costs to the losses determined in 1102 and 1103 as they have been deducted in determining the lost profits in the base case and they were incurred by Mesa Power and therefore cannot be avoided. Please refer to Schedule 1B for details.
[F6] Downpayment paid to GE for all wind projects. Investor's Schedule of Exhibits **C0381** (002111).

Amount paid (USD)	153,593
USD:CAD FX rate	1.0211
Amount paid (CAD)	156,833

[F7] Please refer to Sections 1.12 to 1.27 for further details related to the claims.

Schedule 1B
Project Twenty-Two Degrees
Summary of Past Costs
Amounts in CAD unless otherwise stated

	Notes	TTD	AWA - TTD [F1]	Arran	AWA - Arran [F1]	North Bruce	AWA - North [F1]	Summerhill	AWA - Summerhill [F1]	Total
Expense item		[redacted]								
Accounting expense										
Acquisition costs	**[F2]**									
Bank service charges										
Computing/software expense										
Consulting fees										
Gain/loss - HST exchange rate										
GST refund										
Land lease expense										
Lobbying expense										
Maintenance Exp.- Met Towers										
Marketing expense										
Meeting expense										
Miscellaneous expense										
Postage and delivery										
Property tax expense										
Office supplies										
Registration fees										
Start-up legal expense										
Start-up project development expense										
Tax expense										
Wind Equipment- Met Towers	**[F2]**									
Total nominal past costs										
Total inflated past costs (000s)										

Notes:
[F1] We have considered the expenses incurred by each project as well as the expenses incurred by AWA that were attributed to one of the projects.
[F2] These expenses were capitalized for accounting purposes but have been included as past costs as they are cash outflows paid to develop the projects.

Schedule 2A
Project Twenty-Two Degrees
Summary
Amounts in 000's CAD unless otherwise stated

	Notes		Economic Losses		
			Low	Midpoint	High
NAFTA 1102, NAFTA 1103 & NAFTA 1105	**[F1]**				
Base Case		**Schedule 2B**	93,360	99,402	105,444
Economic Development Adder		**Schedule 2C**	5,631	5,875	6,120
Capacity expansion		**Schedule 2D**	10,382	11,025	11,669
Economic Development Adder applicable to capacity expansion		**Schedule 2D**	511	533	555
NAFTA 1106			17,683	18,581	19,478
Total			127,565	135,416	143,266
NAFTA 1106					
Base Case		**Schedule 2E**	15,673	16,475	17,276
Economic Development Adder		**Schedule 2F**	256	267	278
Capacity expansion		**Schedule 2G**	1,676	1,759	1,841
Economic Development Adder applicable to capacity expansion			77	80	83
Total			17,683	18,581	19,478
Total claim (pre-tax)			**127,565**	**135,416**	**143,266**
Total claim, rounded			**128,000**	**135,000**	**143,000**

Notes

[F1] Please refer to Sections 1.12 to 1.27 for further details related to the claims.

Schedule 2B
Project Twenty-Two Degrees
Discounted Cash Flows - NAFTA Article 1102, 1103 & 1105 (Base Case)
Amounts in CAD 000's unless otherwise stated
As at January 21, 2010

					pre-Jan 21	post Jan 21			For the year ended December 31,								
	Notes		2008	2009	2010	2010	2011	2012	2013	2014	2015	2020	2021	2022	2032	2033	2034
Revenue			[redacted]														
Price	[F1]	0.42%															
Production (000s MWh)	[F2]																
Total revenue																	
Operating expenses	[F3]																
Land Payments (2.7% of revenue)		2.20%															
Asset manager	[F4]																
Unplanned maintenance	[F4]																
Planned maintenance	[F4]																
Transmission charge	[F4]																
BOP maintenance	[F4]																
Property taxes	[F4]																
Insurance	[F4]																
Total operating expenses																	
EBITDA																	
Less: Interest expense																	
EX-IM loan interest	[F5]																
Term loan interest	[F5]																
Net cash flows after interest																	
Less: Taxes @ 25.00%	[F6]																
After-tax cash flow																	
Less: Debt principal repayments																	
EX-IM loan principal payment	[F7]																
Term loan principal payment	[F7]																
Levered free cash flows																	
LOW																	
Percent of year remaining																	
Discounting period																	
Discount rate																	
Cumulative PV factor																	
Discounted operating cash flows																	
Equity-financed capital expenditures		[F8]															
NPV of cash flows		[redacted]															
Gross pre-tax NPV of cash flows																	
HIGH																	
Discount rate																	
Cumulative PV factor																	
Discounted operating cash flows																	
Equity-financed capital expenditures																	
NPV of cash flows																	
Gross pre-tax NPV of cash flows																	

Notes

[F1] Power price based on FIT application.
[F2] Annual energy production based on the project's wind study. Investor’s Schedule of Exhibits **C0378** (001971).
[F3] We have tested the reasonability of total operating expenses with comparable project benchmark data. See Schedule 7 for fur her details. Based on our research, total operating expenses were determined to be reasonable.
[F4] We have assumed hat these expenses would increase annually by 2.2%, based on infla ion forecasts from Economic Intelligence Unit.
[F5] Schedule 2H.
[F6] Tax rates are based on the substantively enacted tax rates as at the Valuation Date.

Tax expense:

			2008	2009	2010 pre-Jan 21	2010 post Jan 21	2011	2012	2013	2014	2015	2020	2021	2022	2032	2033	2034
Net cash flows after interest	**[A]**		[redacted]														
Less: tax deductions	**[B]**																
Taxable income	**[A] + [B]**																
Tax expense		25.00%															

[B] The tax deductions/adjustments are quantified by considering the tax attributes available for renewable energy projects. Specifically, we have considered capital cost allowances and Canadian Renewable Conservation Expenses.

[F7] Schedule 2H.
[F8] Schedule 2J.
[F9] For presentation purposes, we have ommited he visibility of certain years of the forecast.

Schedule 2C
Project Twenty-Two Degrees
Discounted Cash Flows - NAFTA Article 1102, 1103 & 1105 (Economic Development Adder)
Amounts in CAD 000's unless otherwise stated
As at January 21, 2010

	Notes		pre-Jan 21			post Jan 21		For the year ended December 31,								
			2008	2009	2010	2010	2011	2012	2013	2014	2015	2020	2021	2022	2032	2033	2034
Revenue																	
Price	[F1]	0.42%	[redacted]														
Production (000s MWh)	[F2]																
Total revenue																	
Operating expenses	[F3]																
Land Payments [redacted]		2.20%															
Asset manager	[F4]																
Unplanned maintenance	[F4]																
Planned maintenance	[F4]																
Transmission charge	[F4]																
BOP maintenance	[F4]																
Property taxes	[F4]																
Insurance	[F4]																
Total operating expenses																	
EBITDA																	
Less: Interest expense																	
EX-IM loan interest	[F5]																
Term loan interest	[F5]																
Net cash flows after interest																	
Less: Taxes @ 25.00%	[F6]																
After-tax cash flow																	
Less: Debt principal repayments																	
EX-IM loan principal payment	[F7]																
Term loan principal payment	[F7]																
Levered free cash flows																	
LOW																	
Percent of year remaining			[redacted]														
Discounting period																	
Discount rate																	
Cumula ive PV factor																	
Discounted operating cash flows																	
Equity-financed capital expenditures		[F8]															
Net present value of cash flows		[redacted]															
Less: NAFTA 1102/1103/1105 - Base Case	[F9]																
NPV of incremental cash flows																	
Gross pre-tax NPV of incremental cash flows																	
HIGH																	
Discount rate						11.5%	11.5%	11.5%	11.5%	11.3%	11.1%	9.9%	9.6%	9.3%	5.5%	5.5%	5.5%
Cumula ive PV factor						0.95	0.85	0.77	0.69	0.62	0.56	0.34	0 31	0.28	0.14	0.13	0.13
Discounted operating cash flows			**-**	**-**	**-**	**-**	**-**	**-**	**-**	**10,748**	**15,770**	**9,074**	**7,907**	**6,038**	**4,338**	**4,799**	**1,529**
Equity-financed capital expenditures			**(579)**	**(859)**	**(49)**	**(151)**	**(418)**	**(283)**	**(17,656)**	**(33,107)**	**-**	**-**	**-**	**-**	**-**	**-**	**-**
Net present value of cash flows			**(579)**	**(859)**	**(49)**	**(151)**	**(418)**	**(283)**	**(17,656)**	**(22,360)**	**15,770**	**9,074**	**7,907**	**6,038**	**4,338**	**4,799**	**1,529**
Less: NAFTA 1102/1103/1105 - Base Case	[F9]																
NPV of incremental cash flows																	
Gross pre-tax NPV of incremental cash flows																	

Notes:

[F1] Power price based on FIT application. In this scenario we have added the Economic Development Adder of 0.27 cents per kWh that was offered to Samsung in the Amended GEIA. Investor's Schedule of Exhibits **C0282** (4403).

[F2] Annual energy production based on the project's wind study. Investor's Schedule of Exhibits **C0378** (001971).

[F3] We have tested the reasonability of total operating expenses with comparable project benchmark data. See Schedule 7 for further details. Based on our research, total operating expenses were determined to be reasonable.

[F4] We have assumed that these expenses would increase annually by 2.2%, based on inflation forecasts from Economic Intelligence Unit.

[F5] Schedule 2H.

[F6] Tax rates are based on the substantively enacted tax rates as at the Valua ion Date.

Tax expense:

					pre-Jan 21	post Jan 21											
			2008	**2009**	**2010**	**2010**	**2011**	**2012**	**2013**	**2014**	**2015**	**2020**	**2021**	**2022**	**2032**	**2033**	**2034**
Net cash flows after interest	**[A]**		[redacted]														
Less: tax deductions	**[B]**																
Taxable income	**[A] + [B]**																
Tax expense		25.00%															

[B] The tax deduc ions/adjustments are quantified by considering the tax attributes available for renewable energy projects. Specifically, we have considered capital cost allowances and Canadian Renewable Conservation Expenses.

[F7] Schedule 2H.

[F8] Schedule 2J.

[F9] Schedule 2B.

[F10] For presentation purposes, we have ommited the visibility of certain years of the forecast.

Schedule 2D
Project Twenty-Two Degrees
Discounted Cash Flows - NAFTA Article 1102, 1103 & 1105 (Capacity Expansion)
Amounts in CAD 000's unless otherwise stated
As at January 21, 2010

					pre-Jan 21	post Jan 21				For the year ended December 31,							
	Notes		2008	2009	2010	2010	2011	2012	2013	2014	2015	2020	2021	2022	2032	2033	2034
Revenue																	
Price	[F1]	0.42%								142.40	142.99	145.99	146.59	147.20	153.42	154.06	154.70
Production (000s MWh)	[F2]		[redacted]														
Total revenue																	
Operating expenses	[F3]																
Land Payments [redacted]		2.20%															
Asset manager	[F4]																
Unplanned maintenance	[F4]																
Planned maintenance	[F4]																
Transmission charge	[F4]																
BOP maintenance	[F4]																
Property taxes	[F4]																
Insurance	[F4]																
Total operating expenses																	
EBITDA																	
Less: Interest expense																	
EX-IM loan interest	[F5]																
Term loan interest	[F5]																
Net cash flows after interest																	
Less: Taxes @ 25.00%	[F6]																
After-tax cash flow																	
Less: Capital expenditures																	
Less: Debt principal repayments																	
EX-IM loan principal payment	[F5]																
Term loan principal payment	[F5]																
Levered free cash flows																	
LOW																	
Percent of year remaining						94%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%
Discounting period			[redacted]														
Discount rate																	
Cumulative PV factor																	
Discounted operating cash flows																	
Equity-financed capital expenditures	[F7]	[redacted]															
Net present value of cash flows																	
Less: NAFTA 1102/1103/1105 - Base Case	[F8]																
NPV of incremental cash flows																	
Gross pre-tax NPV of incremental cash flows																	
Including Economic Development Adder																	
NPV of EDA on capacity expansion	[F9]																
Less: NAFTA 1102/1103/1105 - EDA	[F10]																
NPV of incremental cash flows																	
Gross pre-tax NPV of incremental cash flows																	

Schedule 2D
Project Twenty-Two Degrees
Discounted Cash Flows - NAFTA Article 1102, 1103 & 1105 (Capacity Expansion)
Amounts in CAD 000's unless otherwise stated
As at January 21, 2010

			pre-Jan 21			post Jan 21	For the year ended December 31,										
	Notes		2008	2009	2010	2010	2011	2012	2013	2014	2015	2020	2021	2022	2032	2033	2034
HIGH																	
Discount rate			[redacted]														
Cumulative PV factor																	
Discounted operating cash flows																	
Equity-financed capital expenditures	**[F7]**																
Net present value of cash flows		[redacted]															
Less: NAFTA 1102/1103/1105 - Base Case	**[F8]**																
NPV of incremental cash flows																	
Gross pre-tax NPV of incremental cash flows																	
Including Economic Development Adder																	
NPV of EDA on capacity expansion	**[F9]**																
Less: NAFTA 1102/1103/1105 - EDA	**[F10]**																
NPV of incremental cash flows																	
Gross pre-tax NPV of incremental cash flows																	

Notes:

[F1] Power price based on FIT application. In this scenario we have added the Economic Development Adder of 0.27 cents per kWh that was offered to Samsung in the Amended GEIA. Investor's Schedule of Exhibits **C0282** (4403).
[F2] Annual energy production based on the project's wind study. Investor's Schedule of Exhibits **C0378** (001971).
[F3] We have tested the reasonability of total operating expenses with comparable project benchmark data. See Schedule 7 for fur her details. Based on our research, total opera ing expenses were determined to be reasonable.
[F4] Assumed to be a fixed cost and therefore does not increase with he increase in capacity.
[F5] Schedule 2H.
[F6] Tax rates are based on the substantively enacted tax rates as at the Valuation Date.
Tax expense:

			pre-Jan 21			post Jan 21											
			2008	2009	2010	2010	2011	2012	2013	2014	2015	2020	2021	2022	2032	2033	2034
Net cash flows after interest	**[A]**		[redacted]														
Less: tax deductions	**[B]**																
Taxable income	**[A] + [B]**																
Tax expense		25.00%															

[B] The tax deductions/adjustments are quantified by considering the tax attributes available for renewable energy projects. Specifically, we have considered capital cost allowances and Canadian Renewable Conservation Expenses.
[F7] Schedule 2K.
[F8] Schedule 2B.
[F9] We have calculated he additional Economic Losses related to the Economic Development Adder on the 10% capacity expansion by increasing the price (as used in Schedule 2C). The operating, capital and financing costs remain the same.
[F10] Schedule 2C.
[F11] For presentation purposes, we have ommited he visibility of certain years of the forecast.

Schedule 2E
Project Twenty-Two Degrees
Discounted Cash Flows - NAFTA Article 1106 (Base Case)
Amounts in CAD 000's unless otherwise stated
As at November 25, 2009

	Notes		post Nov 25 2009	2010	2011	2012	2013	2014	2015	2020	2021	2022	2031	2032	2033	2034
			For the year ended December 31,													
Revenue																
Price	[F1]	0.42%	[redacted]													
Production (000s MWh)	[F2]															
Total revenue																
Operating expenses	[F3]															
Land Payments [redacted]		2.20%														
Asset manager	[F4]															
Unplanned maintenance	[F4]															
Planned maintenance	[F4]															
Transmission charge	[F4]															
BOP maintenance	[F4]															
Property taxes	[F4]															
Insurance	[F4]															
Total operating expenses																
EBITDA																
Less: Interest expense																
EX-IM loan interest	[F5]															
Term loan interest	[F5]															
Net cash flows after interest																
Less: Taxes @ 25.00%	[F6]															
After-tax cash flow																
Less: Debt principal repayments																
EX-IM loan principal payment	[F5]															
Term loan principal payment	[F5]															
Levered free cash flows																
NAFTA Article 1106 - Base Case																
NAFTA Article 1102/1103/1105 - Base Case	[F7]															
Incremental levered free cash flows																
LOW																
Percent of year remaining			[redacted]													
Discounting period																
Discount rate																
Cumulative PV factor																
Discounted incremental operating cash flows																
Incremental equity-financed capital expenditures		[F8]														
NPV of incremental cash flows		[redacted]														
Gross pre-tax NPV of cash flows																
HIGH																
Discount rate																
Cumulative PV factor																
Discounted operating cash flows																
Equity-financed capital expenditures																
Net present value of cash flows																
Gross pre-tax NPV of cash flows																

Notes:

[F1] Power price based on FIT application.
[F2] Annual energy production based on the project's wind study. Investor’s Schedule of Exhibits **C0378** (001971).
[F3] We have tested the reasonability of total operating expenses with comparable project benchmark data. See Schedule 7 for fur her details. Based on our research, total opera ing expenses were determined to be reasonable.
[F4] We have assumed hat these expenses would increase annually by 2.2%, based on infla ion forecasts from Economic Intelligence Unit.
[F5] Schedule 2I.
[F6] Tax rates are based on the substantively enacted tax rates as at the Valuation Date.

Tax expense:

			post Nov 25 2009	2010	2011	2012	2013	2014	2015	2020	2021	2022	2031	2032	2033	2034
Net cash flows after interest	**[A]**		[redacted]													
Less: tax deductions	**[B]**															
Taxable income	**[A] + [B]**															
Tax expense		25.00%														

[B] The tax deductions/adjustments are quantified by considering the tax attributes available for renewable energy projects. Specifically, we have considered capital cost allowances and Canadian Renewable Conservation Expenses.

[F7] Schedule 2B.
[F8] Schedule 2L.
[F9] For presentation purposes, we have ommited the visibility of certain years of the forecast.

Schedule 2F
Project Twenty-Two Degrees
Discounted Cash Flows - NAFTA Article 1106 (Economic Development Adder)
Amounts in CAD 000's unless otherwise stated
As at November 25, 2009

	Notes		post Nov 25	For the year ended December 31,												
			2009	2010	2011	2012	2013	2014	2015	2020	2021	2022	2031	2032	2033	2034
Revenue																
Price	[F1]	0.42%						145.10	145.69	148.69	149 29	149 90	155.49	156.12	156.76	157.40
Production (000s MWh)	[F2]		[redacted]													
Total revenue																
Operating expenses	[F3]															
Land Payments [redacted]		2.20%														
Asset manager	[F4]															
Unplanned maintenance	[F4]															
Planned maintenance	[F4]															
Transmission charge	[F4]															
BOP maintenance	[F4]															
Property taxes	[F4]															
Insurance	[F4]															
Total operating expenses																
EBITDA																
Less Interest expense																
EX-IM loan interest	[F5]															
Term loan interest	[F5]															
Net cash flows after interest																
Less: Taxes @ 25.00%	[F6]															
After-tax cash flow																
Less Debt principal repayments																
EX-IM loan principal payment	[F5]															
Term loan principal payment	[F5]															
Levered free cash flows																
NAFTA Article 1106 - EDA																
NAFTA Article 1106 - Base Case	[F7]															
Incremental levered free cash flows																
LOW																
Percent of year remaining																
Discounting period																
Discount rate																
Cumulative PV factor																
Discounted incremental operating cash flows																
Net present value of incremental cash flows		[redacted]														
Less: NPV NAFTA 1102/1103/1105 - EDA	[F8]															
NPV of incremental cash flows																
Gross pre-tax NPV of incremental cash flows																
HIGH																
Discount rate																
Cumulative PV factor																
Discounted operating cash flows																
Net present value of cash flows																
Less: NPV NAFTA 1102/1103/1105 - EDA	[F8]															
NPV of incremental cash flows																
Gross pre-tax NPV of incremental cash flows																

Notes

[F1] Power price based on FIT application. In this scenario we have added the Economic Development Adder of 0.27 cents per kWh that was offered to Samsung in the Amended GEIA. Investor's Schedule of Exhibits **C0282** (4403).

[F2] Annual energy production based on the project's wind study. Investor's Schedule of Exhibits **C0378** (001971).

[F3] We have tested the reasonability of total operating expenses with comparable project benchmark data. See Schedule 7 for further details. Based on our research, total operating expenses were determined to be reasonable.

[F4] We have assumed that these expenses would increase annually by 2.2%, based on inflation forecasts from Economic Intelligence Unit.

[F5] Schedule 2I.

[F6] Tax rates are based on the substantively enacted tax rates as at the Valuation Date.

Tax expense:

			post Nov 25 2009	2010	2011	2012	2013	2014	2015	2020	2021	2022	2031	2032	2033	2034
Net cash flows after interest	**[A]**		[redacted]													
Less: tax deductions	**[B]**															
Taxable income	**[A] + [B]**															
Tax expense		25.00%														

[B] The tax deductions/adjustments are quantified by considering the tax attributes available for renewable energy projects. Specifically, we have considered capital cost allowances and Canadian Renewable Conservation Expenses.

[F7] Schedule 2E.

[F8] Schedule 2C has been discounted to reflect the Valuation Date for the NAFTA 1106 claim:

		Low	High	
NAFTA Article 1102/1103/1105 - EDA	**Schedule 2C**	[redacted]		as at Jan. 21, 2010
Discount factor adjustment		0.982	0.983	
NAFTA Article 1102/1103/1105 - EDA		[redacted]		as at Nov. 25, 2009

[F9] For presentation purposes, we have ommited the visibility of certain years of the forecast.

Schedule 2G
Project Twenty-Two Degrees
Discounted Cash Flows - NAFTA Article 1106 (Capacity Expansion)
Amounts in CAD 000's unless otherwise stated
As at November 25, 2009

	Notes		For the year ended December 31, 2012	2013	2014	2015	2020	2021	2022	2031	2032	2033	2034
Revenue													
Price	[F1]	0.42%	[redacted]										
Production (000s MWh)	[F2]												
Total revenue													
Operating expenses	[F3]												
Land Payments (2.7% of revenue)		2.20%											
Asset manager	[F4]												
Unplanned maintenance	[F4]												
Planned maintenance	[F4]												
Transmission charge	[F4]												
BOP maintenance	[F4]												
Property taxes	[F4]												
Insurance	[F4]												
Total operating expenses													
EBITDA													
Less: Interest expense													
EX-IM loan interest	[F5]												
Term loan interest	[F5]												
Net cash flows after interest													
Less: Taxes @ 25.00%	[F6]												
After-tax cash flow													
Less: Debt principal repayments													
EX-IM loan principal payment	[F5]												
Term loan principal payment	[F5]												
Levered free cash flows													
NAFTA Article 1106 - Capacity Expansion													
NAFTA Article 1106 - Base Case	[F8]												
Incremental levered free cash flows													
LOW													
Percent of year remaining													
Discounting period													
Discount rate													
Cumulative PV factor													
Discounted incremental operating cash flows													
Incremental equity-financed capital expenditures	[F9]												
NPV of incremental cash flows													
Less: NPV NAFTA 1102/1103/1105 - Capacity Expansion	[F10]												
NPV of incremental cash flows													
Gross pre-tax NPV of incremental cash flows													
Including Economic Development Adder													
NPV of EDA on capacity expansion	[F7]												
Less: NAFTA 1102/1103/1105 - Capacity Expansion with EDA	[F10]												
NPV of incremental cash flows													
Gross pre-tax NPV of incremental cash flows													

Schedule 2G
Project Twenty-Two Degrees
Discounted Cash Flows - NAFTA Article 1106 (Capacity Expansion)
Amounts in CAD 000's unless otherwise stated
As at November 25, 2009

	Notes		For the year ended December 31,										
			2012	2013	2014	2015	2020	2021	2022	2031	2032	2033	2034
HIGH													
Discount rate			[redacted]										
Cumulative PV factor													
Discounted operating cash flows													
Equity-financed capital expenditures	**[F9]**												
Net present value of cash flows													
Less: NAFTA 1102/1103/1105 - Capacity Expansion	**[F10]**												
NPV of incremental cash flows													
Gross pre-tax NPV of incremental cash flows													
Including Economic Development Adder													
NPV of EDA on capacity expansion	**[F7]**												
Less: NAFTA 1102/1103/1105 - Capacity Expansion with EDA	**[F10]**												
NPV of incremental cash flows													
Gross pre-tax NPV of incremental cash flows													

Notes:

[F1] Power price based on FIT application. In this scenario we have added he Economic Development Adder of 0.27 cents per kWh hat was offered to Samsung in the Amended GEIA. Investor's Schedule of Exhibits **C0282** (4403).
[F2] Annual energy production based on the project's wind study. Investor's Schedule of Exhibits **C0378** (001971).
[F3] We have tested the reasonability of total operating expenses with comparable project benchmark data. See Schedule 7 for further details. Based on our research, total operating expenses were determined
[F4] We have assumed that these expenses would increase annually by 2.2%, based on inflation forecasts from Economic Intelligence Unit.
[F5] Schedule 2I
[F6] Tax rates are based on the substantively enacted tax rates as at the Valuation Date.
Tax expense:

			2012	2013	2014	2015	2020	2021	2022	2031	2032	2033	2034
Net cash flows after interest	**[A]**		[redacted]										
Less: tax deductions	**[B]**												
Taxable income	**[A] + [B]**												
Tax expense		25.00%											

[B] The tax deductions/adjustments are quantified by considering the tax attributes available for renewable energy projects. Specifically, we have considered capital cost allowances and Canadian Renewable Conservation Expenses.

[F7] We have calculated the additional Economic Losses related to the Economic Development Adder on the 10% capacity expansion by increasing the price (as used in Schedule 2F). The operating, capital and financing costs remain the same.

[F8] Schedule 2E.
[F9] Schedule 2M.
[F10] Schedule 2D has been discounted to reflect the Valua ion Date for the NAFTA 1106 claim:

		Low	High	
NAFTA Article 1102/1103/1105 - Capacity Expansion	**Schedule 2D**	[redacted]		as at Jan. 21, 2010
Discount factor adjustment		0.982	0.983	
NPV of base case (NAFTA Article 1102/1103/1105 - Capacity Expansion)		[redacted]		as at Nov. 25, 2009
NAFTA Article 1102/1103/1105 - Capacity Expansion including EDA	**Schedule 2D**			as at Jan. 21, 2010
Discount factor adjustment		0.982	0.983	
NAFTA Article 1102/1103/1105 - Capacity Expansion including EDA		[redacted]		as at Nov. 25, 2009

[F11] For presenta ion purposes, we have ommited the visibility of certain years of the forecast.

Schedule 2H
Project Twenty-Two Degrees
Financing - 1.6xle Turbines
Amounts in CAD 000s unless otherwise stated
As at January 21, 2010

	Notes	For the year ended December 31, 2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032
EX-IM Loan Amortization	[F1]	[redacted]																		
Beginning balance																				
Less: Principal repayment																				
Ending balance																				
Interest																				
Total Principal and interest																				
Ending balance/kW																				
Term Loan Amortization	[F2]																			
Beginning balance																				
Less: Principal repayment																				
Ending balance																				
Interest																				
Total Principal and interest																				
Ending balance/kW																				

Notes:
[F1] [redacted]
[F2] [redacted]

Financing for the 10% increase in capacity

EX-IM Loan Amortization	[redacted]
Beginning balance	
Less: Principal repayment	
Ending balance	
Interest	
Term Loan Amortization	
Beginning balance	
Less: Principal repayment	
Ending balance	
Interest	

Schedule 2I
Project Twenty-Two Degrees
Financing - 2.5XL Turbines
Amounts in CAD 000s unless otherwise stated
As at January 21, 2010

		For the year ended December 31,																		
	Notes	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**
EX-IM Loan Amortization	**[F1]**	[redacted]																		
Beginning balance																				
Less: Principal repayment																				
Ending balance																				
Interest																				
Total Principal and interest																				
Ending balance/kW																				
Term Loan Amortization	**[F2]**																			
Beginning balance																				
Less: Principal repayment																				
Ending balance																				
Interest																				
Total Principal and interest																				
Ending balance/kW																				

Notes:
[F1] [redacted]
[F2]

Financing for the 10% increase in capacity

EX-IM Loan Amortization	[redacted]
Beginning balance	
Less: Principal repayment	
Ending balance	
Interest	
Term Loan Amortization	
Beginning balance	
Less: Principal repayment	
Ending balance	
Interest	

Schedule 2J
Project Twenty-Two Degrees
Development and Construction Costs - 1.6xle Turbines
Amounts in CAD 000's unless otherwise stated
As at January 21, 2010

	Notes		Dec 31, 2008	Dec 31, 2009	pre-Jan 21 2010	post Jan 21 2010	For the year ended Dec 31, 2011	2012	2013	Mar 31, 2014
			Development period						Construction period	
Capital costs	[F1]		[redacted]							
Development costs										
WTG costs	[F2]									
BoP costs	[F3]									
Total unlevered capital costs										
Financing costs										
Total capital costs										
Period			1.56	0.56	0 03					
Inflation rate	[F4]		1.15%	2.98%	0.34%					
PV factor for the period			[redacted]							
Cumulative PV factor										
Inflated cash flows										
Inflated cash flows (excluding financing amounts)										
Historical capital expenditures										
Capital expenditures financed by equity										
Capital expenditures financed by debt										
LOW										
Period						0 47	1 44	2 44	3 44	4 07
PV Factor	[F5]	12.5%				[redacted]				
Discounted cash flows										
Sum of development and construction costs		[redacted]								
Discounted cash flows (excluding financing amounts)										
Future capital expenditures										
Capital expenditures financed by equity										
Capital expenditures financed by debt	[F6]									
HIGH										
Period						[redacted]				
PV Factor	[F5]	11.5%								
Discounted cash flows										
Sum of development and construction costs		[redacted]								
Discounted cash flows (excluding financing amounts)										
Future capital expenditures										
Capital expenditures financed by equity										
Capital expenditures financed by debt	[F6]									

Notes:

[F1] We have tested the reasonability of total capital costs with comparable project benchmark data. See Schedule 7 for further details. Based on our research, total capital costs were determined to be reasonable.

[F2] [redacted]

[F3] BoP costs include contracted construction costs which are based on Management's best es imates based on other projects and pricing provided by Mortenson, he selected contractor for he project. Investor's Schedule of Exhibits **C0376** (001856-3.2.3).

[F4] Inflation rate is based on Bank of Canada's core CPI rate.

[F5] Schedule 6.

[F6] [redacted]

Schedule 2K
Project Twenty-Two Degrees
Development and Construction Costs (Capacity Expansion)
Amounts in CAD 000's unless otherwise stated
As at January 21, 2010

	Notes		Dec 31, 2008	Dec 31, 2009	pre-Jan 21 2010	post Jan 21 2010	For the year ended Dec 31, 2011	2012	2013	Mar 31, 2014
			Development period						Construction period	
Capital costs	**[F1]**		[redacted]							
Development costs										
WTG costs	**[F2]**									
BoP costs	**[F3]**									
Total unlevered capital costs										
Financing costs										
Total capital costs										
Period			1.56	0.56	0.03					
Inflation rate	**[F4]**		1.15%	2.98%	0.34%					
PV factor for the period			[redacted]							
Cumulative PV factor										
Inflated cash flows										
Inflated cash flows (excluding financing amounts)										
LOW										
Period						0.47	1.44	2.44	3.44	4.07
PV Factor	**[F5]**	12.5%				[redacted]				
Discounted cash flows		[redacted]								
Sum of development and construction costs										
Discounted cash flows (excluding financing amounts)										
Future capital expenditures										
Capital expenditures financed by equity										
Capital expenditures financed by debt	**[F6]**									
HIGH										
Period						0.47	1.44	2.44	3.44	4.07
PV Factor	**[F5]**	11.5%				[redacted]				
Discounted cash flows		[redacted]								
Sum of development and construction costs										
Discounted cash flows (excluding financing amounts)										
Future capital expenditures										
Capital expenditures financed by equity										
Capital expenditures financed by debt	**[F6]**									

Notes:

[F1] We have tested the reasonability of total capital costs with comparable project benchmark data. See Schedule 7 for further details. Based on our research, total capital costs were determined to be reasonable.

[F2] WTG costs include direct costs related to the wind turbines which are based on Management's best estimates from other projects and pricing provided by GE. The most substantial cost included in this category is the cost of the wind turbines of $2,165,000 for each 1.6xle wind turbine. Investor's Schedule of Exhibits **C0380** (002024 page 7).

[F3] BoP costs include contracted construction costs which are based on Management's best estimates based on other projects and pricing provided by Mortenson, the selected contractor for the project. Investor's Schedule of Exhibits **C0376** (001856-3.2.3).

[F4] Inflation rate is based on Bank of Canada's core CPI rate.

[F5] Schedule 6.

[F6] Based on discussions with Management, we have assumed 100% equity financing for the development period and 80%/20% debt/equity financing split for the construction period, which is also consistent with our market research.

Schedule 2L
Project Twenty-Two Degrees
Development and Construction Costs - 2.5XL Turbines
Amounts in CAD 000's unless otherwise stated
As at November 25, 2009

	Notes		Dec 31, 2008	pre-Nov 25 2009	post Nov 25 2009	For the year ended Dec 31, 2010	2011	2012	2013	Mar 31, 2014
			Development period						Construction period	
Capital costs	**[F1]**		[redacted]							
Development costs										
WTG costs	**[F2]**									
BoP costs	**[F3]**									
Total unlevered capital costs (2.5XL turbine)										
Total unlevered capital costs (1.6xle turbine)	**[F4]**									
Total incremental unlevered capital costs										
Financing costs										
Total financing amounts (2.5XL turbine)										
Total financing amounts (1.6xle turbine)	**[F4]**									
Total incremental financing amounts										
Total capital costs (2.5XL turbine)										
Total capital costs (1.6xle turbine)										
Total incremental capital costs										
Period			1.40	0.45						
Inflation rate	**[F5]**		1.15%	2.98%						
PV factor for the period			[redacted]							
Cumulative PV factor										
Inflated cash flows										
LOW										
Period					0.05	0.60	1.60	2.60	3.60	4.22
PV Factor	**[F6]**	12.5%			[redacted]					
Discounted cash flows										
Sum of development and construction costs		[redacted]								
Discounted cash flows (excluding financing amounts)										
Future capital expenditures										
Capital expenditures financed by equity										
Capital expenditures financed by debt	**[F7]**									
HIGH										
Period					0.05	0.60	1.60	2.60	3.60	4.22
PV Factor	**[F6]**	11.5%			[redacted]					
Discounted cash flows										
Sum of development and construction costs		[redacted]								
Discounted cash flows (excluding financing amounts)										
Future capital expenditures										
Capital expenditures financed by equity										
Capital expenditures financed by debt	**[F7]**									

Notes:

[F1] We have tested the reasonability of total capital costs with comparable project benchmark data. See Schedule 7 for further details. Based on our research, total capital costs were determined to be reasonable.

[F2] [redacted]

[F3] BoP costs include contracted construction costs which are based on Management's best estimates based on other projects and pricing provided by Mortenson, the selected contractor for the projec Investor's Schedule of Exhibits **C0358** (000967-.9.15.1.1)

[F4] Schedule 2J.

[F5] Inflation rate is based on Bank of Canada's core CPI rate.

[F6] Schedule 6.

[F7] [redacted]

Schedule 2M
Project Twenty-Two Degrees
Development and Construction Costs - 2.5XL Turbines
Amounts in CAD 000's unless otherwise stated
As at November 25, 2009

	Notes		Dec 31, 2008	pre-Nov 25 2009	post Nov 25 2009	For the year ended Dec 31, 2010	2011	2012	2013	Mar 31, 2014
			Development period						Construction period	
Capital costs	**[F1]**		[redacted]							
Development costs										
WTG costs	**[F2]**									
BoP costs	**[F3]**									
Total unlevered capital costs (2.5XL turbines - capacity expansion)										
Total unlevered capital costs (2.5XL turbines)	**[F4]**									
Total incremental unlevered capital costs										
Financing costs										
Total unlevered capital costs (2.5XL turbines - capacity expansion)										
Total financing amounts (2.5XL turbines)										
Total incremental financing amounts										
Total capital costs (2.5XL turbines - capacity expansion)										
Total capital costs (2.5XL turbines)										
Total incremental capital costs										
Period			1.40	0.45						
Inflation rate	**[F5]**		1.15%	2.98%						
PV factor for the period			[redacted]							
Cumulative PV factor										
Inflated cash flows										
LOW										
Period					0.05	0.60	1.60	2.60	3.60	4.22
PV Factor	**[F6]**	12.5%			[redacted]					
Discounted cash flows										
Sum of development and construction costs		[redacted]								
Discounted cash flows (excluding financing amounts)										
Future capital expenditures										
Capital expenditures financed by equity										
Capital expenditures financed by debt	**[F7]**									
HIGH										
Period					0.05	0.60	1.60	2.60	3.60	4.22
PV Factor	**[F6]**	11.5%			[redacted]					
Discounted cash flows										
Sum of development and construction costs		[redacted]								
Discounted cash flows (excluding financing amounts)										
Future capital expenditures										
Capital expenditures financed by equity										
Capital expenditures financed by debt	**[F7]**									

Notes:

[F1] We have tested the reasonability of total capital costs with comparable project benchmark data. See Schedule 7 for further details. Based on our research, total capital costs were determined to be reasonable.

[F2] [redacted]

[F3] BoP costs include contracted construction costs which are based on Management's best estimates based on other projects and pricing provided by Mortenson, the selected contractor for the projec Investor's Schedule of Exhibits **C0358** (000967-.9.15.1.1)

[F4] Schedule 2L.

[F5] Inflation rate is based on Bank of Canada's core CPI rate.

[F6] Schedule 6.

[F7] [redacted]

Schedule 3A
Project Arran
Summary
Amounts in 000's CAD unless otherwise stated

			Discounted cash flows		
			Low	Midpoint	High
NAFTA 1102, NAFTA 1103 & NAFTA 1105	**[F1]**				
Base Case		**Schedule 3B**	57,100	61,126	65,152
Economic Development Adder		**Schedule 3C**	4,097	4,273	4,450
Capacity expansion		**Schedule 3D**	6,594	7,025	7,456
Economic Development Adder applicable to capacity expansion		**Schedule 3D**	410	427	445
NAFTA 1106			22,997	24,054	25,111
Total			91,198	96,906	102,614
NAFTA 1106					
Base Case		**Schedule 3E**	21,732	22,725	23,718
Economic Development Adder		**Schedule 3F**	267	280	293
Capacity expansion		**Schedule 3G**	972	1,022	1,073
Economic Development Adder applicable to capacity expansion		**Schedule 3G**	27	28	28
Total			22,997	24,054	25,111
Total claim (pre-tax)			**91,198**	**96,906**	**102,614**
Total claim, rounded			**91,000**	**97,000**	**103,000**

Notes

[F1] Please refer to Sections 1.12 to 1.27 for further details related to the claims.

Schedule 3B
Project Arran
Discounted Cash Flows - NAFTA Article 1102, 1103, 1105 (Base Case)
Amounts in CAD 000s unless otherwise stated
As at January 21, 2010

	Notes		pre-Jan 21 2008	2009	2010	post Jan 21 2010	2011	2012	2013	2014	2015	2021	2022	2032	2033	2034
Revenue																
Price	[F1]	0.42%								142.40	142.99	146.59	147.20	153.42	154.06	154.70
Production (000s MWh)	[F2]		[redacted]													
Total revenue																
Operating expenses	[F3]															
Land Payments [redacted]		2.20%														
Asset manager	[F4]															
Unplanned maintenance	[F4]															
Planned maintenance	[F4]															
Transmission charge	[F4]															
BOP maintenance	[F4]															
Property taxes	[F4]															
Insurance	[F4]															
Total operating expenses																
EBITDA																
Less: Interest expense																
EX-IM loan interest	[F5]															
Term loan interest	[F5]															
Net cash flows after interest																
Less: Taxes @ 25.00%	[F6]															
After-tax cash flow																
Less: Capital expenditures																
Less: Debt principal repayments																
EX-IM loan principal payment	[F5]															
Term loan principal payment	[F5]															
Levered free cash flows																
LOW																
Percent of year remaining						94%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%
Discounting period			[redacted]													
Discount rate		[F7]														
Cumula ive PV factor																
Discounted operating cash flows																
Equity-financed capital expenditures		[F8]														
Net present value of cash flows		[redacted]														
Gross pre-tax net present value of cash flows																
HIGH																
Discount rate			[redacted]													
Cumula ive PV factor																
Discounted operating cash flows																
Equity-financed capital expenditures		[F8]														
Net present value of cash flows		[redacted]														
Gross pre-tax net present value of cash flows																

Notes:

[F1] Power price based on FIT application.
[F2] Annual energy production based on the project's wind study. Investor's Schedule of Exhibits**C0374** (001852-3.1 2).
[F3] We have tested the reasonability of total operating expenses with comparable project benchmark data. See Schedule 7 for further details. Based on our research, total operating expenses were determined to be reasonable.
[F4] We have assumed that these expenses would increase annually by 2.2%, based on inflation forecasts from Economic Intelligence Unit.
[F5] Schedule 3H.
[F6] Tax rates are based on the substantively enacted tax rates as at the Valuation Date.
Tax expense:

			2008	2009	2010 pre-Jan 21	2010 post Jan 21	2011	2012	2013	2014	2015	2021	2022	2032	2033	2034
Net cash flows after interest	**[A]**		[redacted]													
Less: tax deductions/adjustments	**[B]**															
Taxable income	**[A] + [B]**															
Tax expense		25.00%														

[B] The tax deductions/adjustments are quantified by considering the tax attributes available for renewable energy projects. Specifically, we have considered capital cost allowances and Canadian Renewable Conservation Expenses.
[F7] Schedule 6.
[F8] Schedule 3J.
[F9] For presentation purposes, we have ommited the visibility of certain years of the forecast.

Schedule 3C
Project Arran
Discounted Cash Flows - NAFTA Article 1102, 1103 & 1105 (Economic Development Adder)
Amounts in CAD 000s unless otherwise stated
As at January 21, 2010

				pre-Jan 21		post Jan 21	For the year ended December 31,								
	Notes		2008	2009	2010	2010	2011	2012	2013	2014	2015	2021	2022	2032	2033	2034
Revenue																
Price	[F1]	0.42%	[redacted]													
Production (000s MWh)	[F2]															
Total revenue																
Operating expenses	[F3]															
Land Payments [redacted]		2.20%														
Asset manager	[F4]															
Unplanned maintenance	[F4]															
Planned maintenance	[F4]															
Transmission charge	[F4]															
BOP maintenance	[F4]															
Property taxes	[F4]															
Insurance	[F4]															
Total operating expenses																
EBITDA																
Less: Interest expense																
EX-IM loan interest	[F5]															
Term loan interest	[F5]															
Net cash flows after interest																
Less: Taxes @ 25.00%	[F6]															
After-tax cash flow																
Less: Debt principal repayments																
EX-IM loan principal payment	[F5]															
Term loan principal payment	[F5]															
Levered free cash flows																
LOW																
Percent of year remaining						94%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%
Discounting period			[redacted]													
Discount rate		[F7]														
Cumulative PV factor																
Discounted operating cash flows																
Equity-financed capital expenditures		[F8]														
Net present value of cash flows		[redacted]														
Less: NPV of base case	[F9]															
NPV of incremental cash flows																
Gross pre-tax NPV of incremental cash flows																
HIGH																
Discount rate																
Cumulative PV factor																
Discounted operating cash flows																
Equity-financed capital expenditures																
Net present value of cash flows																
Less: NPV of base case	[F9]															
NPV of incremental cash flows																
Gross pre-tax NPV of incremental cash flows																

Notes:

[F1] Power price based on FIT applica ion. In this scenario we have added he Economic Development Adder of 0 27 cents per kWh hat was offered to Samsung in the Amended GEIA. Investor's Schedule of Exhibits **C0282** (4403).

[F2] Annual energy production based on the project's wind study. Investor's Schedule of Exhibits **C0374** (001852-3.1.2).

[F3] We have tested the reasonability of total operating expenses with comparable project benchmark data. See Schedule 7 for further details. Based on our research, total operating expenses were determined to be reasonable.

[F4] We have assumed hat these expenses would increase annually by 2.2%, based on inflation forecasts from Economic Intelligence Unit.

[F5] Schedule 3H.

[F6] Tax rates are based on the substantively enacted tax rates as at the Valuation Date.

Tax expense:

					pre-Jan 2	post Jan 21										
			2008	**2009**	**2010**	**2010**	**2011**	**2012**	**2013**	**2014**	**2015**	**2021**	**2022**	**2032**	**2033**	**2034**
Net cash flows after interest	**[A]**		[redacted]													
Less: tax deductions	**[B]**															
Taxable income	**[A] + [B]**															
Tax expense		25.00%														

[B] The tax deductions/adjustments are quantified by considering the tax attributes available for renewable energy projects. Specifically, we have considered capital cost allowances and Canadian Renewable Conservation Expenses.

[F7] Schedule 6.

[F8] Schedule 3J.

[F9] Schedule 3B

[F10] For presenta ion purposes, we have ommited the visibility of certain years of the forecast.

Schedule 3D
Project Arran
Discounted Cash Flows - NAFTA Article 1102, 1103 & 1105 (Capacity Expansion)
Amounts in CAD 000s unless otherwise stated
As at January 21, 2010

				pre-Jan 21		post Jan 21				For the year ended December 31,						
	Notes		**2008**	**2009**	**2010**	**2010**	**2011**	**2012**	**2013**	**2014**	**2015**	**2021**	**2022**	**2032**	**2033**	**2034**
Revenue																
Price	[F1]	0.42%								142.40	142.99	146.59	147.20	153.42	154.06	154.70
Production (000s MWh)	[F2]		[redacted]													
Total revenue			[redacted]													
Operating expenses	[F3]		[redacted]													
Land Payments [redacted]		2 20%	[redacted]													
Asset manager	[F4]		[redacted]													
Unplanned maintenance	[F4]		[redacted]													
Planned maintenance	[F4]		[redacted]													
Transmission charge	[F4]		[redacted]													
BOP maintenance	[F4]		[redacted]													
Property taxes	[F4]		[redacted]													
Insurance	[F4]		[redacted]													
Total operating expenses			[redacted]													
EBITDA			[redacted]													
Less Interest expense			[redacted]													
EX-IM loan interest	[F5]		[redacted]													
Term loan interest	[F5]		[redacted]													
Net cash flows after interest			[redacted]													
Less: Taxes @ 25.00%	[F6]		[redacted]													
After-tax cash flow			[redacted]													
Less Capital expenditures			[redacted]													
Less Debt principal repayments			[redacted]													
EX-IM loan principal payment	[F5]		[redacted]													
Term loan principal payment	[F5]		[redacted]													
Levered free cash flows			[redacted]													
LOW			[redacted]													
Percent of year remaining			[redacted]													
Discounting period			[redacted]													
Discount rate	[F7]		[redacted]													
Cumulative PV factor			[redacted]													
Discounted operating cash flows			[redacted]													
Equity-financed capital expenditures	[F8]		[redacted]													
Net present value of cash flows		[redacted]	[redacted]													
Less: NPV NAFTA 1102/1103/1105 - Base Case	[F9]	[redacted]														
NPV of incremental cash flows		[redacted]														
Gross pre-tax net present value of cash flows		[redacted]														
<u>Including Economic Development Adder</u>		[redacted]														
NPV of EDA on capacity expansion	[F10]	[redacted]														
Less: NPV NAFTA 1102/1103/1105 - EDA	[F11]	[redacted]														
NPV of incremental cash flows		[redacted]														
Gross pre-tax NPV of incremental cash flows		[redacted]														

Schedule 3D
Project Arran
Discounted Cash Flows - NAFTA Article 1102, 1103 & 1105 (Capacity Expansion)
Amounts in CAD 000s unless otherwise stated
As at January 21, 2010

	Notes		pre-Jan 21			post Jan 21	For the year ended December 31,									
			2008	2009	2010	2010	2011	2012	2013	2014	2015	2021	2022	2032	2033	2034
HIGH																
Discount rate	[F7]		[redacted]													
Cumulative PV factor			[redacted]													
Discounted operating cash flows			[redacted]													
Equity-financed capital expenditures	[F8]	[redacted]	[redacted]													
Net present value of cash flows		[redacted]	[redacted]													
Less: NPV NAFTA 1102/1103/1105 - Base Case	[F9]	[redacted]	[redacted]													
NPV of incremental cash flows		[redacted]														
Gross pre-tax net present value of cash flows		[redacted]														
Including Economic Development Adder		[redacted]														
NPV of EDA on capacity expansion	[F10]	[redacted]														
Less: NPV NAFTA 1102/1103/1105 - EDA	[F11]	[redacted]														
NPV of incremental cash flows		[redacted]														
Gross pre-tax NPV of incremental cash flows		[redacted]														

Notes

[F1] Power price based on FIT application. In this scenario we have added the Economic Development Adder of 0 27 cents per kWh that was offered to Samsung in the Amended GEIA. Investor's Schedule of Exhibits **C0282** (4403).
[F2] Annual energy production based on the project's wind study. Investor's Schedule of Exhibits **C0374** (001852-3.1.2).
[F3] We have tested the reasonability of total operating expenses with comparable project benchmark data. See Schedule 7 for further details. Based on our research, total operating expenses were determined to be reasonable.

[F4] We have assumed that these expenses would increase annually by 2.2%, based on inflation forecasts from Economic Intelligence Unit.
[F5] Schedule 3H.
[F6] Tax rates are based on the substantively enacted tax rates as at the Valuation Date.
Tax expense:

			pre-Jan 2			post Jan 21										
			2008	2009	2010	2010	2011	2012	2013	2014	2015	2021	2022	2032	2033	2034
Net cash flows after interest	[A]		[redacted]													
Less: tax deductions/adjustments	[B]		[redacted]													
Taxable income	[A] + [B]		[redacted]													
Tax expense		25 00%	[redacted]													

[B] The tax deductions/adjustments are quantified by considering the tax attributes available for renewable energy projects. Specifically, we have considered capital cost allowances and Canadian Renewable Conservation Expenses.
[F7] Schedule 6.
[F8] Schedule 3K.
[F9] Schedule 3B.
[F10] We have calculated the additional Economic Losses related to the Economic Development Adder on the 10% capacity expansion by increasing the price (as used in Schedule 3C). The operating, capital and financing costs remain the same.
[F11] Schedule 3C.
[F12] For presentation purposes, we have ommited the visibility of certain years of the forecast.

Schedule 3E
Project Arran
Discounted Cash Flows - NAFTA Article 1106 (Base Case)
Amounts in CAD 000s unless otherwise stated
As at November 25, 2009

			pre-Nov 25		post Nov 25		For the year ended December 31,									
	Notes		2008	2009	2009	2010	2011	2012	2013	2014	2015	2020	2021	2032	2033	2034
Revenue																
Price	[F1]	0.42%								142.40	142.99	145.99	146.59	153.42	154.06	154.70
Production (000s MWh)	[F2]		[redacted]													
Total revenue																
Operating expenses	[F3]															
Land Payments [redacted]		2.20%														
Asset manager	[F4]															
Unplanned maintenance	[F4]															
Planned maintenance	[F4]															
Transmission charge	[F4]															
BOP maintenance	[F4]															
Property taxes	[F4]															
Insurance	[F4]															
Total operating expenses																
EBITDA																
Less: Interest expense																
EX-IM loan interest	[F5]															
Term loan interest	[F5]															
Net cash flows after interest																
Less: Taxes @ 25.00%	[F6]															
After-tax cash flow																
Less: Capital expenditures																
Less: Debt principal repayments																
EX-IM loan principal payment	[F5]															
Term loan principal payment	[F5]															
Levered free cash flows																
NAFTA Article 1106 - Base Case																
NAFTA Article 1102/1103/1105 - Base Case	[F7]															
Incremental levered free cash flows																
LOW																
Percent of year remaining																
Discounting period																
Discount rate		[F8]														
Cumula ive PV factor																
Discounted incremental operating cash flows																
Incremental equity-financed capital expenditures		[F9]														
Net present value of cash flows																
Gross pre-tax net present value of cash flows																
HIGH																
Discount rate																
Cumula ive PV factor																
Discounted incremental operating cash flows																
Incremental equity-financed capital expenditures																
Net present value of cash flows																
Gross pre-tax net present value of cash flows																

Notes:

[F1] Power price based on FIT application.
[F2] Annual energy production based on the project's wind study. Investor's Schedule of Exhibits **C0374** (001852-3.1.2).
[F3] We have tested he reasonability of total opera ing expenses with comparable project benchmark data. See Schedule 7 for further details. Based on our research, total operating expenses were determined to be reasonable.
[F4] We have assumed hat these expenses would increase annually by 2.2%, based on inflation forecasts from Economic Intelligence Unit.
[F5] Schedule 3I.
[F6] Tax rates are based on the substantively enacted tax rates as at the Valuation Date.

Tax expense:

				pre-Nov 2	post Nov 25,											
			2008	**2009**	**2009**	**2010**	**2011**	**2012**	**2013**	**2014**	**2015**	**2020**	**2021**	**2032**	**2033**	**2034**
Net cash flows after interest	**[A]**		[redacted]													
Less: tax deductions/adjustments	**[B]**															
Taxable income	**[A] + [B]**															
Tax expense		25.00%														

[B] The tax deductions/adjustments are quan ified by considering the tax attributes available for renewable energy projects. Specifically, we have considered capital cost allowances and Canadian Renewable Conserva ion Expenses.

[F7] Schedule 3B
[F8] Schedule 6.
[F9] Schedule 3L.
[F10] For presentation purposes, we have ommited the visibility of certain years of the forecast.

Schedule 3F
Project Arran
Discounted Cash Flows - NAFTA Article 1106 (Economic Development Adder)
Amounts in CAD 000s unless otherwise stated
As at November 25, 2009

	Notes		pre-Nov 25 2008	pre-Nov 25 2009	post Nov 25 2009	2010	2011	2012	2013	2014	2015	2020	2021	2032	2033	2034
									For the year ended December 31,							
Revenue																
Price	[F1]	0.42%								145.10	145.69	148.69	149.29	156.12	156.76	157.40
Production (000s MWh)	[F2]		[redacted]													
Total revenue																
Operating expenses	[F3]															
Land Payment [redacted]		2.20%														
Asset manager	[F4]															
Unplanned maintenance	[F4]															
Planned maintenance	[F4]															
Transmission charge	[F4]															
BOP maintenance	[F4]															
Property taxes	[F4]															
Insurance	[F4]															
Total operating expenses																
EBITDA																
Less: Interest expense																
EX-IM loan interest	[F5]															
Term loan interest	[F5]															
Net cash flows after interest																
Less: Taxes @ 25.00%	[F6]															
After-tax cash flow																
Less: Debt principal repayments																
EX-IM loan principal payment	[F5]															
Term loan principal payment	[F5]															
Levered free cash flows																
NAFTA Article 1106 - EDA																
NAFTA Article 1106 - Base Case	[F7]															
Incremental levered free cash flows																
LOW																
Percent of year remaining																
Discounting period																
Discount rate																
Cumulative PV factor																
Discounted incremental operating cash flows																
Net present value of incremental cash flows																
Less: NPV NAFTA 1102/1103/1105 - EDA	[F8]															
NPV of incremental cash flows																
Gross pre-tax NPV of incremental cash flows																
HIGH																
Discount rate																
Cumulative PV factor																
Discounted incremental operating cash flows																
Net present value of cash flows																
Less: NPV NAFTA 1102/1103/1105 - EDA	[F8]															
NPV of incremental cash flows																
Gross pre-tax NPV of incremental cash flows																

Notes:

[F1] Power price based on FIT application. In this scenario we have added he Economic Development Adder of 0 27 cents per kWh hat was offered to Samsung in the Amended GEIA. Investor's Schedule of Exhibits **C0282** (4403).

[F2] Annual energy produc ion based on the project's wind study. Investor's Schedule of Exhibits **C0374** (001852-3.1.2).

[F3] We have tested the reasonability of total operating expenses with comparable project benchmark data. See Schedule 7 for further details. Based on our research, total operating expenses were determined to be reasonable.

[F4] We have assumed hat these expenses would increase annually by 2.2%, based on inflation forecasts from Economic Intelligence Unit.

[F5] Schedule 3I.

[F6] Tax rates are based on the substantively enacted tax rates as at the Valuation Date.

Tax expense:

			2008	pre-Nov 2 2009	post Nov 25, 2009	2010	2011	2012	2013	2014	2015	2020	2021	2032	2033	2034
Net cash flows after interest	**[A]**		[redacted]													
Less: tax deductions/adjustments	**[B]**															
Taxable income	**[A] + [B]**															
Tax expense		25.00%														

[B] The tax deductions/adjustments are quantified by considering the tax attributes available for renewable energy projects. Specifically, we have considered capital cost allowances and Canadian Renewable Conservation Expenses.

[F7] Schedule 3E.

[F8] Schedule 3C has been discounted to reflect he Valuation Date for the NAFTA 1106 claim:

		Low	High	
NPV of base case (NAFTA Article 1102/1103/1105 - EDA)	**Schedule 3C**	[redacted]		as at Jan. 21, 2010
Discount factor adjustment		0 982	0.983	
NPV of base case (NAFTA Article 1102/1103/1105 - EDA)		[redacted]		as at Nov. 25, 2009

[F9] For presenta ion purposes, we have ommited the visibility of certain years of the forecast.

Schedule 3G
Project Arran
Discounted Cash Flows - NAFTA Article 1106 (Base Case)
Amounts in CAD 000s unless otherwise stated
As at November 25, 2009

	Notes		For the year ended December 31, 2011	2012	2013	2014	2015	2020	2021	2032	2033	2034
Revenue												
Price	[F1]	0.42%				142.40	142.99	145.99	146.59	153.42	154.06	154.70
Production (000s MWh)	[F2]		[redacted]									
Total revenue												
Operating expenses	[F3]											
Land Payments [redacted]		2.20%										
Asset manager	[F4]											
Unplanned maintenance	[F4]											
Planned maintenance	[F4]											
Transmission charge	[F4]											
BOP maintenance	[F4]											
Property taxes	[F4]											
Insurance	[F4]											
Total operating expenses												
EBITDA												
Less Interest expense												
EX-IM loan interest	[F5]											
Term loan interest	[F5]											
Net cash flows after interest												
Less: Taxes @ 25.00%	[F6]											
After-tax cash flow												
Less Capital expenditures												
Less Debt principal repayments												
EX-IM loan principal payment	[F5]											
Term loan principal payment	[F5]											
Levered free cash flows												
NAFTA Article 1106 - Capacity Expansion												
NAFTA Article 1106 - Base Case	[F7]											
Incremental levered free cash flows												
LOW												
Percent of year remaining												
Discounting period												
Discount rate	[F8]											
Cumulative PV factor												
Discounted incremental operating cash flows												
Incremental equity-financed capital expenditures	[F9]	[redacted]										
Net present value of cash flows												
Less: NPV NAFTA 1102/1103/1105 - Capacity Expansion	[F10]											
NPV of incremental cash flows												
Gross pre-tax NPV of incremental cash flows												
Including Economic Development Adder												
NPV of Economic Development Adder on capacity expansion	[F6]											
Less: NPV NAFTA 1102/1103/1105 - Capacity Expansion with EDA	[F10]											
NPV of incremental cash flows												
Gross pre-tax NPV of incremental cash flows												

Schedule 3G
Project Arran
Discounted Cash Flows - NAFTA Article 1106 (Base Case)
Amounts in CAD 000s unless otherwise stated
As at November 25, 2009

	Notes	For the year ended December 31, 2011	2012	2013	2014	2015	2020	2021	2032	2033	2034
HIGH											
Discount rate	[F8]	[redacted]									
Cumulative PV factor											
Discounted incremental operating cash flows											
Incremental equity-financed capital expenditures	[F9]										
Net present value of cash flows											
Less: NPV NAFTA 1102/1103/1105 - Capacity Expansion	[F10]										
NPV of incremental cash flows											
Gross pre-tax NPV of incremental cash flows											
Including Economic Development Adder											
NPV of Economic Development Adder on capacity expansion	[F6]										
Less: NPV NAFTA 1102/1103/1105 - Capacity Expansion with EDA	[F10]										
NPV of incremental cash flows											
Gross pre-tax NPV of incremental cash flows											

Notes

[F1] Power price based on FIT application. In this scenario we have added the Economic Development Adder of 0 27 cents per kWh that was offered to Samsung in the Amended GEIA. Investor's Schedule of Exhibits **C0282** (4403).
[F2] Annual energy production based on the project's wind study. Investor's Schedule of Exhibits **C0374** (001852-3.1 2).
[F3] We have tested the reasonability of total operating expenses with comparable project benchmark data. See Schedule 7 for further details. Based on our research, total operating expenses were determined to
[F4] We have assumed that these expenses would increase annually by 2.2%, based on inflation forecasts from Economic Intelligence Unit.
[F5] Schedule 3I.
[F6] Tax rates are based on the substantively enacted tax rates as at the Valuation Date.
Tax expense:

			2011	2012	2013	2014	2015	2020	2021	2032	2033	2034
Net cash flows after interest	[A]		[redacted]									
Less: tax deductions/adjustments	[B]											
Taxable income	[A] + [B]											
Tax expense		25.00%										

[B] The tax deductions/adjustments are quantified by considering the tax attributes available for renewable energy projects. Specifically, we have considered capital cost allowances and Canadian Renewable
[F6] We have calculated the additional Economic Losses related to the Economic Development Adder on the 10% capacity expansion by increasing the price (as used in Schedule 3F). The operating, capital and fin
[F7] Schedule 3E
[F8] Schedule 6.
[F9] Schedule 3M.
[F10] Schedule 3D has been discounted to reflect the Valuation Date for the NAFTA 1106 claim:

		Low	High	
NPV of base case (NAFTA Article 1102/1103/1105 - Capacity Expansion)	**Schedule 3D**	[redacted]		as at Jan. 21, 2010
Discount factor adjustment to reflect Nov. 25, 2009 Date of Breach		0 982	0.985	
NPV of base case (NAFTA Article 1102/1103/1105 - Capacity Expansion)		[redacted]		as at Nov. 25, 2009
NPV of base case (NAFTA Article 1102/1103/1105 - Capacity Expansion including EDA)	**Schedule 3D**	[redacted]		as at Jan. 21, 2010
Discount factor adjustment to reflect Nov. 25, 2009 Date of Breach		0 982	0.985	
NPV of base case (NAFTA Article 1102/1103/1105 - Capacity Expansion including EDA)		[redacted]		as at Nov. 25, 2010

[F11] For presentation purposes, we have ommited the visibility of certain years of the forecast.

Schedule 3H
Project Arran
Financing - 1.6xle Turbines
Amounts in CAD unless otherwise stated
As at January 21, 2010

	Notes	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032
		For the year ended December 31,																		
EX-IM Loan Amortization																				
Beginning balance	[F1]	[redacted]																		
Less: Principal repayment																				
Ending balance																				
Interest																				
Total Principal and interest																				
Ending balance/kW																				
Term Loan Amortization																				
Beginning balance	[F2]																			
Less: Principal repayment																				
Ending balance																				
Interest																				
Total Principal and interest																				
Ending balance/kW																				

Notes
[F1] [redacted]
[F2]

Financing for 10% Capacity expansion

EX-IM Loan Amortization	
Beginning balance	[redacted]
Less: Principal repayment	
Ending balance	
Interest	
Term Loan Amortization	
Beginning balance	
Less: Principal repayment	
Ending balance	
Interest	

Schedule 3I
Project Arran
Financing - 2.5XL Turbines
Amounts in CAD unless otherwise stated
As at January 21, 2010

	Notes	For the year ended December 31, 2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032
EX-IM Loan Amortization		[redacted]																		
Beginning balance	[F1]																			
Less: Principal repayment																				
Ending balance																				
Interest																				
Total Principal and interest																				
Ending balance/kW																				
Term Loan Amortization																				
Beginning balance																				
Less: Principal repayment	[F2]																			
Ending balance																				
Interest																				
Total Principal and interest																				
Ending balance/kW																				

Notes
[F1] [redacted]

[F2]

Financing for 10% Capacity expansion

EX-IM Loan Amortization																				
Beginning balance		[redacted]																		
Less: Principal repayment																				
Ending balance																				
Interest																				
Term Loan Amortization																				
Beginning balance																				
Less: Principal repayment																				
Ending balance																				
Interest																				

Schedule 3J
Project Arran
Development and Construction Costs - 1.6xle Turbines
Amounts in CAD 000s unless otherwise stated
As at January 21, 2010

	Notes		Dec 31, 2008	Dec 31, 2009	pre-Jan 21 2010	post Jan 21 2010	For the year ended Dec 31, 2011	For the year ended Dec 31, 2012	For the year ended Dec 31, 2013	Mar 31, 2014
			Development period						Construction period	
Capital costs	[F1]		[redacted]							
Development costs										
WTG costs	[F2]									
BoP costs	[F3]									
Total unlevered capital costs										
Financing costs										
Total capital costs										
Period			2.44	1.44	0.47					
Infla ion rate	[F4]		1.15%	2.98%	0.34%					
PV factor for he period			[redacted]							
Cumulative PV factor										
Inflated cash flows										
Inflated cash flows (excluding financing amounts)										
Historical capital expenditures										
Capital expenditures financed by equity	[F5]									
Capital expenditures financed by debt	[F5]									
LOW										
Period						0.47	1.44	2.44	3.44	4.07
PV Factor	[F6]	12.5%				[redacted]				
Discounted cash flows										
Sum of pre-operating cash flows		[redacted]								
Discounted cash flows (excluding financing amounts)										
Future capital expenditures										
Capital expenditures financed by equity										
Capital expenditures financed by debt	[F5]									
HIGH										
Period						0.47	1.44	2.44	3.44	4.07
PV Factor	[F6]	11.5%				[redacted]				
Discounted cash flows										
Sum of pre-operating cash flows		[redacted]								
Discounted cash flows (excluding financing amounts)										
Future capital expenditures										
Capital expenditures financed by equity										
Capital expenditures financed by debt	[F5]									

Notes:

[F1] We have tested the reasonability of total capital costs with comparable project benchmark data. See Schedule 7 for further details. Based on our research, total capital costs were determined to be reasonable.

[F2] [redacted]

[F3] BoP costs include contracted construction costs which are based on Management's best estimates based on other projects and pricing provided by Mortenson, the selected contractor for the project. Investor's Schedule of Exhibits **C0375** (001854-3.2.1).

[F4] Inflation rate is based on Bank of Canada's core CPI rate.

[F5] [redacted]

[F6] Schedule 6.

Schedule 3K
Project Arran
Development and Construction Costs (Capacity Expansion)
Amounts in CAD 000s unless otherwise stated
As at January 21, 2010

	Notes		Dec 31, 2008	Dec 31, 2009	pre-Jan 21 2010	post Jan 21 2010	For the year ended Dec 31, 2011	2012	2013	Mar 31, 2014
			Development period						Construction period	
Capital costs	**[F1]**		[redacted]							
Development costs										
WTG costs	**[F2]**									
BoP costs	**[F3]**									
Total unlevered capital costs										
Financing costs										
Total capital costs										
Period			2.44	1.44	0.47					
Inflation rate	**[F4]**		1.15%	2.98%	0.34%					
PV factor for the period			[redacted]							
Cumula ive PV factor										
Inflated cash flows										
Inflated cash flows (excluding financing amounts)										
Historical capital expenditures										
Capital expenditures financed by equity	**[F5]**									
Capital expenditures financed by debt	**[F5]**									
LOW										
Period						0.47	1.44	2.44	3.44	4.07
PV Factor	**[F6]**	12.5%				[redacted]				
Discounted cash flows										
Sum of pre-operating cash flows		[redacted]								
Discounted cash flows (excluding financing amounts)										
Future capital expenditures										
Capital expenditures financed by equity										
Capital expenditures financed by debt	**[F5]**									
HIGH										
Period						0.47	1.44	2.44	3.44	4.07
PV Factor	**[F6]**	11 5%				[redacted]				
Discounted cash flows										
Sum of pre-operating cash flows		[redacted]								
Discounted cash flows (excluding financing amounts)										
Future capital expenditures										
Capital expenditures financed by equity										
Capital expenditures financed by debt	**[F5]**									

Notes:

[F1] We have tested the reasonability of total capital costs with comparable project benchmark data. See Schedule 7 for further details. Based on our research, total capital costs were determined to be reasonable.

[F2] [redacted]

[F3] BoP costs include contracted construction costs which are based on Management's best estimates based on other projects and pricing provided by Mortenson, the selected contractor for the project. Investor's Schedule of Exhibits **C0375** (001854-3.2.1).

[F4] Inflation rate is based on Bank of Canada's core CPI rate.

[F5] [redacted]

[F6] Schedule 6.

Schedule 3L
Project Arran
Development and Construction Costs - 2.5XL Turbines
Amounts in CAD 000s unless otherwise stated
As at November 25, 2009

	Notes		Dec 31, 2008	Dec 31, 2009	post Nov 25 2009	For the year ended Dec 31, 2010	2011	2012	2013	Mar 31, 2014
			Development period						Construction period	
Capital costs	**[F1]**		[redacted]							
Development costs										
WTG costs	**[F2]**									
BoP costs	**[F3]**									
Total unlevered capital costs (2.5XL turbine)										
Total unlevered capital costs (1.6xle turbine)	**[F7]**									
Total incremental unlevered capital costs										
Financing costs										
Total financing amounts (2.5XL turbine)										
Total financing amounts (1.6xle turbine)	**[F7]**									
Total incremental financing amounts										
Total capital costs (2.5XL turbine)										
Total capital costs (1.6xle turbine)										
Total incremental capital costs										
Period			0.60	0.05						
Inflation rate	**[F4]**		1.15%	2.98%						
PV factor for the period			[redacted]							
Cumulative PV factor										
Inflated cash flows										
LOW										
Period					0.05	0.60	1.60	2.60	3.60	4.22
PV Factor	**[F6]**	12.5%			[redacted]					
Discounted cash flows										
Sum of pre-operating cash flows		[redacted]								
Discounted cash flows (excluding financing amounts)										
Future capital expenditures										
Capital expenditures financed by equity										
Capital expenditures financed by debt	**[F5]**									
HIGH										
Period					0.05	0.60	1.60	2.60	3.60	4.22
PV Factor	**[F6]**	11.5%			[redacted]					
Discounted cash flows										
Sum of pre-operating cash flows		[redacted]								
Discounted cash flows (excluding financing amounts)										
Future capital expenditures										
Capital expenditures financed by equity										
Capital expenditures financed by debt	**[F5]**									

Notes:

[F1] We have tested the reasonability of total capital costs wi h comparable project benchmark data. See Schedule 7 for further details. Based on our research, total capital costs were determined to be reasonable.

[F2] [redacted]

[F3] BoP costs include contracted construction costs and contingency fees (of 10% of all other BoP costs) which are based on Management's best estimates based on other projects and pricing provided by Mortenson, the selected contractor for the project.

[F4] Inflation rate is based on Bank of Canada's core CPI rate.

[F5] [redacted]

[F6] Schedule 6.

[F7] Schedule 3G

Schedule 3M
Project Arran
Development and Construction Costs - 2.5XL Turbines
Amounts in CAD 000s unless otherwise stated
As at November 25, 2009

	Notes		Dec 31, 2008	Dec 31, 2009	post Nov 25 2009	For the year ended Dec 31, 2010	For the year ended Dec 31, 2011	For the year ended Dec 31, 2012	For the year ended Dec 31, 2013	Mar 31, 2014
			Development period						Construction period	
Capital costs	**[F1]**		[redacted]							
Development costs										
WTG costs	**[F2]**									
BoP costs	**[F3]**									
Total unlevered capital costs (2.5XL turbines - capacity expansion)										
Total unlevered capital costs (2.5XL turbines)	**[F7]**									
Total incremental unlevered capital costs										
Financing costs										
Total financing amounts (2.5XL turbines - capacity expansion)										
Total financing amounts (2.5XL turbines)										
Total incremental financing amounts										
Total capital costs (2.5XL turbines - capacity expansion)										
Total capital costs (2.5XL turbines)	**[F7]**									
Total incremental capital costs										
Period			0.60	0.05						
Inflation rate	**[F4]**		1.15%	2 98%						
PV factor for the period			[redacted]							
Cumulative PV factor										
Inflated cash flows										
LOW										
Period					0.05	0.60	1.60	2.60	3.60	4.22
PV Factor	**[F6]**	12.5%			[redacted]					
Discounted cash flows		[redacted]								
Sum of pre-operating cash flows										
Discounted cash flows (excluding financing amounts)										
Future capital expenditures										
Capital expenditures financed by equity										
Capital expenditures financed by debt	**[F5]**									
HIGH										
Period					0.05	0.60	1.60	2.60	3.60	4.22
PV Factor	**[F6]**	11 5%			[redacted]					
Discounted cash flows		[redacted]								
Sum of pre-operating cash flows										
Discounted cash flows (excluding financing amounts)										
Future capital expenditures										
Capital expenditures financed by equity										
Capital expenditures financed by debt	**[F5]**									

Notes:

[F1] We have tested the reasonability of total capital costs wi h comparable project benchmark data. See Schedule 7 for further details. Based on our research, total capital costs were determined to be reasonable.

[F2] [redacted]

[F3] BoP costs include contracted construction costs and contingency fees (of 10% of all other BoP costs) which are based on Management's best estimates based on other projects and pricing provided by Mortenson, the selected contractor for the project.

[F4] Inflation rate is based on Bank of Canada's core CPI rate.

[F5] [redacted]

[F6] Schedule 6.

[F7] Schedule 3L

Schedule 4A
Project Summerhill
Summary
Amounts in CAD 000s unless otherwise stated
As at May 29, 2010

	Notes		Economic Losses		
			Low	Midpoint	High
NAFTA 1102, NAFTA 1103 & NAFTA 1105	**[F1]**				
Base Case		**Schedule 4B**	56,344	60,202	64,060
Economic Development Adder		**Schedule 4C**	3,539	3,698	3,858
Capacity expansion		**Schedule 4D**	6,453	6,863	7,273
Economic Development Adder applicable to capacity expansion		**Schedule 4D**	342	358	373
NAFTA 1106			11,733	12,271	12,809
Total			78,411	83,392	88,374
NAFTA 1106					
Base Case		**Schedule 4E**	10,638	11,119	11,600
Economic Development Adder		**Schedule 4F**	24	26	29
Capacity expansion		**Schedule 4G**	1,057	1,111	1,166
Economic Development Adder applicable to capacity expansion		**Schedule 4G**	14	15	15
Total			11,733	12,271	12,809
Total claim (pre-tax)			**78,411**	**83,392**	**88,374**
Total claim, rounded			**78,000**	**83,000**	**88,000**

Notes

[F1] Please refer to Sections 1.12 to 1.27 for further details related to the claims.

Schedule 4B
Project Summerhill
Discounted Cash Flows - NAFTA Article 1102, 1103 & 1105 (Base Case)
Amounts in CAD 000s unless otherwise stated
As at May 29, 2010

	Notes		2013	2014	2015	2016	2021	2022	2023	2032	2033	2034
			For the year ended December 31,									
Revenue												
Price	[F1]	0.42%	[redacted]									
Production (000s MWh)	[F2]											
Total revenue												
Operating expenses	[F3]											
Land Payments		2.20%										
Asset manager	[F4]											
Unplanned maintenance	[F4]											
Planned maintenance	[F4]											
Transmission charge	[F4]											
BOP maintenance	[F4]											
Property taxes	[F4]											
Insurance	[F4]											
Total operating expenses												
EBITDA												
Less: Interest expense												
EX-IM loan interest	[F5]											
Term loan interest	[F5]											
Net cash flows after interest												
Less: Taxes @ 25.00%	[F6]											
After-tax cash flow												
Less: Debt principal repayments												
EX-IM loan principal payment	[F5]											
Term loan principal payment	[F5]											
Levered free cash flows												
LOW												
Percent of year remaining			100%	100%	100%	100%	100%	100%	100%	100%	100%	100%
Period			[redacted]									
Discount rate	[F7]											
Cumulative PV factor												
Discounted operating cash flows												
Equity-financed capital expenditures	[F8]											
Net present value of cash flows		[redacted]										
Gross pre-tax net present value of cash flows												
HIGH												
Discount rate	[F7]											
Cumulative PV factor												
Discounted operating cash flows												
Equity-financed capital expenditures	[F8]											
Net present value of cash flows												
Gross pre-tax net present value of cash flows												

Notes:

[F1] Power price based on FIT application.
[F2] Based on Management's best estimate and considering the relation to the TTD project.
[F3] We have tested the reasonability of total operating expenses with comparable project benchmark data. Land payments are based on the agreed terms of the land options. See Schedule 7 for further details. Based on our research, total operating expenses were determined to be reasonable.
[F4] We have assumed that these expenses would increase annually by 2.2%, based on inflation forecasts from Economic Intelligence Unit.
[F5] Schedule 4H.
[F6] Tax rates are based on the substantively enacted tax rates as at the Valuation Date.
Tax expense:

			2013	2014	2015	2016	2021	2022	2023	2032	2033	2034
Net cash flows after interest	**[A]**		[redacted]									
Less: tax deductions	**[B]**											
Taxable income	**[A] + [B]**											
Tax expense		25.00%										

[B] The tax deductions/adjustments are quantified by considering the tax attributes available for renewable energy projects. Specifically, we have considered capital cost allowances and Canadian Renewable Conservation Expenses.

[F7] Schedule 6
[F8] Schedule 4J
[F9] For presentation purposes, we have ommited the visibility of certain years of the forecast.

Schedule 4C
Project Summerhill
Discounted Cash Flows - NAFTA Article 1102, 1103 & 1105 (Economic Development Adder)
Amounts in CAD 000s unless otherwise stated
As at May 29, 2010

	Notes		2013	2014	2015	2016	2021	2022	2023	2032	2033	2034
			For the year ended December 31,									
Revenue												
Price	[F1]	0.42%	[redacted]									
Production (000s MWh)	[F2]											
Total revenue												
Operating expenses	[F3]											
Land Payments		2 20%										
Asset manager	[F4]											
Unplanned maintenance	[F4]											
Planned maintenance	[F4]											
Transmission charge	[F4]											
BOP maintenance	[F4]											
Property taxes	[F4]											
Insurance	[F4]											
Total operating expenses												
EBITDA												
Less Interest expense												
EX- M loan interest	[F5]											
Term loan interest	[F5]											
Net cash flows after interest												
Less: Taxes @ 25.00%	[F6]											
After-tax cash flow												
Less Debt principal repayments												
EX- M loan principal payment	[F5]											
Term loan principal payment	[F5]											
Levered free cash flows												
LOW												
Percent of year remaining			100%	100%	100%	100%	100%	100%	100%	100%	100%	100%
Period			3.1	4.1	5.1	6.1	11.1	12.1	13.1	22.1	23.1	24.1
Discount rate	[F7]		12.5%	12.5%	12.3%	12.0%	10 6%	10.3%	9.9%	5.8%	5 8%	5.8%
Cumulative PV factor			0.69	0.62	0.55	0.49	0 29	0.26	0.24	0.12	0.11	0.11
Discounted operating cash flows		[redacted]										
Equity-financed capital expenditures	[F8]											
Net present value of cash flows												
Less: NAFTA 1102/1103/1105 - Base Case	[F9]											
NPV of incremental cash flows												
Gross pre-tax NPV of incremental cash flows												
HIGH												
Discount rate	[F7]		11.5%	11.5%	11.3%	11.1%	9 8%	9.5%	9.2%	5.5%	5 5%	5.5%
Cumulative PV factor			0.71	0.64	0.58	0.52	0 32	0.29	0.26	0.14	0.13	0.13
Discounted operating cash flows		[redacted]										
Equity-financed capital expenditures	[F8]											
Net present value of cash flows												
Less: NAFTA 1102/1103/1105 - Base Case	[F9]											
NPV of incremental cash flows												
Gross pre-tax NPV of incremental cash flows												

Notes

[F1] Power price based on FIT application. In this scenario we have added the Economic Development Adder of 0.27 cents per kWh that was offered to Samsung in the Amended GEIA. Investor's Schedule of Exhibit **C0282** (4403).
[F2] Based on Management's best estimate and considering the relation to the TTD project.
[F3] We have tested the reasonability of total operating expenses with comparable project benchmark data. See Schedule 7 for further details. Based on our research, total operating expenses were determined to be reasonable.
[F4] We have assumed that these expenses would increase annually by 2.2%, based on inflation forecasts from Economic Intelligence Unit.
[F5] Schedule 4H.
[F6] Tax rates are based on the substantively enacted tax rates as at the Valuation Date.
Tax expense:

			2013	2014	2015	2016	2021	2022	2023	2032	2033	2034
Net cash flows after interest	**[A]**		[redacted]									
Less: tax deduction	**[B]**											
Taxable income	**[A] + [B]**											
Tax expense		25 00%										

[B] The tax deductions/adjustments are quantified by considering the tax attributes available for renewable energy projects. Specifically, we have considered capital cost allowances and Canadian Renewable Cc
[F7] Schedule 6
[F8] Schedule 4J
[F9] Schedule 4B.
[F10] For presentation purposes, we have ommited the visibility of certain years of the forecast.

Schedule 4D
Project Summerhill
Discounted Cash Flows - NAFTA Article 1102, 1103 & 1105 (Expansion)
Amounts in CAD 000s unless otherwise stated
As at May 29, 2010

	Notes		2013	2014	2015	2016	2021	2022	2023	2032	2033	2034
			For the year ended December 31,									
Revenue												
Price	[F1]	0.42%			145	146	149	149	150	156	156	157
Production (000s MWh)	[F2]		[redacted]									
Total revenue												
Operating expenses	[F3]											
Land Payments		2.20%										
Asset manager	[F4]											
Unplanned maintenance	[F4]											
Planned maintenance	[F4]											
Transmission charge	[F4]											
BOP maintenance	[F4]											
Property taxes	[F4]											
Insurance	[F4]											
Total operating expenses												
EBITDA												
Less Interest expense												
EX-IM loan interest	[F5]											
Term loan interest	[F5]											
Net cash flows after interest												
Less: Taxes @ 25.00%	[F6]											
After-tax cash flow												
Less Debt principal repayments												
EX-IM loan principal payment	[F5]											
Term loan principal payment	[F5]											
Levered free cash flows												
LOW												
Percent of year remaining												
Period												
Discount rate	[F7]											
Cumulative PV factor												
Discounted operating cash flows												
Equity-financed capital expenditures		**Schedule 4J**										
Net present value of cash flows		[redacted]										
Less: NAFTA 1102/1103/1105 - Base Case	[F8]											
NPV of incremental cash flows												
Gross pre-tax NPV of incremental cash flows												
Including Economic Development Adder												
NPV of EDA on capacity expansion	[F9]											
Less: NAFTA 1102/1103/1105 - EDA	[F10]											
NPV of incremental cash flows												
Gross pre-tax NPV of incremental cash flows												

Schedule 4D
Project Summerhill
Discounted Cash Flows - NAFTA Article 1102, 1103 & 1105 (Expansion)
Amounts in CAD 000s unless otherwise stated
As at May 29, 2010

			For the year ended December 31,									
	Notes		**2013**	**2014**	**2015**	**2016**	**2021**	**2022**	**2023**	**2032**	**2033**	**2034**
HIGH												
Discount rate	**[F7]**		[redacted]									
Cumulative PV factor												
Discounted operating cash flows												
Equity-financed capital expenditures		**Schedule 4J**										
Net present value of cash flows		[redacted]										
Less: NAFTA 1102/1103/1105 - Base Case	**[F8]**											
NPV of incremental cash flows												
Gross pre-tax net present value of cash flows												
Including Economic Development Adder												
NPV of EDA on capacity expansion	**[F9]**											
Less: NAFTA 1102/1103/1105 - EDA	**[F10]**											
NPV of incremental cash flows												
Gross pre-tax NPV of incremental cash flows												

Notes

[F1] Power price based on FIT application. In this scenario we have added the Economic Development Adder of 0 27 cents per kWh that was offered to Samsung in the Amended GEIA. Investor's Schedule of Exhibits **C0282** (4403).
[F2] Based on Management's best estimate and considering the relation to the TTD project.
[F3] We have tested the reasonability of total operating expenses with comparable project benchmark data. See Schedule 7 for further details. Based on our research, total operating expenses were determined to be reasonable.
[F4] Assumed to be a fixed cost and therefore does not increase with the increase in capacity.
[F5] Schedule 4H.
[F6] Tax rates are based on the substantively enacted tax rates as at the Valuation Date.
Tax expense:

			[redacted]
Net cash flows after interest	**[A]**		
Less: tax deductions	**[B]**		
Taxable income	**[A] + [B]**		
Tax expense		25.00%	

[B] The tax deductions/adjustments are quantified by considering the tax attributes available for renewable energy projects. Specifically, we have considered capital cost allowances and Canadian Renewable Conservation Expenses.
[F7] Schedule 6.
[F8] Schedule 4B.
[F9] We have calculated the additional Economic Losses related to the Economic Development Adder on the 10% capacity expansion by increasing the price (as used in Schedule 4C). The operating, capital and financing costs remain the same.
[F10] Schedule 4C.
[F11] For presentation purposes, we have ommited the visibility of certain years of the forecast.

Schedule 4E
Project Summerhill
Discounted Cash Flows - NAFTA Article 1106 (Base Case)
Amounts in CAD 000s unless otherwise stated
As at May 29, 2010

	Notes		For the year ended December 31, 2013	2014	2015	2016	2021	2022	2023	2032	2033	2034
Revenue												
Price	[F1]	0.42%			145	146	149	149	150	156	156	157
Produc ion (000s MWh)	[F2]		[redacted]									
Total revenue			[redacted]									
Operating expenses	[F3]		[redacted]									
Land Payments		2.20%	[redacted]									
Asset manager	[F4]		[redacted]									
Unplanned maintenance	[F4]		[redacted]									
Planned maintenance	[F4]		[redacted]									
Transmission charge	[F4]		[redacted]									
BOP maintenance	[F4]		[redacted]									
Property taxes	[F4]		[redacted]									
Insurance	[F4]		[redacted]									
Total operating expenses			[redacted]									
EBITDA			[redacted]									
Less: Interest expense			[redacted]									
EX-IM loan interest	[F5]		[redacted]									
Term loan interest	[F5]		[redacted]									
Net cash flows after interest			[redacted]									
Less: Taxes @ 25.00%	[F6]		[redacted]									
After-tax cash flow			[redacted]									
Less: Capital expenditures			[redacted]									
Less: Debt principal repayments			[redacted]									
EX-IM loan principal payment	[F5]		[redacted]									
Term loan principal payment	[F5]		[redacted]									
Levered free cash flows			[redacted]									
NAFTA Article 1106 - Base Case			[redacted]									
NAFTA Article 1102/1103/1105 - Base Case	[F7]		[redacted]									
Incremental levered free cash flows			[redacted]									
LOW			[redacted]									
Percent of year remaining			[redacted]									
Period			[redacted]									
Discount rate	[F8]		[redacted]									
Cumulative PV factor			[redacted]									
Discounted incremental operating cash flows			[redacted]									
Incremental equity-financed capital expenditures	[F9]	[redacted]	[redacted]									
Net present value of cash flows		[redacted]	[redacted]									
Gross pre-tax NPV of incremental cash flows		[redacted]	[redacted]									
HIGH		[redacted]	[redacted]									
Discount rate	[F8]	[redacted]	[redacted]									
Cumulative PV factor		[redacted]	[redacted]									
Discounted incremental operating cash flows		[redacted]	[redacted]									
Incremental equity-financed capital expenditures	[F9]	[redacted]	[redacted]									
Net present value of cash flows		[redacted]	[redacted]									
Gross pre-tax NPV of incremental cash flows		[redacted]	[redacted]									

Notes:

[F1] Power price based on FIT application.
[F2] Based on Management's best es imate and considering the relation to he TTD project.
[F3] We have tested the reasonability of total operating expenses wi h comparable project benchmark data. See Schedule 7 for further details. Based on our research, total operating expenses were determined to be reaso
[F4] We have assumed that these expenses would increase annually by 2.2%, based on inflation forecasts from Economic Intelligence Unit.
[F5] Schedule 4I.
[F6] Tax rates are based on the substan ively enacted tax rates as at the Valuation Date.
Tax expense:

			2013	2014	2015	2016	2021	2022	2023	2032	2033	2034
Net cash flows after interest	**[A]**		[redacted]									
Less: tax deductions	**[B]**											
Taxable income	**[A] + [B]**											
Tax expense		25.00%										

[B] The tax deductions/adjustments are quan ified by considering the tax attributes available for renewable energy projects. Specifically, we have considered capital cost allowances and Canadian Renewable Conserva
[F7] Schedule 4B.
[F8] Schedule 6.
[F9] Schedul 4L.
[F10] For presentation purposes, we have ommited the visibility of certain years of the forecast.

Schedule 4F
Project Summerhill
Discounted Cash Flows - NAFTA Article 1106 (Economic Development Adder)
Amounts in CAD 000s unless otherwise stated
As at May 29, 2010

	Notes		For the year ended December 31, 2013	2014	2015	2016	2021	2022	2023	2032	2033	2034
Revenue												
Price	**[F1]**	0.42%			148	148	151	152	153	158	159	160
Production (000s MWh)	**[F2]**		[redacted]									
Total revenue			[redacted]									
Operating expenses	**[F3]**		[redacted]									
Land Payments		2.20%	[redacted]									
Asset manager	**[F4]**		[redacted]									
Unplanned maintenance	**[F4]**		[redacted]									
Planned maintenance	**[F4]**		[redacted]									
Transmission charge	**[F4]**		[redacted]									
BOP maintenance	**[F4]**		[redacted]									
Property taxes	**[F4]**		[redacted]									
Insurance	**[F4]**		[redacted]									
Total operating expenses			[redacted]									
EBITDA			[redacted]									
Less: Interest expense			[redacted]									
EX-IM loan interest	**[F5]**	**Schedule 4I**	[redacted]									
Term loan interest	**[F5]**	**Schedule 4I**	[redacted]									
Net cash flows after interest			[redacted]									
Less: Taxes @ 25.00%	**[F6]**		[redacted]									
After-tax cash flow			[redacted]									
Less: Debt principal repayments			[redacted]									
EX-IM loan principal payment	**[F5]**		[redacted]									
Term loan principal payment	**[F5]**		[redacted]									
Levered free cash flows			[redacted]									
NAFTA Article 1106 - EDA			[redacted]									
NAFTA Article 1106 - Base Case	**[F7]**		[redacted]									
Incremental levered free cash flows			[redacted]									
LOW			[redacted]									
Percent of year remaining			[redacted]									
Period			[redacted]									
Discount rate	**[F8]**		[redacted]									
Cumulative PV factor			[redacted]									
Discounted incremental operating cash flows			[redacted]									
Net present value of incremental cash flows		[redacted]										
Less: NAFTA Article 1102/1103/1105 - EDA	**[F9]**	[redacted]										
NPV of incremental cash flows		[redacted]										
Gross pre-tax NPV of incremental cash flows		[redacted]										
HIGH		[redacted]										
Discount rate	**[F8]**	[redacted]										
Cumulative PV factor		[redacted]										
Discounted incremental operating cash flows		[redacted]										
Net present value of cash flows		[redacted]										
Less: NAFTA Article 1102/1103/1105 - EDA	**[F9]**	[redacted]										
NPV of incremental cash flows		[redacted]										
Gross pre-tax NPV of incremental cash flows		[redacted]										

Notes:

[F1] Power price based on FIT applica ion. In this scenario we have added he Economic Development Adder of 0.27 cents per kWh that was offered to Samsung in the Amended GEIA. Investor's Schedule of Exhibits **C0282** (4403).

[F2] Based on Management's best estimate and considering the relation to the TTD project.

[F3] We have tested the reasonability of total operating expenses with comparable project benchmark data. See Schedule 7 for further details. Based on our research, total operating expenses were determined to be reas

[F4] We have assumed that hese expenses would increase annually by 2.2%, based on inflation forecasts from Economic Intelligence Unit.

[F5] Schedule 4I.

[F6] Tax rates are based on the substantively enacted tax rates as at the Valuation Date.

Tax expense:

			2013	**2014**	**2015**	**2016**	**2021**	**2022**	**2023**	**2032**	**2033**	**2034**
Net cash flows after interest	**[A]**		[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Less: tax deductions	**[B]**		[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Taxable income	**[A] + [B]**		[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Tax expense		25.00%	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]

[B] The tax deductions/adjustments are quan ified by considering the tax attributes available for renewable energy projects. Specifically, we have considered capital cost allowances and Canadian Renewable Conserva

[F7] Schedule 4E.

[F8] Schedule 6.

[F9] Schedule 4C.

[F10] For presentation purposes, we have ommited the visibility of certain years of the forecast.

Schedule 4G
Project Summerhill
Discounted Cash Flows - NAFTA Article 1106 (Expansion)
Amounts in CAD 000s unless otherwise stated
As at May 29, 2010

	Notes		For the year ended December 31, 2013	2014	2015	2016	2021	2022	2023	2032	2033	2034
Revenue												
Price	[F1]	0.42%			145	146	149	149	150	156	156	157
Production (000s MWh)	[F2]		[redacted]									
Total revenue												
Operating expenses	[F3]											
Land Payments		2.20%										
Asset manager	[F4]											
Unplanned maintenance	[F4]											
Planned maintenance	[F4]											
Transmission charge	[F4]											
BOP maintenance	[F4]											
Property taxes	[F4]											
Insurance	[F4]											
Total operating expenses												
EBITDA												
Less: Interest expense												
EX- M loan interest	[F5]											
Term loan interest	[F5]											
Net cash flows after interest												
Less: Taxes @ 25.00%	[F6]											
After-tax cash flow												
Less: Debt principal repayments												
EX- M loan principal payment	[F5]											
Term loan principal payment	[F5]											
Levered free cash flows												
NAFTA Article 1106 - Capacity Expansion												
NAFTA Article 1106 - Base Case	[F7]											
Incremental levered free cash flows												
LOW												
Percent of year remaining												
Period												
Discount rate	[F8]											
Cumulative PV factor												
Discounted incremental operating cash flows												
Incremental equity-financed capital expenditures	[F9]											
Net present value of cash flows		[redacted]										
Less: NAFTA Article 1102/1103/1105 - Capacity Expansion	[F10]											
NPV of incremental cash flows												
Gross pre-tax NPV of incremental cash flows												
Including Economic Development Adder												
NPV of EDA on capacity expansion	[F11]											
Less: (NAFTA Article 1102/1103 - Capacity Expansion with EDA	[F10]											
NPV of incremental cash flows												
Gross pre-tax NPV of incremental cash flows												

Schedule 4G
Project Summerhill
Discounted Cash Flows - NAFTA Article 1106 (Expansion)
Amounts in CAD 000s unless otherwise stated
As at May 29, 2010

	Notes	For the year ended December 31, 2013	2014	2015	2016	2021	2022	2023	2032	2033	2034
HIGH											
Discount rate	**[F8]**	[redacted]									
Cumulative PV factor		[redacted]									
Discounted incremental operating cash flows		[redacted]									
Incremental equity-financed capital expenditures	**[F9]**	[redacted]									
Net present value of cash flows		[redacted]									
Less: NAFTA Article 1102/1103/1105 - Capacity Expansion	**[F10]**	[redacted]									
NPV of incremental cash flows		[redacted]									
Gross pre-tax NPV of incremental cash flows		[redacted]									
Including Economic Development Adder											
NPV of EDA on capacity expansion	**[F11]**	[redacted]									
Less: NAFTA Article 1102/1103/1105 - Capacity Expansion with EDA	**[F10]**	[redacted]									
NPV of incremental cash flows		[redacted]									
Gross pre-tax NPV of incremental cash flows		[redacted]									

Notes:

[F1] Power price based on FIT application. In this scenario we have added the Economic Development Adder of 0.27 cents per kWh that was offered to Samsung in the Amended GEIA. Investor's Schedule of Exhibits **C0282** (4403).
[F2] Based on Management's best estimate and considering he rela ion to the TTD project.
[F3] We have tested the reasonability of total operating expenses with comparable project benchmark data. See Schedule 7 for further details. Based on our research, total operating expenses were determined to be reasonable.
[F4] We have assumed that these expenses would increase annually by 2.2%, based on inflation forecasts from Economic Intelligence Unit.
[F5] Schedule 4I.
[F6] Tax rates are based on the substantively enacted tax rates as at the Valua ion Date.
Tax expense:

			2013	2014	2015	2016	2021	2022	2023	2032	2033	2034
Net cash flows after interest	**[A]**		[redacted]									
Less: tax deductions	**[B]**		[redacted]									
Taxable income	**[A] + [B]**		[redacted]									
Tax expense		25.00%	[redacted]									

[B] The tax deduc ions/adjustments are quantified by considering the tax attributes available for renewable energy projects. Specifically, we have considered capital cost allowances and Canadian Renewable Conservation Expenses.

[F7] Schedule 4E.
[F8] Schedule 6.
[F9] Schedule 4M
[F10] Schedule 4D
[F11] We have calculated the additional Economic Losses related to the Economic Development Adder on the 10% capacity expansion by increasing the price (as used in Schedule 2F). The operating, capital and financing costs remain the same.
[F12] For presentation purposes, we have ommited the visibility of certain years of the forecast.

Schedule 4H
Project Summerhill
Financing - 1.6xle Turbines
Amounts in CAD 000s unless otherwise stated
As at May 29, 2010

	Notes	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032
		For the year ended December 31,																		
EX-IM Loan Amortization	[F1]	[redacted]																		
Beginning balance																				
Less: Principal repayment																				
Ending balance																				
Interest																				
Total Principal and interest																				
Ending balance/kW																				
Term Loan Amortization	[F2]																			
Beginning balance																				
Less: Principal repayment																				
Ending balance																				
Interest																				
Total Principal and interest																				
Ending balance/kW																				

Notes
[F1] [redacted]
[F2]

Financing for the 10% increase in capacity

EX-IM Loan Amortization	[redacted]
Beginning balance	
Less: Principal repayment	
Ending balance	
Interest	
Term Loan Amortization	
Beginning balance	
Less: Principal repayment	
Ending balance	
Interest	

Schedule 4I
Project Summerhill
Financing - 2.5XL Turbines
Amounts in CAD 000s unless otherwise stated
As at May 29, 2010

	Notes	For the year ended December 31,																		
		2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032
EX-IM Loan Amortization	[F1]	[redacted]																		
Beginning balance																				
Less: Principal repayment																				
Ending balance																				
Interest																				
Total Principal and interest																				
Ending balance/kW																				
Term Loan Amortization	[F2]																			
Beginning balance																				
Less: Principal repayment																				
Ending balance																				
Interest																				
Total Principal and interest																				
Ending balance/kW																				

Notes
[F1] [redacted]
[F2] [redacted]

Financing for the 10% increase in capacity

EX-IM Loan Amortization	[redacted]
Beginning balance	
Less: Principal repayment	
Ending balance	
Interest	
Term Loan Amortization	
Beginning balance	
Less: Principal repayment	
Ending balance	
Interest	

Schedule 4J
Project Summerhill
Development and Construction Costs - 1.6xle Turbines
Amounts in CAD 000s unless otherwise stated
As at May 29, 2010

	Notes		For the year ended December 31, 2013	2014
			Development period	Construction period
Capital costs	**[F1]**		[redacted]	
Development costs				
WTG costs	**[F2]**			
BoP costs	**[F3]**			
Total unlevered capital costs				
Financing costs				
Total capital costs				
LOW				
Period				
PV Factor	**[F5]**	12.5%		
Discounted cash flows				
Sum of development and construction costs		[redacted]		
Discounted cash flows (excluding financing amounts)				
Future capital expenditures				
Capital expenditures financed by equity	**[F4]**			
Capital expenditures financed by debt				
HIGH				
Period				
PV Factor	**[F5]**	11.5%		
Discounted cash flows				
Sum of development and construction costs		[redacted]		
Discounted cash flows (excluding financing amounts)				
Future capital expenditures				
Capital expenditures financed by equity	**[F4]**			
Capital expenditures financed by debt				

Notes:

[F1] We have tested the reasonability of total capital costs with comparable project benchmark data. See Schedule 7 for fur her details. Based on our research, total capital costs were determined to be reasonable.

[F2] WTG costs include direct costs related to the wind turbines which are based on Management's best estimates from other projects and pricing provided by GE. The most substantial cost included in this category is the cost of the wind turbines of $2,230,000 for each 1.6xle wind turbine. Investor's Schedule of Exhibits **C0380** (002024 page 7).

[F3] BoP costs include contracted construc ion costs and contingency fees (of 10% of all other BoP costs) which are based on Management's best estimates based on other projects and pricing provided by Mortenson, the selected contractor for the project. The contracted construction costs for Summerhill were determined by applying the contracted construction cost ($/kWh) for Arran to Summerhill's annual energy production (001856-3 2.3).

[F4] Based on discussions with Management, we have assumed 100% equity financing for the development period and 80%/20% debt/equity financing split for the construction period, which is also consistent with our market research.

[F5] Schedule 6.

Schedule 4K
Project Summerhill
Development and Construction Costs (Capacity Expansion)
Amounts in CAD 000s unless otherwise stated
As at May 29, 2010

	Notes		For the year ended December 31, 2013	2014
			Development period	Construction period
Capital costs	[F1]		[redacted]	
Development costs				
WTG costs	[F2]			
BoP costs	[F3]			
Total unlevered capital costs				
Financing costs				
Discounted cash flows (excluding financing amounts)				
LOW				
Period			3.09	4.09
PV Factor	[F5]	12.5%	[redacted]	
Discounted cash flows				
Sum of development and construction costs		[redacted]		
Discounted cash flows (excluding financing amounts)				
Future capital expenditures				
Capital expenditures financed by equity	[F4]			
Capital expenditures financed by debt				
HIGH				
Period			3.09	4.09
PV Factor	[F5]	11.5%	[redacted]	
Discounted cash flows				
Sum of development and construction costs		[redacted]		
Discounted cash flows (excluding financing amounts)				
Future capital expenditures				
Capital expenditures financed by equity	[F4]			
Capital expenditures financed by debt				

Notes:

[F1] We have tested the reasonability of total capital costs wi h comparable project benchmark data. See Schedule 7 for further details. Based on our research, total capital costs were determined to be reasonable.

[F2] WTG costs include direct costs related to the wind turbines which are based on Management's best estimates from other projects and pricing provided by GE. The most substantial cost included in this category is the cost of the wind turbines of $2,230,000 for each 1.6xle wind turbine. Investor's Schedule of Exhibits **C0380** (002024 page 7).

[F3] BoP costs include contracted construction costs and contingency fees which are based on Management's best estimates based on other projects and pricing provided by Mortenson, the selected contractor for the project. The contracted construction costs for Summerhill were determined by applying the contracted construction cost ($/kWh) for Arran to Summerhill's annual energy production. Investor's Schedule of Exhibits **C0375 (**001854-3.2.1).

[F4] Based on discussions with Management, we have assumed 100% equity financing for the development period and 80%/20% debt/equity financing split for the construction period, which is also consistent with our market research.

[F5] Schedule 6.

Schedule 4L
Project Summerhill
Development and Construction Costs - 2.5XL Turbines
Amounts in CAD 000s unless otherwise stated
As at May 29, 2010

	Notes		For the year ended December 31, 2013	2014
			Development period	Construction period
Capital costs	**[F1]**		[redacted]	
Development costs				
WTG costs	**[F2]**			
BoP costs	**[F3]**			
Total unlevered capital costs (2.5XL turbine)				
Total unlevered capital costs (1.6xle turbine)				
Total incremental unlevered capital costs				
Financing costs				
Total financing amounts (2.5XL turbine)				
Total financing amounts (1.6xle turbine)				
Total incremental financing amounts				
Total capital costs (2.5XL turbine)				
Total capital costs (1.6xle turbine)				
Total incremental capital costs				
LOW				
Period			3.09	4.09
PV Factor	**[F5]**	12.5%	[redacted]	
Discounted cash flows		[redacted]		
Sum of development and construction costs				
Discounted cash flows (excluding financing amounts)				
Future capital expenditures				
Capital expenditures financed by equity				
Capital expenditures financed by debt	**[F4]**			
HIGH				
Period			3.09	4.09
PV Factor	**[F5]**	11.5%	[redacted]	
Discounted cash flows		[redacted]		
Sum of development and construction costs				
Discounted cash flows (excluding financing amounts)				
Future capital expenditures				
Capital expenditures financed by equity				
Capital expenditures financed by debt	**[F4]**			

Notes:

[F1] We have tested the reasonability of total capital costs with comparable project benchmark data. See Schedule 7 for further details. Based on our research, total capital costs were determined to be reasonable.

[F2] [redacted]

[F3] BoP costs include contracted construction costs and contingency fees which are based on Management's best estimates based on other projects and pricing provided by Mortenson, the selected contractor for the project. The contracted construction costs for Summerhill were determined by applying the contracted construction cost ($/kWh) for Arran to Summerhill's annual energy production. Investor's Schedule of Exhibits **C0375 (**001854-3.2.1).

[F4] [redacted]

[F5] Schedule 6.

Schedule 4M
Project Summerhill
Development and Construction Costs - 2.5XL Turbines (Capacity Expansion)
Amounts in CAD 000s unless otherwise stated
As at May 29, 2010

	Notes		For the year ended December 31, 2013	2014
			Development period	Construction period
Capital costs	**[F1]**		[redacted]	
Development costs				
WTG costs	**[F2]**			
BoP costs	**[F3]**			
Total unlevered capital costs (2.5XL turbines - capacity expansion)				
Total unlevered capital costs (2.5XL turbines)				
Total incremental unlevered capital costs				
Financing costs				
Total financing amounts (2.5XL turbines - capacity expansion)				
Total financing amounts (2.5XL turbines)				
Total incremental financing amounts				
Total capital costs (2.5XL turbines - capacity expansion)				
Total capital costs (2.5XL turbines)				
Total incremental capital costs				
LOW				
Period			3.09	4.09
PV Factor	**[F5]**	12.5%	[redacted]	
Discounted cash flows				
Sum of development and construction costs		[redacted]		
Discounted cash flows (excluding financing amounts)				
Future capital expenditures				
Capital expenditures financed by equity	**[F4]**			
Capital expenditures financed by debt				
HIGH				
Period			3.09	4.09
PV Factor	**[F5]**	11.5%	[redacted]	
Discounted cash flows				
Sum of development and construction costs		[redacted]		
Discounted cash flows (excluding financing amounts)				
Future capital expenditures				
Capital expenditures financed by equity		**[F4]**		
Capital expenditures financed by debt				

Notes:

[F1] We have tested the reasonability of total capital costs with comparable project benchmark data. See Schedule 7 for further details. Based on our research, total capital costs were determined to be reasonable.

[F2] [redacted]

[F3] BoP costs include contracted construction costs and contingency fees which are based on Management's best estimates based on other projects and pricing provided by Mortenson, the selected contractor for the project. The contracted construction costs for Summerhill were determined by applying the contracted construction cost ($/kWh) for Arran to Summerhill's annual energy production. Investor's Schedule of Exhibits **C0375 (**001854-3.2.1).

[F4] [redacted]

[F5] Schedule 6.

Schedule 5A
Project North Bruce
Summary
Amounts in CAD 000s unless otherwise stated
As at May 29, 2010

	Notes		Economic Losses		
			Low	Midpoint	High
NAFTA 1102, NAFTA 1103 & NAFTA 1105	**[F1]**				
Base Case		**Schedule 5B**	96,066	102,995	109,923
Economic Development Adder		**Schedule 5C**	6,905	7,215	7,526
Capacity expansion		**Schedule 5D**	9,800	10,503	11,207
Economic Development Adder applicable to capacity expansion		**Schedule 5D**	597	622	648
NAFTA 1106			48,794	51,020	53,247
Total			113,367	121,335	129,304
NAFTA 1106					
Base Case		**Schedule 5E**	43,398	45,378	47,358
Economic Development Adder		**Schedule 5F**	296	313	330
Capacity expansion		**Schedule 5G**	4,976	5,198	5,420
Economic Development Adder applicable to capacity expansion		**Schedule 5G**	124	131	138
Total			48,794	51,020	53,247
Total claim (pre-tax)			**113,367**	**121,335**	**129,304**
Total claim, rounded			**113,000**	**121,000**	**129,000**

Notes
[F1] Please refer to Sections 1.12 to 1.27 for further details related to the claims.

Schedule 5B
Project North Bruce
Discounted Cash Flows - NAFTA Article 1102, 1103 & 1105 (Base Case)
Amounts in CAD 000s unless otherwise stated
As at May 29, 2010

	Notes		2013	2014	2015	2016	2022	2023	2032	2033	2034
			For the year ended December 31,								
Revenue											
Price	[F1]	0.42%			145	146	149	150	156	156	157
Production (000s MWh)	[F2]		[redacted]								
Total revenue			[redacted]								
Operating expenses	[F3]		[redacted]								
Land Payments [redacted]		2.20%	[redacted]								
Asset manager	[F4]		[redacted]								
Unplanned maintenance	[F4]		[redacted]								
Planned maintenance	[F4]		[redacted]								
Transmission charge	[F4]		[redacted]								
BOP maintenance	[F4]		[redacted]								
Property taxes	[F4]		[redacted]								
Insurance	[F4]		[redacted]								
Total operating expenses			[redacted]								
EBITDA			[redacted]								
Less: Interest expense			[redacted]								
EX-IM loan interest	[F5]		[redacted]								
Term loan interest	[F5]		[redacted]								
Net cash flow after interest			[redacted]								
Less: Taxes @ 25.00%	[F6]		[redacted]								
After-tax cash flow			[redacted]								
Less: Debt principal repayments			[redacted]								
EX-IM loan principal payment	[F7]		[redacted]								
Term loan principal payment	[F7]		[redacted]								
Levered free cash flows			[redacted]								
LOW											
Percent of year remaining			100%	100%	100%	100%	100%	100%	100%	100%	100%
Period			[redacted]								
Discount rate			[redacted]								
Cumula ive PV factor			[redacted]								
Discounted operating cash flows			[redacted]								
Equity-financed capital expenditures		[F8]	[redacted]								
Net present value of cash flows		[redacted]	[redacted]								
Gross pre-tax net present value of cash flows		[redacted]	[redacted]								
HIGH		[redacted]	[redacted]								
Discount rate		[redacted]	[redacted]								
Cumula ive PV factor		[redacted]	[redacted]								
Discounted operating cash flows		[redacted]	[redacted]								
Equity-financed capital expenditures		[redacted]	[redacted]								
Net present value of cash flows		[redacted]	[redacted]								
Gross pre-tax net present value of cash flows		[redacted]									

Notes:

[F1] Power price based on FIT application.
[F2] Based on Management's best estimate.
[F3] We have tested the reasonability of total operating expenses with comparable project benchmark data. See Schedule 7 for further details. Based on our research, total opera ing expenses were determined to be reasonable.
[F4] We have assumed that these expenses would increase annually by 2.2%, based on inflation forecasts from Economic Intelligence Unit.
[F5] Schedule 5H.
[F6] Tax rates are based on the substantively enacted tax rates as at the Valuation Date.
Tax expense:

			2013	**2014**	**2015**	**2016**	**2022**	**2023**	**2032**	**2033**	**2034**
Net cash flows after interest	**[A]**		[redacted]								
Less: tax deductions	**[B]**										
Taxable income	**[A] + [B]**										
Tax expense		25.00%									

[B] The tax deductions/adjustments are quantified by considering the tax attributes available for renewable energy projects. Specifically, we have considered capital cost allowances and Canadian Renewable Conservation Expenses.
[F7] Schedule 5H.
[F8] Schedule 5J.
[F9] For presentation purposes, we have ommited the visibility of certain years of the forecast.

Schedule 5C
Project North Bruce
Discounted Cash Flows - NAFTA Article 1102, 1103 & 1105 (Economic Development Adder)
Amounts in CAD 000s unless otherwise stated
As at May 29, 2010

	Notes		For the year ended December 31,								
			2013	2014	2015	2016	2022	2023	2032	2033	2034
Revenue											
Price	[F1]	0.42%	[redacted]								
Production (000s MWh)	[F2]										
Total revenue											
Operating expenses	[F3]										
Land Payments [redacted]		2.20%									
Asset manager	[F4]										
Unplanned maintenance	[F4]										
Planned maintenance	[F4]										
Transmission charge	[F4]										
BOP maintenance	[F4]										
Property taxes	[F4]										
Insurance	[F4]										
Total operating expenses											
EBITDA											
Less Interest expense											
EX- M loan interest	[F5]										
Term loan interest	[F5]										
Net cash flow after interest											
Less: Taxes @ 25.00%	[F6]										
After-tax cash flow											
Less Debt principal repayments											
EX- M loan principal payment	[F5]										
Term loan principal payment	[F5]										
Levered free cash flows											
LOW											
Percent of year remaining			100%	100%	100%	100%	100%	100%	100%	100%	100%
Period			[redacted]								
Discount rate	[F7]										
Cumulative PV factor											
Discounted operating cash flows											
Equity-financed capital expenditures		[F8]									
Net present value of cash flows											
Less: NPV NAFTA 1102/1103/1105 - Base Case	[F9										
NPV of incremental cash flows											
Gross pre-tax NPV of incremental cash flows											
HIGH											
Discount rate	[F7										
Cumulative PV factor											
Discounted operating cash flows											
Equity-financed capital expenditures											
Net present value of cash flows											
Less: NPV NAFTA 1102/1103/1105 - Base Case	[F9										
NPV of incremental cash flows											
Gross pre-tax NPV of incremental cash flows											

Notes

[F1] Power price based on FIT application. In this scenario we have added the Economic Development Adder of 0.27 cents per kWh that was offered to Samsung in the Amende
GEIA. Investor's Schedule of Exhibits **C0282** (4403).

[F2] Based on Management's best estimate.

[F3] We have tested the reasonability of total operating expenses with comparable project benchmark data. See Schedule 7 for further details. Based on our research, total operating expenses were determined to be reasonable

[F4] We have assumed that these expenses would increase annually by 2.2%, based on inflation forecasts from Economic Intelligence Unit.

[F5] Schedule 5I.

[F6] Tax rates are based on the substantively enacted tax rates as at the Valuation Date.
Tax expense:

			2013	2014	2015	2016	2022	2023	2032	2033	2034
Net cash flows after interest	**[A]**		[redacted]								
Less: tax deductions	**[B]**										
Taxable income	**A] + [B]**										
Tax expense		25.00%									

[B] The tax deductions/adjustments are quantified by considering the tax attributes available for renewable energy projects. Specifically, we have considered capital cos
allowances and Canadian Renewable Conservation Expenses.

[F7] Schedule 6.

[F8] Schedule 5J.

[F9] Schedule 5B.

[F10] For presentation purposes, we have ommited the visibility of certain years of the forecast.

Schedule 5D
Project North Bruce
Discounted Cash Flows - NAFTA Article 1102, 1103 & 1105 (Capacity Expansion)
Amounts in CAD 000s unless otherwise stated
As at May 29, 2010

	Notes		For the year ended December 31, 2013	2014	2015	2016	2022	2023	2032	2033	2034
Revenue											
Price	**[F1]**	0.42%			145	146	149	150	156	156	157
Production (000s MWh)	**[F2]**		[redacted]								
Total revenue											
Operating expenses	**[F3]**										
Land Payments [redacted]		2.20%									
Asset manager	**[F4]**										
Unplanned maintenance	**[F4]**										
Planned maintenance	**[F4]**										
Transmission charge	**[F4]**										
BOP maintenance	**[F4]**										
Property taxes	**[F4]**										
Insurance	**[F4]**										
Total operating expenses											
EBITDA											
Less Interest expense											
EX-IM loan interest	**[F5]**										
Term loan interest	**[F5]**										
Net cash flow after interest											
Less: Taxes @ 25.00%	**[F6]**										
After-tax cash flow											
Less Capital expenditures											
Less Debt principal repayments											
EX-IM loan principal payment	**[F5]**										
Term loan principal payment	**[F5]**										
Levered free cash flows											
LOW											
Percent of year remaining											
Period											
Discount rate											
Annual PV factor											
Cumulative PV factor											
Discounted operating cash flows											
Equity-financed capital expenditures	**[F7]**										
Net present value of cash flows											
Less: NPV NAFTA 1102/1103/1105 - Base Case	**[F8]**										
NPV of incremental cash flows											
Gross pre-tax net present value of cash flows											
Including Economic Development Adder											
NPV of Economic Development Adder on capacity (	**[F9]**										
Less: NPV NAFTA 1102/1103/1105 - EDA	**[F10]**										
NPV of incremental cash flows											
Gross pre-tax NPV of incremental cash flows											

Schedule 5D
Project North Bruce
Discounted Cash Flows - NAFTA Article 1102, 1103 & 1105 (Capacity Expansion)
Amounts in CAD 000s unless otherwise stated
As at May 29, 2010

	Notes	For the year ended December 31, 2013	2014	2015	2016	2022	2023	2032	2033	2034
HIGH										
Percent of year remaining		100%	100%	100%	100%	100%	100%	100%	100%	100%
Period		[redacted]								
Discount rate										
Annual PV factor										
Cumulative PV factor										
Discounted operating cash flows										
Equity-financed capital expenditures	**[F7]**									
Net present value of cash flows										
Less: NPV NAFTA 1102/1103/1105 - Base Case	**[F8]**									
NPV of incremental cash flows										
Gross pre-tax net present value of cash flows										
Including Economic Development Adder										
NPV of Economic Development Adder on capacity	**[F9]**									
Less: NPV NAFTA 1102/1103/1105 - EDA	**[F10]**									
NPV of incremental cash flows										
Gross pre-tax NPV of incremental cash flows										

Notes

[F1] Power price based on FIT application. In this scenario we have added the Economic Development Adder of 0.27 cents per kWh that was offered to Samsung in the Amended GEIA. Investor's Schedule of Exhibits **C0282** (4403).
[F2] Based on Management's best estimate.
[F3] We have tested the reasonability of total operating expenses with comparable project benchmark data. See Schedule 7 for further details. Based on our research, total operating expenses were determined to be reasonable.
[F4] We have assumed that these expenses would increase annually by 2.2%, based on inflation forecasts from Economic Intelligence Unit.
[F5] Schedule 5H.
[F6] Tax rates are based on the substantively enacted tax rates as at the Valuation Date.
Tax expense:

Net cash flows after interest	**[A]**		[redacted]
Less: tax deductions	**[B]**		
Taxable income	**[A] + [B]**		
Tax expense		25.00%	

[B] The tax deductions/adjustments are quantified by considering the tax attributes available for renewable energy projects. Specifically, we have considered capital cost allowances and Canadian Renewable Conservation Expenses.
[F7] Schedule 5K.
[F8] Schedule 5B.
[F9] We have calculated the additional Economic Losses related to the Economic Development Adder on the 10% capacity expansion by increasing the price (as used in Schedule 2F). The operating, capital and financing costs remain the same.
[F10] Schedule 5C.
[F11] For presentation purposes, we have ommited the visibility of certain years of the forecast.

Schedule 5E
Project North Bruce
Discounted Cash Flows - NAFTA Article 1106 (Base Case)
Amounts in CAD 000s unless otherwise stated
As at May 29, 2010

	Notes		For the year ended December 31,								
			2013	2014	2015	2016	2020	2021	2032	2033	2034
Revenue											
Price	[F1]	0.42%	[redacted]								
Production (000s MWh)	[F2]		[redacted]								
Total revenue			[redacted]								
Operating expenses	[F3]		[redacted]								
Land Payments [redacted]		2.20%	[redacted]								
Asset manager	[F4]		[redacted]								
Unplanned maintenance	[F4]		[redacted]								
Planned maintenance	[F4]		[redacted]								
Transmission charge	[F4]		[redacted]								
BOP maintenance	[F4]		[redacted]								
Property taxes	[F4]		[redacted]								
Insurance	[F4]		[redacted]								
Total operating expenses			[redacted]								
EBITDA			[redacted]								
Less Interest expense			[redacted]								
EX-IM loan interest	[F5]		[redacted]								
Term loan interest	[F5]		[redacted]								
Net cash flow after interest			[redacted]								
Less: Taxes @ 25.00%	[F6]		[redacted]								
After-tax cash flow			[redacted]								
Less Debt principal repayments			[redacted]								
EX-IM loan principal payment	[F5]		[redacted]								
Term loan principal payment	[F5]		[redacted]								
Levered free cash flows			[redacted]								
NAFTA Article 1106 - Base Case			[redacted]								
NAFTA Article 1102/1103/1105 - Base Case	[F7]		[redacted]								
Incremental levered free cash flows			[redacted]								
LOW			[redacted]								
Percent of year remaining			[redacted]								
Period			[redacted]								
Discount rate			[redacted]								
Cumulative PV factor			[redacted]								
Discounted incremental operating cash flows			[redacted]								
Incremental equity-financed capital expenditures		[F8]	[redacted]								
Net present value of incremental cash flows		[redacted]									
Gross pre-tax NPV of incremental cash flows		[redacted]									
HIGH		[redacted]									
Discount rate		[redacted]									
Cumulative PV factor		[redacted]									
Discounted incremental operating cash flows		[redacted]									
Incremental equity-financed capital expenditures		[redacted]									
Net present value of incremental cash flows		[redacted]									
Gross pre-tax NPV of incremental cash flows		[redacted]									

Notes

[F1] Power price based on FIT application.
[F2] Based on Management's best estimate.
[F3] We have tested the reasonability of total operating expenses with comparable project benchmark data. See Schedule 7 for further details. Based on our research, total operating expenses were determined to be reasonable.
[F4] We have assumed that these expenses would increase annually by 2.2%, based on inflation forecasts from Economic Intelligence Unit.
[F5] Schedule 5I.
[F6] Tax rates are based on the substantively enacted tax rates as at the Valuation Date.
Tax expense:

			2013	2014	2015	2016	2020	2021	2032	2033	2034
Net cash flows after interest	**[A]**		[redacted]								
Less: tax deductions	**[B]**		[redacted]								
Taxable income	**[A] + [B]**		[redacted]								
Tax expense		25.00%	[redacted]								

[B] The tax deductions/adjustments are quantified by considering the tax attributes available for renewable energy projects. Specifically, we have considered capital cost allowances and Canadian Renewable Conservation Expenses.
[F7] Schedule 5B.
[F8] Schedule 5L.
[F9] For presentation purposes, we have ommited the visibility of certain years of the forecast.

Schedule 5F
Project North Bruce
Discounted Cash Flows - NAFTA Article 1106 (Economic Development Adder)
Amounts in CAD 000s unless otherwise stated
As at May 29, 2010

	Notes		2013	2014	2015	2016	2020	2021	2032	2033	2034
			For the year ended December 31,								
Revenue											
Price	[F1]	0.42%			148	148	151	151	158	159	160
Production (000s MWh)	[F2]		[redacted]								
Total revenue											
Operating expenses	[F3]										
Land Payments [redacted]		2.20%									
Asset manager	[F4]										
Unplanned maintenance	[F4]										
Planned maintenance	[F4]										
Transmission charge	[F4]										
BOP maintenance	[F4]										
Property taxes	[F4]										
Insurance	[F4]										
Total operating expenses											
EBITDA											
Less: Interest expense											
EX-IM loan interest	[F5]										
Term loan interest	[F5]										
Net cash flow after interest											
Less: Taxes @ 25.00%	[F6]										
After-tax cash flow											
Less: Debt principal repayments											
EX-IM loan principal payment	[F5]										
Term loan principal payment	[F5]										
Levered free cash flows											
NAFTA Article 1106 - EDA											
NAFTA Article 1106 - Base Case	[F7]										
Incremental levered free cash flows			**-**	**-**	**1,349**	**1,349**	**1,349**	**-**	**1,011**	**1,012**	**1,007**
LOW											
Percent of year remaining			100%	100%	100%	100%	100%	100%	100%	100%	100%
Period		[redacted]									
Discount rate											
Cumula ive PV factor											
Discounted incremental operating cash flows											
Net present value of incremental cash flows											
Less: NPV NAFTA 1102/1103/1105 - EDA	[F8]										
NPV of incremental cash flows											
Gross pre-tax NPV of incremental cash flows											

HIGH

Discount rate [redacted]

Cumula ive PV factor

Discounted incremental operating cash flows

Net present value of incremental cash flows

Less: NPV NAFTA 1102/1103/1105 - EDA **[F8]**

NPV of incremental cash flows

Gross pre-tax NPV of incremental cash flows

Notes:

[F1] Power price based on FIT application. In this scenario we have added the Economic Development Adder of 0.27 cents per kWh that was offered to Samsung in the Amended GEIA. Investor's Schedule of Exhibits **C0282** (4403).

[F2] Based on Management's best estimate.

[F3] We have tested the reasonability of total operating expenses with comparable project benchmark data. See Schedule 7 for further details. Based on our research, total operating expenses were determined to be reasonable

[F4] We have assumed that these expenses would increase annually by 2.2%, based on inflation forecasts from Economic Intelligence Unit.

[F5] Schedule 5I.

[F6] Tax rates are based on the substantively enacted tax rates as at the Valuation Date.

Tax expense:

			2013	2014	2015	2016	2020	2021	2032	2033	2034
Net cash flows after interest	**[A]**		[redacted]								
Less: tax deductions	**[B]**										
Taxable income	**[A] + [B]**										
Tax expense		25.00%									

[B] The tax deductions/adjustments are quantified by considering the tax attributes available for renewable energy projects. Specifically, we have considered capital cos allowances and Canadian Renewable Conservation Expenses.

[F7] Schedule 5E.

[F8] Schedule 5C.

[F9] For presentation purposes, we have ommited the visibility of certain years of the forecast.

Schedule 5E
Project North Bruce
Discounted Cash Flows - NAFTA Article 1106 (Capacity Expansion)
Amounts in CAD 000s unless otherwise stated
As at May 29, 2010

	Notes		For the year ended December 31, 2013	2014	2015	2016	2020	2021	2032	2033	2034
Revenue											
Price	[F1]	0.42%	[redacted]								
Production (000s MWh)	[F2]										
Total revenue											
Operating expenses	[F3]										
Land Payments [redacted]		2 20%									
Asset manager	[F4]										
Unplanned maintenance	[F4]										
Planned maintenance	[F4]										
Transmission charge	[F4]										
BOP maintenance	[F4]										
Property taxes	[F4]										
Insurance	[F4]										
Total operating expenses											
EBITDA											
Less Interest expense											
EX-IM loan interest	[F5]										
Term loan interest	[F5]										
Net cash flow after interest											
Less: Taxes @ 25 00%	[F6]										
After-tax cash flow											
Less Capital expenditures											
Less Debt principal repayments											
EX-IM loan principal payment	[F5]										
Term loan principal payment	[F5]										
Levered free cash flows											
NAFTA Article 1106 - Capacity Expansion											
NAFTA Article 1106 - Base Case	[F7]										
Incremental levered free cash flows											
LOW											
Percent of year remaining											
Period											
Discount rate											
Cumulative PV factor											
Discounted incremental operating cash flows											
Incremental equity-financed capital expenditures	[F8]										
Net present value of incremental cash flows		[redacted]									
Less: NPV NAFTA 1102/1103/1105 - Capacity Expansion	[F9]										
NPV of incremental cash flows											
Gross pre-tax NPV of incremental cash flows											
Including Economic Development Adder											
NPV of EDA on capacity expansion	[F10]										
Less: NPV NAFTA 1102/1103/1105 - Capacity Expansion with EDA	[F9]										
NPV of incremental cash flows											
Gross pre-tax NPV of incremental cash flows											

Schedule 5E
Project North Bruce
Discounted Cash Flows - NAFTA Article 1106 (Capacity Expansion)
Amounts in CAD 000s unless otherwise stated
As at May 29, 2010

	Notes	For the year ended December 31, 2013	2014	2015	2016	2020	2021	2032	2033	2034
HIGH										
Discount rate		[redacted]								
Cumulative PV factor										
Discounted incremental operating cash flows										
Incremental equity-financed capital expenditures	[F8]									
Net present value of incremental cash flows										
Less: NPV NAFTA 1102/1103/1105 - Capacity Expansion	[F9]									
NPV of incremental cash flows										
Gross pre-tax NPV of incremental cash flows										
Including Economic Development Adder										
NPV of EDA on capacity expansion	[F10]									
Less: NPV NAFTA 1102/1103/1105 - Capacity Expansion with EDA	[F9]									
NPV of incremental cash flows										
Gross pre-tax NPV of incremental cash flows										

Notes

[F1] Power price based on FIT application. In this scenario we have added the Economic Development Adder of 0.27 cents per kWh that was offered to Samsung in the Amended GEIA. Investor's Schedule of
[F2] Based on Management's best estimate.
[F3] We have tested the reasonability of total operating expenses with comparable project benchmark data. See Schedule 7 for further details. Based on our research, total operating expenses were
[F4] We have assumed that these expenses would increase annually by 2.2%, based on inflation forecasts from Economic Intelligence Unit.
[F5] Schedule 5I.
[F6] Tax rates are based on the substantively enacted tax rates as at the Valuation Date.
Tax expense:

			2013	2014	2015	2016	2020	2021	2032	2033	2034
Net cash flows after interest	**[A]**		[redacted]								
Less: tax deductions	**[B]**										
Taxable income	**[A] + [B]**										
Tax expense		25 00%									

[B] The tax deductions/adjustments are quantified by considering the tax attributes available for renewable energy projects. Specifically, we have considered capital cost allowances and Canadian Renewable Conservation Expenses.
[F7] Schedule 5E.
[F8] Schedule 5M.
[F9] Schedule 5D.
[F10] We have calculated the additional Economic Losses related to the Economic Development Adder on the 10% capacity expansion by increasing the price (as used in Schedule 2F). The operating, capital and financing costs remain the same.
[F11] For presentation purposes, we have ommited the visibility of certain years of the forecast.

Schedule 5H
Project North Bruce
Financing - 1.6xle Turbines
Amounts in CAD unless otherwise stated
As at May 29, 2010

	Notes	For the year ended December 31, 2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032
EX-IM Loan Amortization	[F1]																			
Beginning balance		[redacted]																		
Less: Principal repayment																				
Ending balance																				
Interest																				
Total Principal and interest																				
Ending balance/kW																				
Term Loan Amortization	[F2]																			
Beginning balance																				
Less: Principal repayment																				
Ending balance																				
Interest																				
Total Principal and interest																				
Ending balance/kW																				

Notes

[F1] [redacted]

[F2] [redacted]

Financing for the 10% increase in capac[redacted]

EX-IM Loan Amortization	
Beginning balance	[redacted]
Less: Principal repayment	
Ending balance	
Interest	
Term Loan Amortization	
Beginning balance	
Less: Principal repayment	
Ending balance	
Interest	

Schedule 5I
Project North Bruce
Financing - 2.5XL Turbines
Amounts in CAD unless otherwise stated
As at May 29, 2010

	Notes	For the year ended December 31, 2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032
EX-IM Loan Amortization	[F1]	[redacted]																		
Beginning balance																				
Less: Principal repayment																				
Ending balance																				
Interest																				
Total Principal and interest																				
Ending balance/kW																				
Term Loan Amortization																				
Beginning balance	[F2]																			
Less: Principal repayment																				
Ending balance																				
Interest																				
Total Principal and interest																				
Ending balance/kW																				

Notes
[F1] [redacted]
[F2]

Financing for the 10% increase in capac [redacted]

EX-IM Loan Amortization	
Beginning balance	
Less: Principal repayment	
Ending balance	
Interest	
Term Loan Amortization	
Beginning balance	
Less: Principal repayment	
Ending balance	
Interest	

Schedule 5J
Project North Bruce
Development and Construction Costs - 1.6xle Turbines
Amounts in CAD 000s unless otherwise stated
As at May 29, 2010

	Notes		For the year ended December 31, 2013	2014
			Development period	Construction period
Capital costs				
Development costs	**[F1]**		[redacted]	
WTG costs				
BoP costs	**[F2]**			
Total unlevered capital costs	**[F3]**			
Financing costs				
Total development and construction costs				
LOW				
Period			3.09	4.09
PV Factor	**[F4]**	12.5%	[redacted]	
Discounted cash flows				
Sum of development and construction costs		[redacted]		
Discounted cash flows (excluding financing accounts)				
Future capital expenditures				
Capital expenditures financed by equity				
Capital expenditures financed by debt	**[F5]**			
HIGH				
Period			3.09	4.09
PV Factor	**[F4]**	11.5%	[redacted]	
Discounted cash flows				
Sum of development and construction costs		[redacted]		
Discounted cash flows (excluding financing accounts)				
Future capital expenditures				
Capital expenditures financed by equity				
Capital expenditures financed by debt	**[F5]**			

Notes:

[F1] We have tested the reasonability of total capital costs with comparable project benchmark data. See Schedule 7 for further details. Based on our research, total capital costs were determined to be reasonable.

[F2] [redacted]

[F3] BoP costs include contracted construction costs and contingency fees (of 10% of all other BoP costs) which are based on Management's best estimates based on other projects and pricing provided by Mortenson, the selected contractor for the project. The contracted construction costs for North Bruce were determined by applying he contracted construction cost ($/kWh) for Arran to North Bruce's annual energy production. Investor's Schedule of Exhibit **C0376** (001856-3.2.3).

[F4] Schedule 6.

[F5] [redacted]

Schedule 5K
Project North Bruce
Development and Construction Costs 1.6xle Turbines (Capacity Expansion)
Amounts in CAD 000s unless otherwise stated
As at May 29, 2010

	Notes		For the year ended December 31, 2013	For the year ended December 31, 2014
			Development period	Construction period
Capital costs	**[F1]**		[redacted]	
Development costs				
WTG costs	**[F2]**			
BoP costs	**[F3]**			
Total unlevered capital costs				
Financing costs				
Total development and construction costs				
LOW				
Period			3.09	4.09
PV Factor	**[F4]**	12.5%	[redacted]	
Discounted cash flows				
Sum of development and construction costs		[redacted]		
Discounted cash flows (excluding financing accounts)				
Future capital expenditures				
Capital expenditures financed by equity				
Capital expenditures financed by debt	**[F5]**			
HIGH				
Period			3.09	4.09
PV Factor	**[F4]**	11.5%	[redacted]	
Discounted cash flows				
Sum of development and construction costs		[redacted]		
Discounted cash flows (excluding financing accounts)				
Future capital expenditures				
Capital expenditures financed by equity				
Capital expenditures financed by debt	**[F5]**			

Notes:

[F1] We have tested the reasonability of total capital costs with comparable project benchmark data. See Schedule 7 for further details. Based on our research, total capital costs were determined to be reasonable.

[F2] [redacted]

[F3] BoP costs include contracted construction costs and contingency fees (of 10% of all other BoP costs) which are based on Management's best estimates based on o her projects and pricing provided by Mortenson, the selected contractor for the project. The contracted construction costs for North Bruce were determined by applying he contracted construction cost ($/kWh) for Arran to Nor h Bruce's annual energy production. Investor's Schedule of Exhibit **C0376** (001856-3.2.3).

[F4] Schedule 6.

[F5] [redacted]

Schedule 5L
Project North Bruce
Development and Construction Costs - 2.5XL Turbines
Amounts in CAD 000s unless otherwise stated
As at May 29, 2010

	Notes		For the year ended December 31, 2013	2014
			Development period	Construction period
Capital costs	**[F1]**		[redacted]	
Development costs				
WTG costs	**[F2]**			
BoP costs	**[F3]**			
Total unlevered capital costs (2.5XL turbine)				
Total unlevered capital costs (1.6xle turbine)				
Total incremental unlevered capital costs				
Financing costs				
Total financing amounts (2.5XL turbine)				
Total financing amounts (1.6xle turbine)				
Total incremental financing amounts				
Total capital costs (2.5XL turbine)				
Total capital costs (1.6xle turbine)				
Total incremental capital costs				
LOW				
Period			3.09	4.09
PV Factor	**[F4]**	12.5%	[redacted]	
Discounted cash flows				
Sum of development and construction costs		[redacted]		
Discounted cash flows (excluding financing amounts)				
Future capital expenditures				
Capital expenditures financed by equity				
Capital expenditures financed by debt	**[F5]**			
HIGH				
Period			3.09	4.09
PV Factor	**[F4]**	11.5%	[redacted]	
Discounted cash flows				
Sum of development and construction costs		[redacted]		
Discounted cash flows (excluding financing amounts)				
Future capital expenditures				
Capital expenditures financed by equity				
Capital expenditures financed by debt	**[F5]**			

Notes:

[F1] We have tested the reasonability of total capital costs wi h comparable project benchmark data. See Schedule 7 for further details. Based on our research, total capital costs were determined to be reasonable.

[F2] [redacted]

[F3] BoP costs include contracted construction costs and contingency fees (of 10% of all other BoP costs) which are based on Management's best estimates based on other projects and pricing provided by Mortenson, the selected contractor for the project. The contracted construction costs for North Bruce were determined by applying the contracted construction cost ($/kWh) for Arran to North Bruce's annual energy production. Investor's Schedule of Exhibit**C0376** (001856-3.2.3).

[F4] Schedule 6.

[F5] [redacted]

Schedule 5M
Project North Bruce
Development and Construction Costs - 2.5XL Turbines (Capacity Expansion)
Amounts in CAD 000s unless otherwise stated
As at May 29, 2010

	Notes		For the year ended December 31, 2013	2014
			Development period	Construc ion period
Capital costs	**[F1]**		[redacted]	
Development costs				
WTG costs	**[F2]**			
BoP costs	**[F3]**			
Total unlevered capital costs (2.5XL turbines - capacity expansion)				
Total unlevered capital costs (2.5XL turbines)				
Total incremental unlevered capital costs				
Financing costs				
Total unlevered capital costs (2.5XL turbines - capacity expansion)				
Total financing amounts (2.5XL turbines)				
Total incremental financing amounts				
Total capital costs (2.5XL turbines - capacity expansion)				
Total capital costs (2.5XL turbines)				
Total incremental capital costs				
LOW				
Period			3.09	4.09
PV Factor	**[F4]**	12.5%	[redacted]	
Discounted cash flows				
Sum of development and construction costs		[redacted]		
Discounted cash flows (excluding financing amounts)				
Future capital expenditures				
Capital expenditures financed by equity				
Capital expenditures financed by debt	**[F5]**			
HIGH				
Period			3.09	4.09
PV Factor	**[F4]**	11.5%	[redacted]	
Discounted cash flows				
Sum of development and construction costs		[redacted]		
Discounted cash flows (excluding financing amounts)				
Future capital expenditures				
Capital expenditures financed by equity				
Capital expenditures financed by debt	**[F5]**			

Notes:

[F1] We have tested the reasonability of total capital costs wi h comparable project benchmark data. See Schedule 7 for further details. Based on our research, total capital costs were determined to be reasonable.

[F2] [redacted]

[F3] BoP costs include contracted construction costs and contingency fees (of 10% of all other BoP costs) which are based on Management's best estimates based on other projects and pricing provided by Mortenson, the selected contractor for the project. The contracted construction costs for North Bruce were determined by applying the contracted construction cost ($/kWh) for Arran to North Bruce's annual energy production. Investor's Schedule of Exhibit**C0376** (001856-3.2.3).

[F4] Schedule 6.

[F5] [redacted]

Schedule 6A
Weighted average cost of capital
Amounts in USD unless otherwise stated
As at January 21, 2010

Ticker	Guideline Companies:	Total Book Value of Debt (1)	Total Book Value of Preferred (1)	Total Market Value of Equity (2)	Total Market Value of Capital	Debt to Capital	Equity to Capital	Historical Effective Tax Rate	Levered Equity Beta (3)	Historical Debt to Capital (4)	Unlevered Equity Beta
TSX:INE	Innergex Renewable Energy Inc.	$ 224	$ -	$ -	$ 224	100.0%	0.0%	27.5%	0.72	100%	N/A
XTRA:PNE3	PNE Wind AG	$ 101	$ -	$ 132	$ 233	43.4%	56.6%	3.5%	0.83	47%	0.44
DB: EKT	Energiekontor AG	$ 166	$ -	$ 75	$ 240	69.0%	31.0%	49.0%	0.80	71%	0 35
OM: ARISE	Arise AB (publ)	$ 84	$ -	$ -	$ 84	100.0%	0.0%	0.0%	N/A	N/A	N/A
ENXTPA: TEO	THEOLIA S.A.	$ 703	$ -	$ 188	$ 891	78.9%	21.1%	0.0%	0.54	55%	0.24
ASX: IFN	Infigen Energy	$ 1,371	$ -	$ 1,006	$ 2,377	57.7%	42.3%	86.1%	0.97	56%	0.82
					Average	**74.8%**	**25.2%**	**27.7%**	**0.77**	**66.0%**	**0.46**
					Median	**73.9%**	**26.1%**	**15.5%**	**0.80**	**56.3%**	**0.40**
					Selected						**0.42**

	Low	High	
Unlevered Equity Beta	0.40	0.44	Unlevered Equity Beta = Levered Equity Beta / [1 + (1 - Tax Rate) x Debt-to-Equity]
Debt-to-Equity	400.0%	400.0%	
Selected Subject Tax Rate	25.0%	25.0%	As provided by Management
Relevered Equity Beta	**1.60**	**1.76**	Levered Equity Beta = Unlevered Equity Beta x [1 + (1 - Tax Rate) x Debt-to-Equity]
Risk Free Rate	4.38%	4.38%	20 year U.S. Treasury Constant Maturity Yields as of the Valuation Date. Source: U.S. Federal Reserve
Equity Risk Premium	5.75%	5.75%	Source: Deloitte Financial Advisory research. Adjusted Ibbotson ERP for Volatility and P/E to reflect 85
Levered Equity Beta	1.60	1.76	year trailing market fluctuations.
Cost of Equity Capital	**13.56%**	**14.52%**	Cost of Equity Capital = Risk Free Rate + [Equity Beta x Equity Risk Premium].
Unsystematic Risk Factors:			
Size Premium	1.85%	1.85%	Source: 2010 Ibbotson & Associates Risk Premium Report.
Company-Specific Risk	-3 00%	-3.00%	Risk premium based on qualitative factors hat reflect company specific risks.
Country Adjustment Factor	-0.78%	-0.83%	Source: 2010 Ibbotson & Associates International Cost of Capital Report
Subject's Cost of Equity Capital	**11.63%**	**12.55%**	
Cost of Equity (Rounded)	**11.50%**	**12.50%**	
Subject's Estimated Pre-Tax Cost of Debt Capital	5.38%	5.38%	As estimated by Management.
Tax Rate	25 00%	25.00%	Based on the long term expected tax rates.
After-Tax Cost of Debt	**4.04%**	**4.04%**	
Debt-to-Capital	80.0%	80.0%	
Equity-to-Capital	20.0%	20.0%	
Weighted Average Cost of Capital	5.55%	5.74%	WACC = [(Debt-to-Capital x Cost of Debt x (1 - Tax Rate)] + [Equity-to-Capital X Cost of Equity Capital]
Weighted Average Cost of Capital (Rounded)	**5.50%**	**5.75%**	

Notes:
(1) Book value of debt used as an approximation of market value. For purposes of calculating capital structure preferred equity, if any, was added to equity at book value.
(2) Represents current stock price imes common shares outstanding.
(3) Bloomberg beta based on 5-Year historical Weekly data per Capital IQ.
(4) Based on 5-Year Avg. debt to market value of invested capital as at Valuation Date.

Source: Capital IQ.

Schedule 6B
Weighted average cost of capital
Amounts in USD unless otherwise stated
As at May 29, 2010

Ticker	Guideline Companies:	Total Book Value of Debt (1)	Total Book Value of Preferred (1)	Total Market Value of Equity (2)	Total Market Value of Capital	Debt to Capital	Equity to Capital	Historical Effective Tax Rate	Levered Equity Beta (3)	Historical Debt to Capital (4)	Unlevered Equity Beta
TSX:INE	Innergex Renewable Energy Inc.	$ 471	$ -	$ 504	$ 974	48.3%	51.7%	27.5%	0.75	90%	0.10
XTRA:PNE3	PNE Wind AG	$ 92	$ -	$ 115	$ 207	44.3%	55.7%	3.2%	0 95	45%	0.53
DB: EKT	Energiekontor AG	$ 176	$ -	$ 57	$ 233	75.6%	24.4%	63.7%	0.76	66%	0.45
OM: ARISE	Arise AB (publ)	$ 81	$ -	$ 202	$ 283	28.7%	71.3%	0.0%	1 09	N/A	N/A
ENXTPA: TEO	THEOLIA S.A.	$ 609	$ -	$ 122	$ 731	83.4%	16.6%	0.0%	0 54	50%	0.27
ASX: IFN	Infigen Energy	$ 1,451	$ -	$ 561	$ 2,012	72.1%	27.9%	52.4%	0 98	60%	0.58
					Average	**58.7%**	**41.3%**	**24.5%**	**0.85**	**62.0%**	**0.39**
					Median	**60.2%**	**39.8%**	**15.3%**	**0.86**	**59.7%**	**0.45**
					Selected						**0.42**

	Low	High	
Unlevered Equity Beta	0.40	0.44	Unlevered Equity Beta = Levered Equity Beta / [1 + (1 - Tax Rate) x Debt-to-Equity]
Debt-to-Equity	400.0%	400.0%	
Selected Subject Tax Rate	25.0%	25.0%	As provided by Management
Relevered Equity Beta	**1.60**	**1.76**	Levered Equity Beta = Unlevered Equity Beta x [1 + (1 - Tax Rate) x Debt-to-Equity]
Risk Free Rate	4.05%	4.05%	20 year U.S. Treasury Constant Maturity Yields as of the Valuation Date. Source: U.S. Federal Reserve
Equity Risk Premium	5.75%	5.75%	Source: Deloitte Financial Advisory research. Adjusted Ibbotson ERP for Volatility and P/E to reflect 85
Levered Equity Beta	1.60	1.76	year trailing market fluctuations.
Cost of Equity Capital	**13.23%**	**14.19%**	Cost of Equity Capital = Risk Free Rate + [Equity Beta x Equity Risk Premium].
Unsystematic Risk Factors:			
Size Premium	1.85%	1.85%	Source: 2010 Ibbotson & Associates Risk Premium Report.
Company-Specific Risk	-2.75%	-2.75%	Risk premium based on qualitative factors that reflect company specific risks.
Country Adjustment Factor	-0.76%	-0.81%	Source: 2010 Ibbotson & Associates International Cost of Capital Report
Subject's Cost of Equity Capital	**11.57%**	**12.48%**	
Cost of Equity (Rounded)	**11.50%**	**12.50%**	
Subject's Estimated Pre-Tax Cost of Debt Capital	5.38%	5.38%	As estimated by Management.
Tax Rate	25.00%	25.00%	Based on the long term expected tax rates.
After-Tax Cost of Debt	**4.04%**	**4.04%**	
Debt-to-Capital	80.0%	80.0%	
Equity-to-Capital	20.0%	20.0%	
Weighted Average Cost of Capital	5.54%	5.72%	WACC = [(Debt-to-Capital x Cost of Debt x (1 - Tax Rate)] + [Equity-to-Capital X Cost of Equity Capital]
Weighted Average Cost of Capital (Rounded)	**5.50%**	**5.75%**	

Notes:
(1) Book value of debt used as an approximation of market value. For purposes of calculating capital structure preferred equity, if any, was added to equity at book value.
(2) Represents current stock price imes common shares outstanding.
(3) Bloomberg beta based on 5-Year historical Weekly data per Capital IQ.
(4) Based on 5-Year Avg. debt to market value of invested capital as at Valuation Date.

Source: Capital IQ.

Schedule 7
Comparable project analysis
USD millions

				Capital costs							
	Development stage	1.6xle Project capacity (MW)	2.5XL Project capacity (MW)	Total capital costs 1.6xle	Cost per MW 1.6xle	Total capital costs 2.5XL	Cost per MW 2.5XL	Industry reports			
								Low	Average	Median	High
TTD	Late stage	[redacted]						1.75	2.03	2.05	2.22
Arran	Late stage	[redacted]						1.75	2.03	2.05	2.22
Summerhill	Late stage	[redacted]						1.75	2.03	2.05	2.22
North Bruce	Late stage	[redacted]						1.75	2.03	2.05	2.22

				Operating costs					
	Development stage	1.6xle Project capacity (MW)	2.5XL Project capacity (MW)	Costs ($/MWh) 1.6xle	Costs ($/MWh) 2.5XL	Industry reports			
						Low	Average	Median	High
TTD	Late stage	[redacted]				9.00	14.89	15.00	24.00
Arran	Late stage	[redacted]				9.00	14.89	15.00	24.00
Summerhill	Late stage	[redacted]				9.00	14.89	15.00	24.00
North Bruce	Late stage	[redacted]				9.00	14.89	15.00	24.00

Schedule 8
Precedent transactions
Amounts in CAD unless otherwise stated

Wind farm details					Transaction details				
Project	**Developer**	**Country**	**Project capacity (MW)**	**Number of turbines**	**Date**	**FX rate (per Bank of Canada)**	**Transaction price (€M)**	**Implied late-stage price multiple (CAD millions per MW)**	**Project stage of completion at date of transaction**
Midwest Renewable	MREC Partners & Midwest Renewable Energy Projects	USA	120MW in early stage 400MW in late-stage	N/A	16-Oct-06	1.4251	30	0.11x	Early & Late-stage
Project Wildmare, Bullmoose, Tumbler Ridge, and Meikle	Finavera Wind Energy	Canada	300MW in late-stage	N/A	20-Dec-12	1.2847	31	0.13x	Late-stage
Dokie Wind	Earth First Canada	Canada	156MW in late-stage	48	11-Dec-09	1.5454	147	0.32x	Late-stage
EverPower Wind Holding	EverPower	USA	821 in late-stage	N/A	26-Aug-09	1.5639	246	0.30x	Late-stage
Butter Creek **[F1]**	Ralls Corp. (Sany Group)	USA	40 MW in late stage	20	15-May-12	1.2804	30	0.96x	Late-stage
Minimum								**0.11x**	
Median								**0.30x**	
Average								**0.36x**	
Adjusted average								**0.15x**	
Maximum								**0.96x**	
Implied multiples						DCF Value (CAD millions)			
Project TTD	Mesa Power Group	Canada	[redacted]		21-Jan-10	[redacted]			
Project Arran	Mesa Power Group	Canada	[redacted]		21-Jan-10	[redacted]			
Project Summerhill	Mesa Power Group	Canada	[redacted]		29-May-10	[redacted]			
Project North Bruce	Mesa Power Group	Canada	[redacted]		29-May-10	[redacted]			

Notes:
[F1] The Butter Creek transaction did not close for national security reasons.

Appendix A – Scope of review

We have reviewed and relied upon the following documents for the preparation of this report.

No.	Ref.	Title of document
	n/a	Notice of Intent to Submit a Claim to Arbitration, Mesa Power Group, LLC v. Government of Canada, dated July 6, 2011.
	n/a	Notice of Arbitration under the rules of the United Nations Commission on International Trade Law and NAFTA, dated October 4, 2011.
	C0358	Mortenson – Twenty-two Degrees – 150 MW – GE 2.5XL, 100 Rotor, 100M HH – Open Book Summary, dated July 21, 2010.
	C0359	Golder Associates, Technical Memorandum, dated July 12, 2011.
	C0129	Arran – FIT Application to the OPA, dated November 25, 2009.
	C0360	North Bruce I – FIT Application to the OPA, dated May 29, 2010.
	C0361	North Bruce II – FIT Application to the OPA, dated May 29, 2010.
	C0362	Summerhill I – FIT Application to the OPA, dated May 29, 2010.
	C0363	Summerhill II – FIT Application to the OPA, dated May 29, 2010.
	C0364	TTD – FIT Application to the OPA, dated November 25, 2009.
	C0365	Arran – FIT Application to the OPA, dated November 25, 2009 (no land option documents attached).
	C0366	North Bruce I – FIT Application to the OPA, dated May 29, 2010 (no land option documents attached).
	C0367	North Bruce II – FIT Application to the OPA, dated May 29, 2010 (no land option documents attached).
	C0368	Summerhill I – FIT Application to the OPA, dated May 29, 2010 (no land option documents attached).

C0369	Summerhill II – FIT Application to the OPA, dated May 29, 2010 (no land option documents attached).
C0370	Leader Resources Services Corp. – Arran, dated June 21, 2011.
C0371	Leader Resources Services Corp. - North Bruce Wind Energy Project - Development Status, dated July 20, 2011.
C0372	Leader Resources Services Corp. - Summerhill Wind Energy Project - Development Status, dated July 20, 2011.
C0373	Leader Resources Services Corp. – TTD, dated June 21, 2011.
C0021	Summary document, Renewal Energy Approval Process, undated.
C0374	Assessment of the Energy Production of the Proposed Arran Wind Energy Project prepared by Garrad Hassan Canada Inc. dated June 25, 2010.
C0375	Mortenson – Arran – 112 MW – GE 1.6xle, 85.5 Rotor, 80M HH – Open Book Summary, dated March 26, 2010.
C0376	Mortenson – TTD – 144 MW – GE 1.6xle, 85.5 Rotor, 80M HH – Open Book Summary, dated March 26, 2010.
C0377	Letter from Export-Import Bank of the United States to GE Capital Markets Corporate, dated September 23, 2010.
C0378	GL Garrad Hassan – Assessment of the Energy Production of the Proposed Twenty-Two Degree Wind Energy Project, dated November 9, 2010.
C0379	Amended and restated master turbine sale agreement for the sale of power generation equipment and related services with GE, dated [redacted]
C0380	External Change Order (ECO) Proposal No. 3 between Mesa Power Pampa, LLC and GE, dated [redacted]
C0037	Second amended and restated master turbine sale agreement for the sale of power generation equipment and related services, dated [redacted]
C0381	External Change Order (ECO) Proposal No. 3 between Mesa Power Pampa, LLC and GE, dated [redacted]
C0382	Termination Letter from Mesa Power to GE, dated [redacted]

C0383	Termination Letter from Mesa Power to GE, dated [redacted].
C0384	Leader Services Corp. - TTD Wind Energy Project Schedule, dated December 5, 2010.
C0385	Leader Services Corp. - TTD Wind Energy Project Schedule, dated December 5, 2010.
C0386	Leader Services Corp. - Arran Wind Energy Project Schedule, dated December 5, 2010.
C0387	Leader Services Corp. - Arran Wind Energy Project Schedule, dated December 5, 2010.
C0107	E-mail from Michael Volpe from GE to Cole Robertson from Mesa Power, dated August 5, 2010.
C0388	Arran Project ULC General Ledger 2009.
C0389	North Bruce Project ULC General Ledger 2009.
C0390	Summerhill Project ULC General Ledger 2009.
C0391	TTD Project ULC General Ledger 2009.
C0206	Mortenson – Ontario Wind Project with Domestic Content Requirements – 100 MW – GE 2.5XL, 100 Rotor, 85-100M HH – Project Cost Summary, dated November 12, 2013.
C0027	Project Arran - Financial Model, dated November 3, 2011.
C0028	Project North Bruce - Financial Model, dated November 3, 2011.
C0030	Project Summerhill - Financial Model, dated November 3, 2011.
C0031	Project TTD - Financial Model – 20111003, dated November 3, 2011.
C0282	GEIA Amending Agreement, dated July 29, 2011.
C0322	GEIA Agreement, dated January 21, 2010.
C0203	CanWEA, The Secret is Out, Wind is in, undated.
C0204	CanWEA, Wind Facts, dated January 2013.
C0223	EIU Country forecast – Canada, dated July 2011.
C0230	The Guardian, Wind Power Capacity Grew by 20% Globally in 2012, dated February 12, 2013.
C0238	KPMG, Wind Energy in Canada: Realizing the Opportunity, dated July 2013.
C0246	MarketLine Industry Profile, Global Wind Energy, dated May 2013.

C0251	MarketLine Industry Profile, Renewable Energy in Canada, dated June 2013.
C0253	MarketLine Industry Profile, Renewable Energy in North America, dated June 2013.
C0261	MarketLine Industry Profile, Renewable Energy in the United States, dated June 2013.
C0279	The Conference Board of Canada, Provincial Outlook, Summer 2011.
C0340	Ontario Power Authority Feed-In Tariff Program, FIT Rules Version 1.5, dated June 3, 2011.
C0341	Ontario Power Association, FIT Rules Version 3.0- Draft, dated September 4, 2013, http://fit.powerauthority.on.ca/sites/default/files/page/FIT%20Rules%20DRAFT%20Version%203.pdf
C0342	Ontario Power Association, FIT 3.0 Final Program Documents, dated October 9, 2013, http://fit.powerauthority.on.ca/newsroom/october-9-2013-FIT-3-final-documents.
C0343	Ontario Power Association, Development of a New Large Renewable Procurement Process, dated August 30, 2013.
C0344	Final FIT 2.0 Program Documents, dated August 10, 2012.
C0345	Ontario Power Authority, FIT Program Newsroom, Ontarians get the green light for 700 rooftop solar projects, dated December 16, 2009.
C0346	Draft FIT 3 Program Documents, dated September 4, 2013.
C0347	FIT Contract Version 1.5.1 dated July 15, 2011, Indexation (Exhibit B, Article 1.3). http://fit.powerauthority.on.ca/sites/default/files/FIT%20Rules%20Version%201%205%201_Program%20Review_0.pdf
C0348	Economic Intelligence Unit Canada Country Report, dated September 2013.
C0349	Standard FIT Contract definitions, dated July 15, 2011.
C0350	FIT website: http://www.fit.powerauthority.on.ca/Storage/102/11184_Launch_Project_Information_-_Dec_21_2010.pdf
C0351	Feed-In Tariff (FIT) Program, Program Overview, http://fit.powerauthority.on.ca/sites/default/files/page/FIT_Program_Overview_Version_2.pdf
C0352	Letter to Mr. Colin Andersen RE: Administrative Matters Related to Renewable Energy and Conservation Programs, dated August 16, 2013, http://powerauthority.on.ca/sites/default/files/page/DirectionAdministrativeMatters-renewables-Aug16-2013.pdf

C0353	Proposed Feed-in Tariff Price Schedule, Stakeholder Engagement – Session 4, April 7, 2009, http://fit.powerauthority.on.ca/Storage/10147_FIT_Stakeholder_Engagement_-_Session_4_FIT_Price_Schedule_FINAL_(HP).pdf.
C0354	Ontario's Feed-in Tariff Program, Two-Year Review Report, March 2012, http://www.energy.gov.on.ca/docs/en/FIT-Review-Report.pdf
C0355	Ontario Power Authority, Pricing Schedule, August 2010. http://fit.powerauthority.on.ca/Storage/11122_FIT_Price_Schedule_August_13_2010.pdf
C0356	Ontario Power Authority Pricing Schedule, dated April 2012, http://fit.powerauthority.on.ca/sites/default/files/news/2013-FIT-Price-Comparison-Table.pdf
C0357	2013 FIT Price Review Stakeholder Feedback, March 2013, ,http://www.biogasassociation.ca/bioExp/images/uploads/documents/2013/other/2013_Price_Review_Stakeholder_Feedback_Questionnaire.pdf
C0075	Letter from Mesa Power Group to Deloitte LLP, dated November 15, 2013.

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Appendix B - Restrictions, major assumptions, qualifications, and limitations

This Report is not intended for circulation or publication, nor is it to be reproduced for any purpose other than as described herein, without our prior express written permission in each specific instance. We do not assume any responsibility for losses incurred by any party as a result of circulation, publication, or reproduction of this Report contrary to the provisions of this paragraph.

This Report must be considered as a whole and selecting portions of the Report or the factors noted by us, without considering all factors and analyses together could create a misleading view of the process underlying this Report. The preparation of this Report was a complex process and considers various scenarios and is not necessarily susceptible to partial analysis or summary description. Any attempt to do so could lead to undue emphasis on any particular factor, calculation, or analysis.

This Report has been based on information, documents and explanations that have been provided to us and therefore the validity of our conclusions rely on the integrity of such information. Our scope of review is listed in Appendix A. We were not under any obligation or agreement to investigate the accuracy of any third-party information, nor have we performed any investigative procedures to independently verify the accuracy of any third-party information.

Should any of the information provided to us not be factual or correct, or should we be asked to consider different information or assumptions, our conclusions as set out in this Report could be significantly different.

We reserve the right, but will be under no obligation, to review this Report, and if we consider it necessary, to revise this Report in light of any information which becomes known to us after the date of this Report.

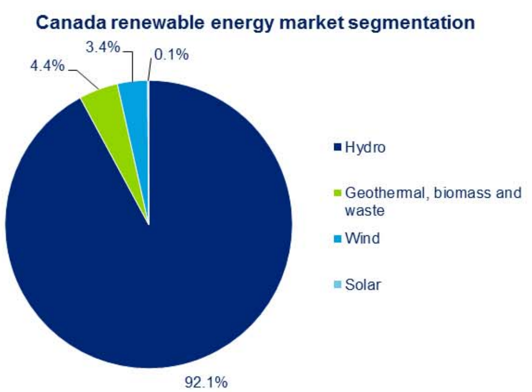
In preparing this Report, we have made certain assumptions as described in this section and throughout this Report. Should any of these assumptions prove inappropriate, our calculations and analyses, as expressed in this Report could change, perhaps materially. We caution the reader in this regard.

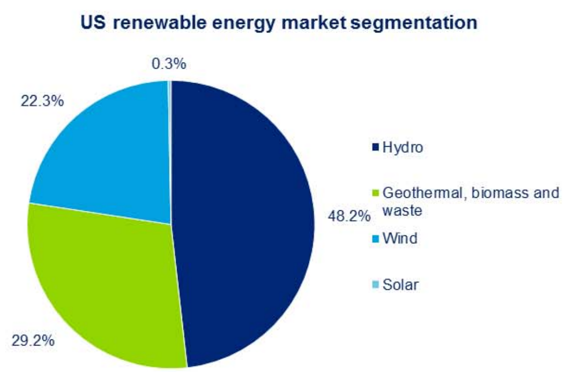
Appendix C – Industry and economic overview

Industry overview - Renewable Energy

North America[102]

C.1 The renewable energy market includes electricity generated by geothermal, biomass and waste, solar, wind and hydroelectric methods. The North American renewable energy market has shown strong growth with a market value compound annual growth rate ("CAGR") of 8.4% from 2008 to 2012. Market value growth is expected to decline over the forecast with a CAGR of 6.5% from 2012 to 2017. Historical annual market value growth rates increased significantly in 2011 reaching 17.3% and then dropped to 4.4% in 2012. The United States accounts for 64% of the total North American renewable energy market value, with Canada and Mexico contributing 31% and 5%, respectively. The following charts illustrate the market segmentation in the Canada and US renewable energy markets.





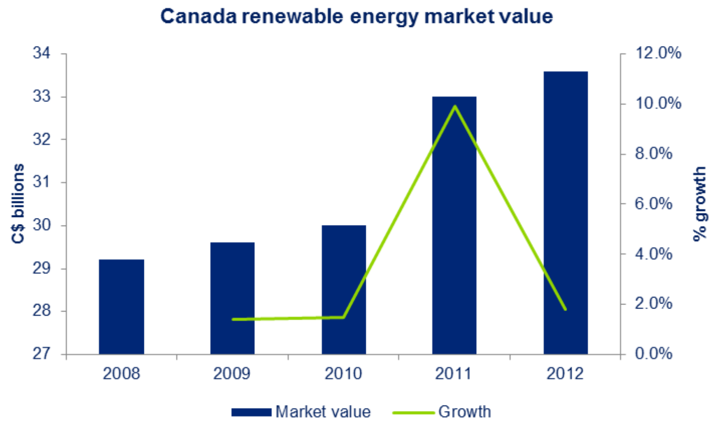
Canada: MarketLine Industry Profile, Renewable Energy in Canada[103]; US: MarketLine Industry Profile, Renewable Energy in the United States.[104]

Canada[105]

C.2 The Canadian renewable energy market experienced a CAGR in value of 3.6% from 2008 to 2012 and anticipates a 2.8% CAGR from 2012 to 2017 which is lower than the expected overall North American growth. According to historical results, in 2011, growth increased to approximately 10% before slowing to

[102] Investor's Schedule of Exhibits **C0253** (004388) MarketLine Industry Profile, Renewable Energy in North America, June 2013.
[103] Investor's Schedule of Exhibits **C0251** (004387) MarketLine Industry Profile, Renewable Energy in Canada, June 2013.
[104] Investor's Schedule of Exhibits **C0261** (004389) MarketLine Industry Profile, Renewable Energy in the United States, June 2013.
[105] Investor's Schedule of Exhibits **C0251** (004387) MarketLine Industry Profile, Renewable Energy in Canada, June 2013.

approximately 2% in 2012. The following chart shows historical market value growth:



Canada: MarketLine Industry Profile, Renewable Energy in Canada.[106]

C.3 The majority of the market, approximately 92%, is focused on hydroelectric means of electricity generation. Although hydroelectric means makes up the majority of the renewable energy market, wind power is growing quickly. Further, there is interest from politicians to increase the percentage of Canada's total electricity generated by renewable energy methods.

C.4 Please refer to Section 2 of the report for a description of the OPA's FIT program.

Wind energy

Global[107]

C.5 Wind energy accounts for 2% of overall global electricity and is the global leading renewable technology due to its rapid development. The global wind energy market revenue has a compound annual growth rate of 23.8% from 2008 to 2012 and an industry volume (megawatts) compound annual growth rate of 24.2% for the same historical period. Both revenue and volume growth are forecast to decelerate over the forecast period from 2012 to 2017 with an estimated compound annual growth rate of 15.2% and 14.1% for revenue and volume, respectively. Asia-Pacific, Europe and the Americas make up 24.6%, 51.7% and 23.6% of the global wind energy industry, respectively in 2012. Middle East and Africa only make up 0.1% of the total industry.

C.6 China is the global leader in wind power with 77 gigawatts installed, followed by the US with 60 gigawatts. The UK is the leader in offshore wind deployment followed by Denmark and Belgium.[108]

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[106] Investor's Schedule of Exhibits **C0251** (004387) MarketLine Industry Profile, Renewable Energy in Canada, June 2013.
[107] Investor's Schedule of Exhibits **C0246** (004386) MarketLine Industry Profile, Global Wind Energy, May 2013.
[108] Investor's Schedule of Exhibits **C0230** (004384) The Guardian, Wind Power Capacity Grew by 20% Globally in 2012, February 12, 2013.

Canada

C.7 Canada is the ninth largest wind producer in the world and wind power represents 3% of total Canadian electricity demand. Wind power is forecast to supply 20% of Canadian electricity demand by 2025 with benefits including 52,000 jobs and a reduction of 17 megatonnes of greenhouse gas emission. Wind power grew 20% in 2012 and is expected to continue expanding in 2013 based on projects contracted across Canada. Total volume (megawatts) is expected to increase by 86% from 6,500 MW in 2012 to 12,000 MW in 2016 representing a compound annual growth rate of approximately 17%.[109] As of March 2013, there were 164 wind farms with a total of 3,762 turbines producing enough electricity to power over 2 million Canadian homes.[110]

C.8 Canadian wind projects contracted over the past five years that are seeking financing in order to start construction will result in increased competition for financing. Public bonds are an alternative financing option for wind energy projects normally used to raise amounts over $150 million. This structure was used for the first time to finance a Canadian wind farm by Brookfield Renewable Energy Partners in February 2013 for an amount of $450 million at an interest rate of 5.13% for term of 18 years.[111]

C.9 Canada's leading wind energy market is Ontario with 2,043 MW of installed capacity in as of May 2013, followed by Quebec and then Alberta. Ontario grid capacity constraints and the uncertainty regarding the new competitive wind procurement process will result in a wind procurement slowdown over the next three years. Other provinces including Alberta, British Columbia and Quebec are expected to have wind investment opportunities going forward. [112]

Economic overview

Canada

C.10 The following is a review of the economic outlook for Canada, the geographic region in which Mesa Power's projects were planned to operate. This summary is based on our review of the Economist Intelligence Unit ("EIU") Country Forecast publications as at July 2011. The following contains excerpts and summaries of views expressed by the economists in this publication.

C.11 GDP is expected to grow by 2.6% in 2011 due to continued investment in the mining sector. The US economy growth is also expected to positively impact GDP growth for Canada as the US takes in approximately three quarters of Canada's exports. A slowdown in the US economy is a significant risk to the forecast. GDP growth is expected to remain relatively stable over the forecast period averaging 2.5% from 2011 to 2015.

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109 Investor's Schedule of Exhibits **C0204** (004382) CanWEA, Wind Facts, January 2013.
110 Investor's Schedule of Exhibits **C0203** (004381) CanWEA, The Secret is Out, Wind is in.
111 Investor's Schedule of Exhibits **C0238** (004385) KPMG, Wind Energy in Canada: Realizing the Opportunity, July 2013.
112 Investor's Schedule of Exhibits **C0238** (004385) KPMG, Wind Energy in Canada: Realizing the Opportunity, July 2013.

C.12 Consumer price inflation is expected to average 2.9% in 2011 which is above the Bank of Canada's target rate of 2.0%. Inflation reached 3.5% in May 2011 mainly due to increasing commodity prices and changes in sales tax regimes. Inflation is forecast to decrease over the forecast and stabilize at a rate of 2.3% in 2014 and 2015.

C.13 In July 2011, the exchange rate was strong at C$0.97:US$1.00 and is expected to weaken slightly to an average of C$0.98:US$1.00 in 2011. The rise in oil prices in February and March of 2011 strengthened the Canadian dollar as Canada is an energy exporter but global oil prices are expected to fall in the second half of 2011, decreasing the value of the dollar. The currency has also stayed strong since mid-2010 due to the Bank of Canada's monetary tightening compared to less-stringent monetary conditions in the US. The exchange rate is expected to average C$0.99:US$1.00 from 2011 to 2015.

C.14 Canada's first current-account deficit in 11 years occurred in 2009. The EIU expects the deficit to decrease to 2.7% of GDP in 2011 compared to 3.1% of GDP in 2010. A decrease in oil prices is expected to result in an increase in the current-account deficit in 2012 before continuing to decrease over the forecast.

C.15 The table below provides a summary of key economic indicators for Canada from 2010 to 2015:

Key Economic Indicators	2010[a]	2011[b]	2012[b]	2013[b]	2014[b]	2015[b]
Real GDP growth (%)	3.2	2.6	2.4	2.5	2.5	2.6
Consumer price inflation (av; %)	1.8	2.9	2.0	2.2	2.3	2.3
3-month prime corporate paper rate (av; %)	0.8	1.5	2.6	3.6	5.3	6.0
Unemployment rate (%)	8.0	7.4	7.1	6.8	6.4	5.9
Exchange rate (av; C$:US$)	1.03	0.98	1.01	1.00	0.98	0.97

a Economist Intelligence Actual.
b Economist Intelligence Unit Forecasts.

Ontario

C.16 The following is a review of the economic outlook for Ontario, the geographic region in Canada in which Mesa Power's projects planned to operate. This summary is based on our review of the Conference Board of Canada Provincial Outlook, Summer 2011. The following contains excerpts and summaries of views expressed by the economists in this publication.

C.17 Economic growth is expected to slow due to the Japanese earth quake and global supply-chain disruptions, including the easing of fiscal stimulus related spending. Ontario was impacted by the earth quake, specifically in the automotive industry as production for Honda and Toyota dropped by 37.0% in the second quarter. Recovery is expected to be fast resulting in strong manufacturing growth of 4.9% in 2012. GDP is expected to grow by 2.2% in 2011 due to growth in the US and government incentives to increase business in

Ontario. GDP growth is expected to increase to 2.5% in 2012 based on recovery in the manufacturing sector.

C.18 Consumer spending increased due to the Ontario government's three payments to ease the transition to harmonized sales tax (HST). Labour markets are also improving as the unemployment rate is expected to decline to a rate of 6.9% in 2012. Industrial average wages and salaries are expected to increase by 3.6% in 2011 and 3.0% in 2012 due to tighter labour markets.

C.19 Ontario is expected to have a trade deficit for the next five years due to the strong Canadian dollar promoting imports and slowing exports. Exports are expected to grow by 4.5% in 2011 and 6.4% in 2012, both below the 11.3% growth in 2010.

C.20 Investment in Ontario has a positive outlook as business investment is expected to grow by 9.0% in 2011 and 4.3% in 2012. Ontario introduced a long term energy plan including more renewable-power generating plants that has resulted in Samsung investing $7 billion (over the life of the project) in Ontario wind and solar power projects. Increased spending in exploration due to high commodity prices has resulted in increased investment in Northern Ontario and potential development opportunities include mines and infrastructure products.

C.21 The table below provides a summary of key economic indicators for Ontario from 2010 to 2015:

Key Economic Indicators	2010[a]	2011[b]	2012[b]
Real GDP growth (%)	3.0	2.2	2.5
Consumer price index (%)	2.4	3.3	2.3
Unemployment rate (%)	8.6	7.7	6.9
Personal disposable income	5.9	4.1	3.9

a Conference Board of Canada Actual.
b Conference Board of Canada Forecasts.

Appendix D – Curriculum vitae

Richard Taylor, CA, CBV

Richard Taylor, Partner, Valuations Toronto Office
Deloitte LLP
Tel: 416-775-7499 Email: rictaylor@deloitte.ca

Profile
Richard Taylor is a Partner in our Financial Advisory group and serves as the Lead Valuations Partner.

He has been involved in business valuation, financial litigation and related matters since 1985, acting on behalf of shareholders in connection with companies engaged in diverse industries in Canada and the United States. He has direct industry experience as the Vice President, Finance of a commercial real estate development and consulting firm. Richard continues to lecture across Canada on the topic of business valuation and is a past member of the Board of Directors of the Canadian Institute of Chartered Business Valuators.

Richard also has experience in litigation advisory services and has given testimony in federal and provincial courts and before arbitration panels.

Experience
Energy / power: Engaged to determine fair market value for a number of LDCs for transaction, taxation and fair value reporting purposes. Valuation of renewable energy projects for taxation, fair value reporting and international arbitration purposes.

Real Estate: Direct experience as the Vice President Finance for a real estate development company. Provided valuation and fairness opinions for a number of public and private real estate development, real estate services and real estate holding companies.

Mining: Engaged to conduct fairness opinion familiarization exercises in respect of a US$150 billion proposed takeover of a global mining company. Our assignment involved extensive valuation analysis of the company's operations including major global businesses in Iron Ore, Copper, Aluminum, Coal, Uranium, Diamonds and Industrial Minerals. Engaged to prepare a damages report regarding the expropriation of a mining property for international arbitration purposes.

Primary resource / mining: Valuation of a major mining and primary metals company for transaction purposes. Determination and review of fair value determinations of mining companies and mining assets for financial statement purposes.

Private Equity: Valuation experience related to private equity investments in a number of private equity and labour sponsored investment funds. Experience in the determination of the fair market value of the shares of venture capital and private equity portfolio companies.

Financial Instrument: Valuation of numerous financial instruments for transaction, tax and financial reporting purposes.

Manufacturing/Processing: Valuation of numerous manufacturing and processing entities for transaction, tax, financial reporting and regulatory purposes (Rule 61-501).

Transportation: Valuation of transportation companies (trucking, airlines, logistics) for transaction, tax and arbitration purposes.

Primary resource / forestry: Valuation of timberlands for tax and arbitration purposes and forest services companies for corporate and transaction purposes.

Asset management: Valuation of numerous financial and real estate asset management companies for transaction, tax and regulatory purposes (Rule 61-501)

Retail: Provided valuations of brand names, trademarks, other intangible assets and lease interests for tax and financial reporting purposes.

International arbitration: Valuation of a number of entities for international arbitration purposes.

Various: Managed and provided business valuations services for companies engaged in a variety of industries throughout North American such as: pharmaceuticals, telecommunications, technology, power generation, senior's housing, agriculture, and various service companies.

Education/Professional Designations
Chartered Business Valuator, 1988
Chartered Accountant, 1984
Bachelor of Commerce (Honours), Queens University, 1981

Professional and Community Affairs
- Canadian Institute of Chartered Accountants
- Canadian Institute of Chartered Business Valuators (past Member of Board of Directors)
- Institute of Chartered Accountants of Ontario
- Provincial Institutes of Chartered Accountants (1992-2004 inclusive)
- Lectured at professional development seminars for the Ontario, British Columbia and Alberta Institutes
- St. Demetrius Development Corporation – Member Board of Directors (past)
- International Limited Partners Association Conference – Valuation Issues (2002)
- North American Valuation Summit on Financial Reporting Conference (2004)
- 2010 Private Equity Symposium, "Mark to Market: Private Equity Valuations in the Current Environment", Panel Moderator and Speaker (March 2010)
- Private Equity CFO Conference – Valuation of Portfolio Companies (2010)
- Financial Reporting and Accounting Conference – Fair Value Issues (2011)
- Acumen Information Services Conference, OSC, IFRS Update – Impairment Issues (2012)
- Acumen Information Services Conference – Fair Value Issues (2013)

Publications
- **Journal Articles:** Co-Author, "Goodwill Impairment Testing" Discussion Paper, Canadian Institute of Chartered Business Valuators
- **Other:** Co-Author, Industry Canada Website, "Steps to Capital Growth" Contribution Author, Business Acquisition Agreements

Robert B. Low, CA, CBV

Executive Advisor
Financial Advisory
Valuation & Dispute Services
Toronto
Phone: 416-775-7425   Email: rlow@deloitte.ca

Profile
Involved exclusively in business valuations, financial litigation and related matters since 1978, acting on behalf of shareholders and other parties (including Federal, Provincial and Municipal Governments) in connection with companies engaged in diverse industries.

Experience
2012 - Executive Advisor, Deloitte & Touche LLP (dispute practice leader in Greater Toronto)

2007 - 2012 Partner, Deloitte & Touche LLP

2004 – 2007 Director, LECG Canada, Ltd.

1998 – 2004 Principal, Low Rosen Taylor Soriano

1995 – 1998 Partner, Arthur Andersen & Co.

1978 – 1995 Partner, Campbell Valuation Partners Limited

Business valuations for:
- Corporate reorganizations
- Estate planning/settlement
- Expropriations
- International arbitration
- Matrimonial disputes
- Merger, acquisition and divestiture
- Public offerings/OSC rule 61-501
- Shareholder agreements
- Shareholder disputes/oppression remedies
- Tax purposes

Quantification of economic damages for cases involving:
- Business loss
- Contract disputes
- Commercial disputes
- Expropriation
- Intellectual property
- International arbitration
- Professional liability
- Class actions

Education/professional designations
- Chartered Accountant, 1974
- Chartered Business Valuator, 1980

- Bachelor of Commerce (Honours), 1972
- Certified Director, 2008

Acted As:
- Arbitrator – Commercial disputes
- Mediator – Commercial disputes
- Director of publicly traded mining companies

Qualified as an Expert Witness in:
- Ontario Superior Court of Justice
- Supreme Court of British Columbia
- Supreme Court of Prince Edward Island
- Supreme Court of Nova Scotia
- Court of Queen's Bench – Manitoba
- Court of Queen's Bench – Alberta
- Court of Queen's Bench – New Brunswick
- Federal Court of Canada
- Ontario Municipal Board
- Land Value Appraisal Commission – Manitoba
- Expropriation Compensation Board – British Columbia
- Alberta Energy and Utilities Board
- American Arbitration Association international arbitration
- NAFTA Arbitration under UNCITRAL Arbitration Rules
- Various private arbitrations

Professional and community affairs
- Institute of Chartered Accountants of Manitoba
- Institute of Chartered Accountants of Ontario
- Canadian Institute of Chartered Business Valuators
- Institute of Corporate Directors
- Ontario Expropriation Association (Director and past President)

Publications
Books/articles
- "The Valuation & Pricing of Privately-Held Business Interests" (Toronto: Canadian Institute of Chartered Accountants. Published 1990, co author.)
- Contributor: "Valuing a Business in Volatile Markets" (Toronto: Carswell. Published 2010)
- Various articles in trade magazines respecting valuation topics

Educational materials
- The Valuation of Business Interests; The World Bank (1995)

Lecturing
- York University - Combined MBA/LLB Programs - Seminars 1996 – 2013
- Schulich School of Business – MBA Program – 2008 and 2013
- Speaker at ADR Institute of Canada annual Conference 2007 - 2012
- Ontario Expropriation Association - Fall Conference, 1990 and 1996
- Canadian Institute of Chartered Accountants - Professional Development Programs, Lecturer
- and Seminar Leader in all provinces, 1979 - 1996
- The Valuation of Business Interests - The World Bank/Central Auditing Organization - Egypt (1995)
- University of Toronto Law School - Seminar - 1992 - 1995
- Law Society of Upper Canada - Professional Development Course - 1995
- Alberta Expropriation Association - Fall Conference - 1990
- Canadian Institute of Chartered Business Valuators - 1988 Biennial

Conference
- Member of the Final Examinations' Committee for the Canadian Institute of Chartered
- Business Valuators, 1981
- University of Manitoba - School of Administrative Studies, 1975 - 1976
- Society of Management Accountants (CMA) - Seminar Program, 1975
- Canadian Bar Association (Ontario) - Professional Development Courses
- Various Seminars for Insight, the Canadian Institute and Federated Press respecting valuation and damages topics