NON-CONFIDENTIAL

Request IR-1:

With reference to Application, page 15, lines 5-8, what electricity markets would have improved access with the Project?

Response IR-1:

The Project will provide access to Newfoundland and Labrador's hydroelectric resources and other sources of generation that are expected to be developed in NL as well as improve access to NB and New England markets.

NON-CONFIDENTIAL

Request IR-2:

With reference to Application, page 16, lines 2-6:

(a) Please explain and quantify how the Project will also increase Nova Scotia's capacity to develop new intermittent sources of electricity, such as wind, and incorporate them in the Nova Scotia's electrical transmission system.

(b) Please explain and quantify how the transmission upgrades postulated for the "Other Import" alternative would increase Nova Scotia's capacity to develop new Intermittent sources of electricity, such as wind, and incorporate them in the Nova Scotia's electrical transmission system.

Response IR-2:

(a) With the addition of the Maritime Link, a second interconnection to new, incremental and dispatchable renewable energy, NS Power will have the ability to schedule the NS Block daily and it will be able to optimize the daily profile of the NS Block within the agreed parameters. This will enhance the ability to respond to other intermittent sources like wind. Additionally, the Surplus Energy could be used to fill in for periods when wind production is below schedule.

(b) In the Other Import scenario, there is a required capital investment in the second interconnection or tie between NS-NB. This second tie will allow the import of energy and capacity and allow the first tie to remain available for balancing intermittent energy sources. The limitation of the "Other Import" is that the same market exists as with the original tie, therefore there is no new source of energy. NS Power's needs for the energy will increase the demand placed upon this market. The Maritime Link on the other hand brings new sources and potential new counterparties.

NON-CONFIDENTIAL

Request IR-3:

With reference to Application, page 17, lines 2, 13-14; page 105, lines 13-15; page 106, lines 3-4; page 149, line 12; and page 150, lines 3-4; please explain why only the Project but not the "Other Import" alternative supports the development of additional intermittent renewable energy resources in Nova Scotia, such as wind and tidal.

Response IR-3:

Please refer to SBA-IR2.

One of the benefits of an energy loop in Atlantic Canada, enabled through the Maritime Link, is the creation of an electricity market that has abundant supply of energy. The energy flowing through this new loop is reliable energy and of such quantities that it can serve as back-up for Wind and eventually tidal. The "other import" does not enable an energy loop and as a result could only import a specific amount of energy into Nova Scotia and would provide limited additional energy to support a back-up for wind or tidal.

It should also be noted that the location of the Maritime Link provides access to energy in the vicinity of where NS Power's coal fired units will be required to come off line to meet new Federal emissions regulations. This ensures that transmission capacity throughout the entire province will continue to be used when electricity starts flowing from Newfoundland and Labrador. Based on its location and where most of the energy demand is in Nova Scotia, the other import would leave these transmission assets underutilized in Cape Breton.

NON-CONFIDENTIAL

Request IR-4:

With reference to Application, page 18, lines 25, please quantify the remaining technical potential for hydroelectric generation in Nova Scotia. Distinguish new sites from nameplate expansions at existing facilities.

Response IR-4:

There are no further large scale (>30 MW) hydroelectric generation identified in Nova Scotia by NS Power. The sites that exist for small scale hydro are limited, as well as difficult to justify economically and environmentally. The two hydro river systems not developed in Nova Scotia are in salmon bearing rivers in sensitive ecological areas – Northeast Margaree River in Cape Breton and St Mary's River in Guysborough County on mainland Nova Scotia. NS Power considers neither to be viable from an environmental perspective alone. NS Power has very modest expansion opportunities at existing sites. Most of the improvement opportunity is in technologically upgrading components, automating the facilities and extending life through re-investment.

NON-CONFIDENTIAL

Request IR-5:

With reference to Application, page 18, lines 25-26:

(a) Please quantify the remaining technical potential for natural gas generation in Nova Scotia. Distinguish new sites from expansions at existing facilities. Please base the analysis on unused pipeline capacity.

(b) For new gas fired peakers or combined cycle plants located in Nova Scotia, what pipeline or local distribution system improvements would be needed, if any, to support gas assurance requirements for each technology type?

(c) For new gas fired peakers or combined cycle plants located in Nova Scotia, what upstream pipeline system improvements would be needed, if any, to support deliverability into the Province for each technology type?

(d) What assumptions did NSPML or its advisors make regarding the emergence of new natural gas supplies in New Brunswick, Sable Island, or Deep Panuke to support gas fired generation in Nova Scotia?

(e) What assumptions did NSPML or its advisors make regarding the utilization of the Repsol Canaport LNG import terminal over the study period to support gas fired generation in Nova Scotia?

NON-CONFIDENTIAL

Response IR-5:

(a-c) Natural gas generation limits in the province would be based upon existing infrastructure (generation and pipelines) and available supply, and the cost of the generation would be subject to market or contracted prices available. Currently, the Province is fed by a single pipeline that has a technical capacity of 600 mcf/day North to South if a source exists to fill the pipe. The Lateral pipeline to Halifax has a capacity of approximately 100 mcf/day, and can support the 500 MW of existing gas generation currently located in Dartmouth, Nova Scotia. Any further gas generation added to the Halifax lateral will restrict the potential to produce more electricity at peak demand. If we assume the 100 mcf/day supports 500 MW, the main line if only serving Nova Scotia (not New Brunswick and New England) and dedicated to generation only, we could assume 3000 MW would be possible (500MW/100mmcf x 600 mmcf= 3000 MW). There presently exists about 1000 MW of natural gas based generation in Nova Scotia and New Brunswick. The growth to 3000 MW would be an unrealistic level of capital investment without multiple pipelines and back-up generation alternatives.

(d) NSPML has not included any limitation on the use of natural gas generation in the modeling other than the emission constraints which would be required. NSPML is aware of the publicly stated plans of Exxon Mobil to initiate decommissioning plans for SOEP and the expected life Encana has proposed for Deep Panuke. NSPML is also aware of the progress in potential for shale gas development in New Brunswick. These were not used to modify or alter the natural gas price forecast used in the alternatives analysis. However, the expectation that SOEP may finish production by 2017 and that Deep Panuke has an expected life of 13 years would indicate that by the mid 2020's there is a higher degree of concern that gas prices will be pressured higher than lower for our region without new source development. Despite natural gas prices in the US being depressed by shale gas, the gas market in New England remains volatile and demand spikes place upward pressure on prices in our region.

NON-CONFIDENTIAL

(e) NSPML has not limited the use of any source of natural gas, including LNG imports, in selecting the use of natural gas generation in the dispatch plans for the alternatives. NSPML is aware that LNG is usually delivered to the basin which provides the highest benefit for the owners of the facilities, when the terminal was built the New England market was one of the highest price markets in North America. With the New England market prices somewhat suppressed due to the shale gas supply in that market, LNG is of higher value in the European and western Pacific markets than our region. However, LNG is still an added supply to our market and when it is being delivered it has downward price pressure due to supply. NSPML understands natural gas markets are subject to volatile prices and LNG may return to being a major source of supply but it has not effected the alternatives analysis which supports the Maritime Link as the lowest long term cost alternative.

NON-CONFIDENTIAL

Request IR-6:

With reference Application, page 22, lines 14-26, if the Maritime Link Project is not constructed, will Nalcor proceed with the construction of the Labrador-Island Transmission Link?

Response IR-6:

Yes. Please refer to the Sanction Agreement, which is Appendix 2.15 of the Application. See also the answer to CA/SBA IR-20.

NON-CONFIDENTIAL

Request IR-7:

With reference to Application, page 24, lines 8-9, please confirm that until more hydro and wind generation resources are developed in Newfoundland and Labrador, Nova Scotia will not have improved access to hydro and wind generation resources via the Maritime Link Project, or otherwise explain.

Response IR-7:

We do not agree with the statement presented. Please refer to CanWEA IR-26 (b).

NON-CONFIDENTIAL

Request IR-8:

With reference to Application, page 25, lines 1-3, please confirm that until 2041, when the Nalcor / Hydro Quebec contract ends, that Nova Scotia will not have improved access to generation from Upper Churchill Falls.

Response IR-8:

Please refer to CanWEA IR-26 (b).

NON-CONFIDENTIAL

Request IR-9:

With reference to Application, page 25, lines 13-16:

(a) Under the terms of Schedule 5 of the Energy and Capacity Agreement, within the day, upon notice of at least 60 minutes, does Emera have the right to request that the 30-minute schedule deliveries be changed provided that the total daily energy scheduled is not changed, and that the profile of delivery of the NS Block must remain within a band of plus or minus 40 MW? If no, please clarify what Emera's scheduling right is under this provision of the Agreement.

(b) Please explain and provide examples of how the Maritime Link could be used to provide backup to intermittent renewable energy sources such as wind and tidal power while respecting the minimum and maximum capacity limits, the 60 minute notice requirement and the daily energy obligation.

Response IR-9:

(a) Yes.

(b) The 80 MW output range of the Nova Scotia Block will allow for energy shaping through the day. In the case of wind the most accurate forecast timeframe is the next two hours so the notice period in the ECA aligns well. Tidal energy is very predictable, so the 60 minute period would allow for shaping of that energy.

NON-CONFIDENTIAL

Request IR-10:

With reference to Application, page 35, lines 4-7:

(a) What is the proposed size and development schedule of the new transmission line through New Brunswick?

(b) Will Nova Scotia customers be allocated any of the costs of building the new transmission line?

Response IR-10:

(a) The new transmission line is described in the New Brunswick Transmission Utilization Agreement (Appendix 2.07) as "a proposed 345 kV transmission line from the NS-NB border to the NB-Maine border to be constructed by Emera and/or one or more other parties". The capacity would be determined based upon system requirements at the time. There is no development schedule at this time.

(b) No.

NON-CONFIDENTIAL

Request IR-11:

With reference to Application, pages 52-53:

a) Describe how the subsea cable construction method will address depressions, scours and pockmarks encountered along the cable route.

b) Discuss how such depressions, scours, and pockmarks will be remediated if they develop after construction is completed and the subsea cable is installed.

Response IR-11:

(a) During offshore cable laying, an ROV will monitor the touch down point of the cable. Depressions, scours, and pockmarks will be identified visually, and the cable route altered to avoid them.

(b) After installation of the cable, if new pockmarks develop under the cable, and if the cable suspended length above the pockmark exceeds the design allowable free span, then remedial work such as careful leveling or rock dumping will be completed. The cable may be relocated if sufficient cable exists. The routine ROV inspection as part of the Operating and Maintenance plan will identify any concern areas.

NON-CONFIDENTIAL

Request IR-12:

With reference to Application, pages 51-53, provide a copy of any other marine surveys or other field studies undertaken along the subsea cable route.

Response IR-12:

The following table lists all marine surveys and field studies which have been completed along the subsea cable route. Due to the voluminous file sizes of these studies, they are not attached. We would be pleased to provide specific items upon request.

#	Study	Date	Author	File Size	Number of Pages
1	Subsea Cable Corridor Survey – Cabot Strait	December 21, 2011	Fugro GeoSurveys Inc.	29 MB	283
	Appendices to # 1	December 21, 2011	Fugro GeoSurveys Inc.	487 MB	29
	Enclosures to # 1	December 21, 2011	Fugro GeoSurveys Inc.	78 MB	7
2	Shoreline Surveys for Potential HVDC Cable Landing Sites	September 22, 2011	Fugro GeoSurveys Inc.	23 MB	137
3	CAST Vessel Traffic Report	December 2, 2011	NSPML	662 KB	47
4	Sediment Transfer Study	June 8, 2012	CBCL Limited	13 MB	95
5	MetOcean Study for Cabot Strait	March 2012	Oceans Ltd	6 MB	248

NON-CONFIDENTIAL

#	Study	Date	Author	File Size	Number of Pages
6	HDD Landfall Feasibility	May 2012	AMEC Environmental and Infrastructure	33MB	207
7	Cabot Strait Trenched Landfalls Feasibility Study	May 24 2012	Boskalis Offshore	9MB	135
8	Ice Risk Analysis for Cabot Strait Cable Crossing	December 2012	CCore	6.5MB	219
9	CAST Corridor Route Fishing Activity Analysis	January 27 2012	Canning & Pitt Associates	618KB	20
10	Updated Analysis of Fisheries Harvesting Activities and Catch Locations	April 25 2012	Canning & Pitt Associates	2.5MB	41
11	Cable Burial Study	August 2012	Intecsea	5.7MB	19
12	Weather Windows & Exceedance Analysis	December 18 2012	Oceans Ltd	133MB	2,161
13	Interpretation of Recent Survey Data Cabot Strait	February 10 2012	AMGC	1.3MB	17
14	Assessment of Near Shore Landing Site and Route Selection				
15	Micro-tunneling Analysis Report	February 3 2012	NSPML	538KB	10

Request IR-13:

With reference to Application, page 55, lines 13-18, with respect to the subsea cable route across Cabot Strait:

(a) Have studies of the depth to bedrock along the cable route been completed? If yes, please provide such data.

(b) What is the anticipated extent of bedrock cutting that will be required along the cable route?

(c) If project-specific data are not available, in preparing an estimate of capital costs and construction schedule, what assumptions have been made regarding the extent of bedrock cutting that will be required?

Response IR-13:

(a) Bedrock data is available in “Route Geophysical and Geotechnical Report (Fugro)”. Please refer to SBA IR-12.

(b) Bedrock cutting will not be performed along the cable route. This will be avoided by using HDD in the landfall areas, and micro-routing the cable using the seabed natural channels where sediment thickness will allow burial through ploughing or jetting.

(c) Bedrock cutting will not be performed.

NON-CONFIDENTIAL

Request IR-14:

With reference to Application, pages 51-53, describe the program for monitoring the integrity of the subsea cable portion of the Project over the lifetime of the Project.

Response IR-14:

ROV visual surveys will be performed along the cable route on a periodic basis. DTS fibreOP cable (5 km) on each end of the cable will allow monitoring of the cable temperature. Abnormal events will also trigger a review of possible need for an unscheduled ROV inspection, such as major ice seasons or intense hurricane in the region where coastal damage has been observed.

NON-CONFIDENTIAL

Request IR-15:

With reference to Application, pages 51-53, has the Cabot Strait, Laurentian Channel, or any other marine location in the vicinity of the Project ever been dredged for the purpose of improving navigation channels? If yes, identify the year and location. Are there any proposed plans to undertake dredging in the future?

Response IR-15:

We have no indication that dredging for the purpose of improving navigation channels have been performed in the past or will be performed in the future. The subsea cable as laid locations will be included on Cabot Strait navigation charts so that all mariners will be aware of their location. Sydney Harbour entrance was dredged in the last four years.

Request IR-16:

With reference to Application, pages 51-53, with respect to the potential hazard associated with pack ice and icebergs in Cabot Strait:

(a) What is the maximum extent of winter pack ice that has been observed in any year for which historical data have been recorded?

(b) What is the typical and maximum depth of pack ice and icebergs observed in Cabot Strait?

(c) What measures will be undertaken to protect the subsea cable and grounding facilities from ice scour?

(d) Provide copies of any Project-specific studies undertaken regarding pack ice and icebergs. If such studies are not yet available, provide the status and expected completion or filing date.

Response IR-16:

(a) Please refer to C-Core ice risk study for details, see SBA IR-12.

(b) Please refer to C-Core ice risk study for details. A conservative value for pack ice maximum depth is 25 m. A conservative estimate for iceberg depth on Newfoundland side is 100 m. icebergs on Nova Scotia side are not considered to be a risk.

(c) In the landfall area, the cable will be protected by HDD, and buried from the exit mouth of the HDD onwards.

(d) C-Core has completed an ice risk study for Cabot Strait. See SBA IR-12.

NON-CONFIDENTIAL

Request IR-17:

With reference to Application, page 57, lines 9-13, with respect to the potential hazard associated with currents, storm events, and waves in Cabot Strait:

(a) Provide copies of any studies that have been undertaken regarding the extent of scouring of the sediment along the route of the subsea cable. If such studies are not yet available, provide the status and expected completion or filing date.

(b) What measures will be undertaken to protect the subsea cable from the impact of strong currents and waves seasonally and during storm events?

Response IR-17:

(a) Please refer to SBA IR-12. Scouring studies along the seabed can be found in:

(i) Route Geophysical and Geotechnical Report (Fugro).

(ii) Sediment Transfer Study (CBCL).

(b) The cable will be buried and therefore waves and storm will not affect it, periodic routine ROV will be used to ensure the protection remains intact or is remediated.

NON-CONFIDENTIAL

Request IR-18:

With reference to Application, page 66, lines 15-19:

(a) Please explain whether or not the cost for expanding the Woodbine Substation, which includes a second 345/230 kV transformer and an extension of the 230 kV bus to facilitate two additional 230 kV transmission lines is included in the overall cost of the Maritime Link.

(b) If not, what is the cost?

Response IR-18:

(a) The cost for expanding the Woodbine Substation is included in the overall cost of the Maritime Link at an estimated cost of $28 million. There will not be two ‘additional’ 230 kV lines. Two existing 230 kV lines currently pass by the Woodbine Substation within 300 metres. These two existing 230 kV lines will be terminated at the Woodbine Substation as part of the 230 kV bus expansion.

(b) See response in (a).

NON-CONFIDENTIAL

Request IR-19:

With reference to Application, page 67, lines 9-11:

(a) Please identify all the transmission lines in Nova Scotia that will require localized relocations.

(b) Please provide the cost estimates for the relocations.

(c) Will there be any supply interruptions to Nova Scotia customers as a result of the relocations?

Response IR-19:

(a) A 1.5 km section of the 138 kV transmission line L-6538, near Highway 162, will need to be relocated.

(b) The cost estimate for this relocation is $1,191,083.

(c) No.

NON-CONFIDENTIAL

Request IR-20:

With reference to Application, page 74, lines 13-20, NSPML will contribute 20% of the total capital for the LCP Phase 1 project plus the Maritime Link Project. The LCP Phase 1 cost includes $0.7 billion (page 97) for the Labrador Transmission Assets which connect Muskrat Falls to Churchill Falls. NSPML clearly benefits from the Muskrat Falls Generation Station ($2.9 billion – page 97) and the Labrador-Island Transmission Link ($2.6 billion – page 97), along with the Maritime Link itself ($1.4 to $1.7 billion – page 77).

(a) Please explain how NSPML benefits from the Labrador Transmission Assets portion of the project.

(b) What is the economic rationale for the inclusion of the Labrador Transmission Assets portion of the project in the 20 for 20 Principle used to allocate total costs to Nova Scotia?

(c) Were other cost allocation principles contemplated by NSPML that significantly differed from the 20 for 20 Principle used to allocate total costs to Nova Scotia? If yes, please explain what alternative cost allocation principles were considered and why they were rejected.

Response IR-20:

(a-b) There are a number of reasons for inclusion of the Labrador Transmission Asssets:

1. The Labrador Transmission Assets are required to complete the transactions in totality including the performance of all contractual provisions regarding the supply of the NS Block.

2. The Labrador Transmission Assets allow for energy swaps between the Upper Churchill power house and Muskrat Falls to maximize energy production from the Churchill River system.

3. The interconnection between Upper and Lower Churchill completes the interconnection and looping of the electricity grids in Atlantic Canada and Quebec, which will improve overall reliability for the region.

(c) The 20 For 20 Principle was the result of negotiations that evolved over time. Various ideas were considered to deliver the best overall value to customers in Nova Scotia and Newfoundland and Labrador. Other options were not accepted because the 20 percent investment in exchange for 20 percent of the energy is the best option. Please refer to NSUARB IR-77.

NON-CONFIDENTIAL

Request IR-21:

With reference to Application, pages 91-92, Section 4.13:

(a) Please provide a table of the quantities of energy purchased by month by NPSI through the Maritime Link in addition to the Nova Scotia Block in the Strategist modeling of the Maritime Link Project for the Base, High, and Low market price scenarios.

(b) Please provide a table of the market prices paid by NSPI for energy purchased through the Maritime Link in addition to the Nova Scotia Block in each month in the Strategist modeling of the Maritime Link Project for the Base, High, and Low market price scenarios.

(c) Do the purchase prices in the Strategist modeling include GHG Credits or other credits attributable to renewable electricity?

Response IR-21:

(a) Please refer to Synapse IR-11 (c).

(b) Please refer to NSUARB IR-37 Attachment 1.

(c) No.

NON-CONFIDENTIAL

Request IR-22:

With reference to Application, page 101, line 19 to page 102, line 9:

(a) Does the Ventyx Strategist model use dynamic programming to produce resource addition and retirement plans?

(b) If yes, is Strategist designed to find the optimal mix or portfolio of resources over the Planning Period? If no, describe the basic method it uses for long-term resource planning.

(c) Please provide a complete explanation of any structural limitations (e.g., simplifying assumptions, problem size or complexity limits of the optimization approach) associated with Strategist that prevent model use from optimizing the portfolio of resources to serve Nova Scotia Power Incorporated (NSPI) resource requirements over the study period.

(d) Why did NSPML not require Ventyx to apply the Strategist model to analyze possible optimal combinations among the seven options?

(e) Could Ventyx have applied the Strategist model to analyze possible optimal combinations among the seven options if they had wanted to perform such analysis?

Response IR-22:

(a-b) Yes.

(c) Please refer to SBA IR-61.

NON-CONFIDENTIAL

(d-e) NSPML did request Ventyx to optimize the three alternatives for each load case. In each of these six resource plan optimizations Strategist was able to choose from the four natural gas options as to the timing and number to add. Please refer to SBA IR-70.

NON-CONFIDENTIAL

Request IR-23:

With reference to Application, page 101, line 19 to page 102, line 9, please provide the Strategist user guide.

Response IR-23:

Ventyx considers the Strategist documentation, as well as the software itself, to be its sole intellectual property. As such it is proprietary and confidential information. Ventyx will only grant access to the Strategist documentation under a license agreement or a Non-Disclosure Agreement between the receiving party and Ventyx Inc.

Request IR-24:

With reference to Application, page 101, line 19 to page 102, line 9:

(a) Does Ventyx have a Strategist technical reference guide for client use?

(b) If yes, please provide.

(c) If your answer to part (a) is no, please provide a detailed description of the Strategist model components and their mathematical structure and assumptions prepared byVentyx. The technical description document should describe the scope and limitations of the optimization capabilities of Strategist with respect to both long-term resource planning decisions (build, retire, repower, retrofit) and system commitment and dispatch decisions. Other model aspects to describe (among others) include:

(i) Method for modeling transmission constraints and power flows;

(ii) Methods for modeling forced, planned, and scheduled outages;

(iii) Method and extent of modeling daily, weekly, and seasonal unit commitment decisions for energy dispatch;

(iv) Method for modeling planning reserves, accounting for inter-area transfers;

(v) Method for modeling operating reserves;

(vi) Method for modeling multi-area energy markets.

NON-CONFIDENTIAL

Response IR-24:

(a-c) Please refer to SBA IR-23.

NON-CONFIDENTIAL

Request IR-25:

With reference to Application, page 101, line 20 to page 102, line 2. Please provide for the Ventyx assignment:

(a) **Any Request for Proposals or Request for Qualifications document that led to the selection of Ventyx.**

(b) **All contract documents, email, or memoranda with Ventyx pertaining to the scope-of work.**

(c) **Any other scope-of-work and other assignment-related documents**.

Response IR-25:

(a) A Request for Proposals or Request for Qualifications was not issued. Ventyx was selected because they are the vendor for the Strategist® model that NS Power uses for long term planning. Please refer to page 102, line 1-9 of the Application.

(b-c) Please refer to Attachment 1. The fees and costs have been redacted.

Attachment A

Statement of Work

1 INTRODUCTION AND OBJECTIVES

The Maritime Link (ML) involves the construction and operation of a new 500 megawatt (MW), +/-200 to 250 kV high voltage direct current (HVDC) and high voltage alternating current (HVAC) transmission line, the main elements of which include:

- transmission corridors (HVDC transmission, HVAC transmission, grounding system transmission lines;
- subsea cables;
- shore grounding facilities;
- two converter stations and adjoining substations;
- two transition compounds (for converting underground subsea cables to overhead transmission conductors); and
- other potential infrastructure, as required.

Emera Newfoundland Labrador (ENL) will be seeking regulatory approval of the project through an application to the Nova Scotia Utility and Review Board (NSUARB). It is anticipated that this application will be made by September 30, 2012. In advance of that application ENL requires analyses to be completed to determine if the ML is the lowest long term option for Nova Scotia (NS) customers given the environmental and regulatory requirements in NS.

Ventyx, having previously executed modeling and analysis work for Emera and NSPI in relation to the ML project, and having a significant degree of specialized expertise as a result, has both the capability and the desire to perform the analyses requested by Customer. Ventyx will execute the analyses as described in this Statement of Work (SOW).

2 SCOPE OF WORK

Using existing NS system models in Strategist, Ventyx will perform a base case analysis. Updates to the model base assumptions will be provided by Nova Scotia Power Inc. (NSPI) and ENL as required. Once the model is updated with current information the following base case and two scenarios will be run.

Maritime Link Option
Northern Import
Indigenous Wind

Alternative 1- details to come from economic model and NSPI cost assumptions for redispatch.
Alternative 2 – Northern import pricing to come from ENL
Alternative 3 – Pricing to be provided by NSPI

Once the initial runs have been completed, additional sensitivities will be required. We anticipate those to be low load and high gas. Others may be required once the initial analysis is completed.

3 ESTIMATED SCHEDULE & DELIVERABLES

The following estimated schedule and deliverables have been identified within this Statement of Work (SOW). This estimated schedule assumes that a finalized agreement and SOW is signed by the customer and returned to Ventyx by August 17, 2012.

3.1 Estimated Schedule of Work

The schedule of work outlined below is dependent on the timely delivery to Ventyx of all data to be provided by Emera/NSPI.

Description	Dates
Task A - Administrative and General	Throughout
Task B - Update Strategist model for current forecasts	Aug. 31, 2012
Task C - Run Two Additional Scenarios	Sept. 7, 2012
Task D - Sensitivities	11-Sep-12
Task E - Reporting	Sept. 17, 2012

3.2 Deliverables from Ventyx

Ventyx will deliver the following items under this Statement of Work (SOW):

- Reports detailing the model results and in a mutually agreed upon format will be provided to the customer at;
- The completion of the Base Case Updates; and
- At the completion of the runs for each of the three scenarios and two already defined sensitivities.
- The same report format will be used for any optional scenarios or sensitivities requested by the customer.

3.3 Deliverables from Customer

- The Customer will deliver the following items to support the activities for this Statement of Work (SOW):
- Will provide assistance to Ventyx to identify the desired starting point database for this project from the commercial studies work previously performed by Ventyx for Emera/NSPI.
- All updates for load forecasts, fuel prices, generator operating costs and parameters

3.4 Assumptions

- The following assumptions have been made when producing this Statement of Work (SOW):
-
- Services will be provided remotely, unless Emera\NSPI subsequently requests that Ventyx perform some of the work described in this SOW on-site.
- The starting point database that is to be updated for the Base Case can be readily identified from previous work between Ventyx and Emera/NSPI. This database is further assumed to be one of the commercial studies databases used in joint work with Nalcor and Emera/NSPI by Ventyx.
- Emera/NSPI will provide the required data updates in a timely manner and in accordance with the schedule of work as delineated in this SOW.
- All reports, spread sheets, or other results or presentations are to be delivered electronically.

- The Ventyx project manager will provide a single point of contact between Customer and Ventyx with regard to scope, schedule, and resources assigned to accomplish the Ventyx services.
- Ventyx consultant(s) will work under the direction of a Ventyx Project Manager or designee.
- If any work is to be performed at Customer's facility, Customer will provide adequate office facilities in close proximity to the designated members of the customer staff assigned to work with Ventyx on this project. Facilities for each consultant will include Internet access for accessing Ventyx intranet using Ventyx laptop computers.
- Customer will provide functional and technical resources as needed throughout the life of the project that will serve as core team members, subject matter experts and project execution resources.
- Ventyx's delivery of the Services is dependent on (i) Customer's timely and effective completion of the Customer Responsibilities, (ii) the accuracy and completeness of the Assumptions, and (iii) timely decisions and approvals by Customer's management. Additional fees and charges may be applicable for deficiencies or delays in Customer Deliverables.
- No Site Acceptance Test or Warranty is applicable.
-

4 CHARGES

4.1 *Fee Summary*

The fee(s) for this SOW is an estimated [redacted] and will be performed on a Time and Materials basis, exclusive of expenses and taxes. The estimates provided below are intended to be an estimate for budgetary and Ventyx resource scheduling purposes only.

All fees presented in this SOW are expressed in Canadian Dollars unless stated otherwise.

Estimated Hours and Costs for Maritime Link Alternatives Analysis

Hours	$	Description
8	$ [redacted]	Task A - Administrative and General
44	$ [redacted]	Task B - Update Strategist model for current forecasts
16	$	Task C - Run Two Additional Scenarios
12	$	Task D - Sensitivities
36	$	Task E - Reporting
116	$ [redacted]	Total

Optional Tasks

8	$ [redacted]	Task H - Additional Sensitivity Runs (average for each run)
0	$ -	Task I -

4.2 *Travel Expenses*

Any travel expenses will be charged at cost. When it is necessary for the Ventyx resources to be on-site for an entire week, Ventyx will utilize a 3/4/5 travel schedule. A 3/4/5 travel schedule consists of the Ventyx resources travelling to the Customer site Monday morning and returning Thursday evenings. The Ventyx resources will be on-site three nights, four days, and working in their respective Ventyx office's on the fifth day

No travel is anticipated for this SOW and thus no estimate of travel expenses is provided.

Ventyx's Expense Reimbursement Policy is set forth in Attachment A.

4.3 Payment Terms

Ventyx will invoice monthly in arrears for T&M. Invoices are due upon receipt and payable within thirty (30) calendar days after the date of each invoice.

NON-CONFIDENTIAL

Request IR-26:

With reference to Application, page 102, lines 1-9:

(a) Please provide the docket IDs and documents (or UARB website links) that describe Strategist modeling methods, inputs (data and assumptions) and outputs that were submitted to the UARB for the most recent three capital projects or integrated resource plans that NSPI used Strategist to compare alternative generation and/or transmission long-term plans.

(b) Please provide the docket IDs and documents (or provincial/state or federal website links) that describe Strategist modeling methods, inputs (data and assumptions) and outputs that were submitted to other provincial, state or federal regulatory commissions by Emera Canadian and US subsidiaries within the past five years.

Response IR-26:

(a) Please refer to matter P-884 on the UARB website to access the 2007 IRP and 2009 IRP Update. The following context was provided to help stakeholders understand how Strategist was used:

> Strategist is a long term generation planning tool and as such uses load duration curves and probabilistic techniques to dispatch thermal units in order to reduce processing time when optimizing expansion plans. Operational issues such as load following, maintaining operational reserves, and tie line load control require an hourly dispatch model. This level of detail is not appropriate for directional long term planning purposes, and is not incorporated in the Strategist model.

(b) There are none.

NON-CONFIDENTIAL

Request IR-27:

With reference to Application page 102, line 4-7, please provide copies of all studies and reports prepared by or for the Atlantic Energy Gateway initiative.

Response IR-27:

Please refer to Attachments 1 through 8.

Financing of Renewable Electricity Projects in Atlantic Canada

Prepared for:

Atlantic Energy Gateway

Atlantic Canada Opportunities Agency

March 28, 2012

Power Advisory LLC

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978 369-2465

Table of Contents

1 Introduction and Purpose

The Atlantic Canada Opportunities Agency (ACOA) is conducting the Atlantic Energy Gateway (AEG) study to facilitate the development of Atlantic Canada's clean energy resources. As part of this initiative, ACOA engaged Power Advisory LLC (Power Advisory) to identify and analyze the challenges to financing of renewable energy projects by independent power producers (IPPs) in each of the four Atlantic Provinces. This study identifies and evaluates the key factors that affect the availability and cost of capital for Atlantic Canada renewable projects developed by IPPs. The purpose of this study is to identify the necessary economic and market conditions and appropriate policies and government actions to support renewable project financings under reasonable terms and conditions so that the Atlantic Provinces can take full advantage of the opportunities offered by the region's renewable and clean energy potential.

1.1 Report Outline

In this report Power Advisory reviews the key factors that affect the availability and cost of capital for renewable projects developed by IPPs and assesses the degree to which there are policies that can be employed and changes to market conditions that can be made to facilitate the financing of these projects so that the region's full renewable energy potential can be realized.

The report first reviews the level of renewable project development in each of the four Atlantic Canada provinces as well as the policies that support the development of these projects. Chapter 3 assesses the project attrition rate for renewable energy projects in Atlantic Canada to provide an indication as to whether it is more difficult to develop and finance renewable energy projects in Atlantic Canada than other regions. The chapter then review3s the results of and insights from a phone survey that we conducted with over 20 renewable project developers and financiers that are active in Atlantic Canada. Finally, Chapter 3 concludes with a review of the results of our literature search regarding the financing of renewable energy projects. Chapter 4 reviews the critical determinants of the cost of capital including critical project risks that must be managed by renewable project developers and can be reflected in project's cost of capital to the degree that they aren't adequately mitigated. Chapter 5 provides an overview of current capital market conditions and assesses the implications for financing renewable projects by reviewing terms that are available to project developers. Chapter 6 reviews financing options for Atlantic Canada, policies to facilitate financing, and financing approaches employed in other jurisdictions by reviewing various case studies. Chapter 7 reviews policies that can be employed to facilitate the financing of smaller renewable energy projects which pose the greatest challenge and then discusses policies that can expand the scope of provincial electricity markets. Chapter 8 offers descriptions of strategic policy options for further consideration by the AEG committee members and Atlantic Canada governments.

Appendix A is the Interview Guide that we used to survey renewable project developers and financial industry professionals regarding the challenges associated with financing renewable energy projects in Atlantic Canada. Appendix B summarizes our findings from these surveys. Appendix C provides a broader review of policies to facilitate the financing of larger renewable energy projects developed by IPPs.

2 Review of Renewable Project Development in Atlantic Canada

This section provides a review of the level of renewable project development by IPPs and the major policy initiatives and programs to promote the development of renewables that have been implemented in each Province in Atlantic Canada. Finally, the major transmission interconnections in the region are identified and contrasted with peak load and existing generating capacity to provide an indication regarding the potential implications of market size and existing transmission infrastructure on renewable project development.

2.1 New Brunswick

Currently 28% of the electricity consumed in New Brunswick comes from renewable resources including hydroelectric, wind and biomass generation.[1] The vast majority of this is provided by seven hydroelectric facilities providing 895 MW, which are owned and operated by NB Power. Other renewables include 294 MW of wind generation developed by IPPs and a 38 MW biomass project at the Twin Rivers Paper Company. The output of these wind projects was procured by NB Power under two separate RFPs.

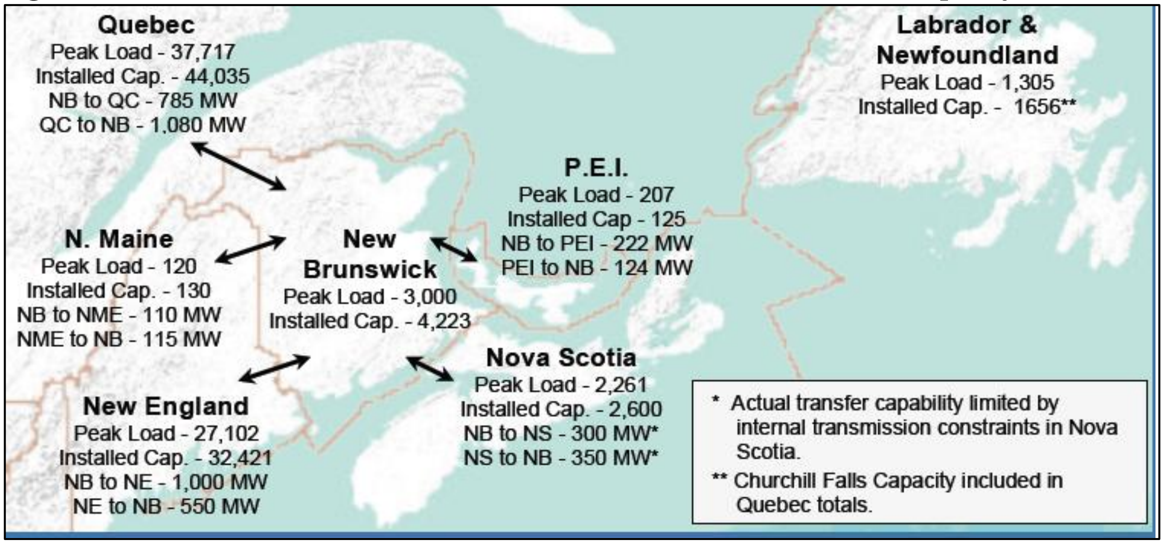
In October 2011, the New Brunswick Government released its *Energy Blueprint* which creates a new Renewable Portfolio Standard of 40% of NB Power's total in-province sales by 2020. With respect to renewable energy initiatives, the *Energy Blueprint* calls for: (1) supporting local and First Nations small-scale renewable projects; (2) integrating wind generation in the most cost-effective and efficient manner; and (3) supporting solar, bio-energy and other emerging renewable energy technologies. The *Energy Blueprint* also outlines a Large Industrial Renewable Energy Purchase Program under which NB Power would purchase the output from renewable energy projects owned by large industrial customers. The *Energy Blueprint* also indicates that "NB Power will procure new renewable energy resources through competitive Requests for Proposals (RFP) and projects will be evaluated on criteria to be released prior to each RFP. These criteria will include the net economic and social benefits to the community, cost of energy production, rate of return, business plans, size of project, and cost of integrating the generation into the grid."

As is evident from Figure 1, New Brunswick is well connected with the rest of Atlantic Canada and is the only province in the region that is directly connected with New England. Five of the six New England states have renewable portfolio standards which require 18 TWh of renewable energy by 2020, greater than the total forecast energy requirements of New Brunswick and PEI.

New Brunswick has an independent system operator which serves as the balancing authority for New Brunswick, Northern Maine and PEI. Under the *Energy Blueprint* it will be folded back into NB Power.

[1] New Brunswick Department of Energy, *The New Brunswick Energy Blueprint (Energy Blueprint)*, October 2011, p. 20.

Figure 1: Transmission Interconnections vs. Peak Load and Generation Capacity



2.2 Newfoundland and Labrador

Newfoundland and Labrador has three IPP wind projects which provide about 54 MW. The Island of Newfoundland, where these projects are located, isn't currently connected with the Eastern Interconnect. However, Nalcor Energy has proposed the development of Muskrat Falls, an 824 MW hydroelectric facility located in Labrador. As part of the development of this project, Emera Energy would receive about 1 TWh of energy per year from the project and in return build transmission, the Maritime Link, which would connect Newfoundland and Nova Scotia. The Maritime Link will connect the Province to the rest of Atlantic Canada.

2.3 Nova Scotia

About 17% of Nova Scotia's electricity supply is provided by renewable energy resources, including almost 400 MW of hydroelectric and tidal generation owned and operated by NSPI.[2] This includes about 300 MW of wind generation, of which about 82 MW are owned by NSPI.[3]

Nova Scotia has a requirement of 25% renewable electricity generation by 2015 and a target of 40% by 2020. This includes an additional 300 GWh from IPPs to be procured under an RFP process administered by an independent Renewable Electricity Administrator, with an equivalent amount of renewable energy to be developed by NSPI. In addition to renewable energy development by IPPs and NSPI, Nova Scotia has implemented a feed-in tariff for community renewable energy projects (COMFIT) and a feed-in tariff for Developmental Tidal Arrays.

As of February 2012, over 95 applications have been submitted and twenty, representing about 50 MW, have been approved by the Province. Of the twenty COMFIT applications that have been approved ten are being developed by Community Economic Development Investment Funds (CEDIFs), five by municipalities, one by a university, one by a First Nation, two are for Tidal

[2] http://www.nspower.ca/en/home/environment/renewableenergy/default.aspx

[3] A 31.5 MW project is under construction and scheduled to be in commercial operation in the first quarter of 2012.

Arrays, and one is an industrial biomass-fired combined heat and power project. Around 90% of applications have been for wind projects. Of these, most are large wind (>50 kW), with about ten percent of wind projects small wind projects. Several applications have also been submitted for biomass and in-stream tidal projects. Eleven of the approved projects are large wind for a total of 44 MW, six are small wind for a total of 73.5 kW, the two Tidal Arrays total 2.45 MW and the biomass CHP is 3.3 MW. The province expects about 100 MW to be produced by the COMFIT.

2.4 Prince Edward Island (PEI)

Reflecting its exceptional wind resource, PEI has 173 MW of wind capacity,[4] for an electricity system that has an average load of 145 MW.[5] Maritime Electric purchases 52 MW of wind generation from the PEI Energy Corporation's North Cape and Eastern Kings wind farms and 10 MW from the WEICan facility. As well, the City of Summerside has developed a 12 MW wind farm to serve a portion of the City's load. In addition, a 99 MW wind farm was developed and financed based on the sale of energy to New England which requires that the power be wheeled through New Brunswick.

Maritime Electric is part of the NB Power control area, which facilitates balancing. However, Maritime Electric is responsible for imbalances that it incurs on the NB Power system as a result of the variability of wind.[6]

In October 2008, the Government of Prince Edward Island announced the province's wind energy strategy, *Island Wind Energy, Securing Our Future: The 10 Point Plan*. The province's goal is 500 MW of wind power to be installed by 2013. The 10-point plan focuses on benefiting the local community and providing opportunities for developers by setting clear ground rules and establishing a fair, open and transparent process for developers.

[4] Including the 10 MW WEICan facility now commissioning.
[5] Including Maritime Electric and the City of Summerside jurisdictions.
[6] The wind in PEI and Northern Maine result in 502 MW of wind which must be balanced by NB Power, resulting in one of the highest proportions of wind generation in North America. (*Energy Blueprint*, p. 22)

3 Evidence on Financing Renewable Energy Projects in Atlantic Canada

The RFP posed three basic questions:

1) Is there a shortage of equity and debt financing available to renewable energy projects in Atlantic Canada and if so what financing vehicles can improve the availability of capital?
2) In what ways are there greater risks associated with renewable energy projects in Atlantic Canada than in other jurisdictions, including the rest of Canada? How can these risks be mitigated for investors? Are there gaps in the information that investors require?
3) Do projects developed in Atlantic Canada have disproportionately high technology risks (e.g., tidal projects)?

We have addressed these questions by surveying participants in the Atlantic Canada renewable energy market and by researching the market. We have also reviewed the available literature for information on the issues associated with financing of renewable energy projects in general and on such issues within Atlantic Canada. This literature review is also presented in this Chapter. However, prior to reviewing the findings from these interviews and this literature review, the attrition rate for renewable projects in Atlantic Canada is reviewed.

3.1 Project Attrition Rate Assessment

An important indicator regarding the health of the renewable project market in Atlantic Canada is the level of project attrition relative to other markets.[7] A higher level of project attrition indicates that there are greater project development risks in Atlantic Canada than other jurisdictions. One challenge with such an analysis is the lack of transparency regarding project development efforts which makes it harder to establish the level of project development activity.

A key determinant of project success is the market's need for renewable capacity. A region with favourable renewable resource potential, but relatively limited demand for renewable energy, is likely to have a higher proportion of proposed projects that don't get contracts and therefore don't achieve commercial operation.[8] Our focus is on projects that were awarded contracts in RFPs and demonstrated themselves to be attractive proposals or secured contracts under Nova Scotia's COMFIT or New Brunswick's Community Energy Policy, but weren't ultimately successfully developed given project development barriers. The experience in Nova Scotia, based on a 2007 Renewable Energy RFP, and New Brunswick, based on its two renewable energy RFPs, is reviewed below.

[7] Project attrition here refers to projects which succeed in RFP processes or otherwise obtain contracts but are never built.
[8] A number of developers made this comment, i.e., the primary constraint to successful project development efforts is the size of the market.

3.1.1 Nova Scotia's Experience

Nova Scotia Power Inc.'s (NSPI's) 2007 RFP was for 130 MW. Power Purchase Agreements were signed for 246 MWs, with 252 MW ultimately built. NSPI elected to contract with more than its procurement target to compensate for anticipated project attrition which it estimated to be 20 to 30% based on the experience in California.[9]

The additional 6 MW built versus contracted (i.e., 252 MW versus 246 MW) reflects the additional capacity provided by changes in wind turbines. Of this capacity, 81 MW was ultimately built by NSPI when IPPs were unable to deliver on their contractual commitments.[10] The developer of one of these projects (SkyPower) sold its interests in the project after its major equity investor Lehman Brothers was liquidated. Another project, Amherst Wind Energy Project, which was originally proposed by Acciona Wind Energy Canada Inc., has subsequently been sold to Sprott Power Corp. and is under construction.

Therefore, while all of the capacity that was contracted by NSPI under its 2007 RFP was built, the terms under which a number of these projects were constructed differed from those outlined in the original RFP. A primary contributor to these changes was the financial crisis in 2008 which caused an unprecedented increase in debt costs. This is shown in

Figure 2 which presents long term bond rates from 2006 to 2011 (through October) and shows how interest rates for Baa Bonds rated by Moody's Investor Services increased from about 6.5% in 2007 when proposals were submitted to around 8.5 % to 9% from October 2008 to April 2009.[11] This increase in financing costs made financing very difficult for projects that were attempting to secure debt during this period.

Given stakeholder concerns stemming in part from NSPI's acquisition of projects and with the RFP process, the Nova Scotia Government established an independent Renewable Electricity Administrator (REA) to administer future RFP processes for renewable energy resources.[12]

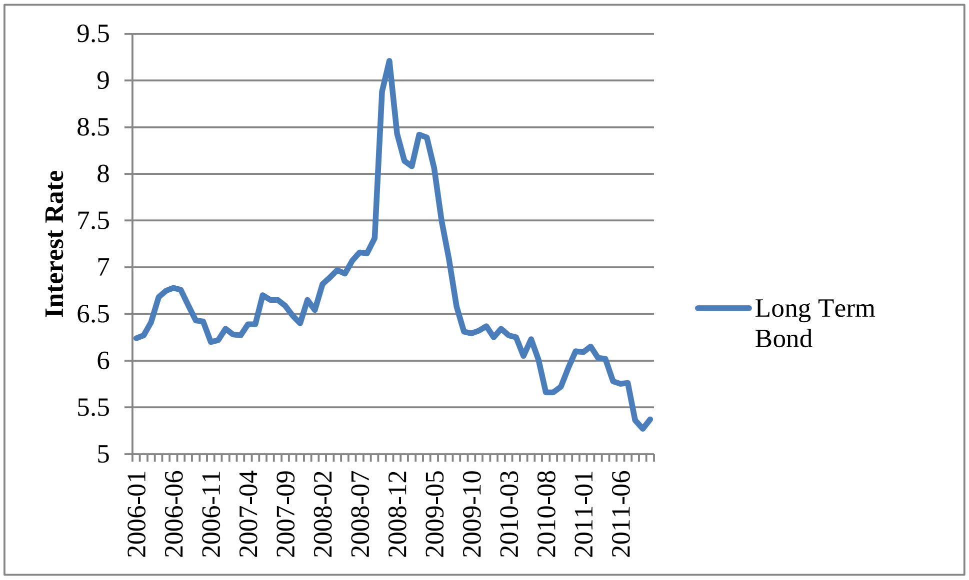
3.1.2 New Brunswick's Experience

NB Power has issued two RFPs for wind energy which have resulted in the development of 294 MW of wind generation from four projects including two at the same site.[13] A contract for 64.5

[9] Specifically, NSPI relied upon the following study performed for the California Energy Commission. "Building a Margin of Safety into Renewable Energy Procurements: A Review of Experience with Contract Failure" CEC 300-2006-004, January 2006.
[10] The Nuttby Mountain (50.6 MW) and the Digby Neck (30 MW) projects.
[11] These interests are for US bonds given the availability of data, but a similar increase in interest rates was experienced in Canadian bonds.
[12] Power Advisory was appointed as the REA by the Government of Nova Scotia. This model has specific challenges given that the REA designs the RFP; drafts the PPA; and selects the Proponents to be awarded PPAs, whereas, the PPA is ultimately executed by the IPPs selected and NPSI.
[13] These are 99 MW at Caribou Mountain, owned by GDF Suez; 150 MW at KentHills, owned by TransAlta, and 45 MW at Lamèque owned by Acciona. KentHills was contracted in two phases.

MW was awarded to Acciona Energy North America for a project in Aulac in early 2008.[14] This project hasn't been built, with delays reported to be attributable initially to adverse financial conditions and then permitting issues, i.e., Acciona must perform a two-year avian study given the project's location next to a marsh. Development delays prevented the project from participating in the ecoENERGY for Renewable Power Program, which in turn caused its PPA with NB Power to be terminated.

Figure 2: Long Term Bond Rates 2006 to 2011



Source: US Federal Reserve Data

3.1.3 Conclusions

Based on this review, Power Advisory believes that Atlantic Canada hasn't experienced higher project attrition rates than other parts of Canada. Project attrition rates in other markets range from about 13% (for the Renewable Energy Supply III RFP issued by the Ontario Power Authority) to the 20% to 30% experienced in California.

Project delays and the sale of project interests are attributable to overall financial conditions rather than any issues specific to Atlantic Canada. Interestingly, one developer that was associated with two projects which were considerably delayed was a large international renewable project developer which would be more likely to have the financial resources to weather such economic conditions.

3.2 Survey results

One of the three basic questions was whether there is a shortage of finance for renewable energy investment in Atlantic Canada and, if so, what policies might address these shortages. To help answer this question, we interviewed a wide range of market participants (developers and financiers) with experience or involvement in the development of renewable energy projects in

[14]http://www.nbpower.com/html/en/about/media/media_release/pdfs/WindAnnouncementJan28.pdf

Atlantic Canada. [15,16] All of the developers have been active in renewable resource development in Atlantic Canada, and most have also been active in renewable resource development elsewhere in Canada and the world.

Most of the interviews were conducted by telephone. At least two members of the project team participated in most of the interviews.

Both developers and financiers told us that location in Atlantic Canada does not create any disadvantage or differences compared to the rest of Canada in terms of availability of finance or of expertise on development of renewable electricity projects. A project in Atlantic Canada will be evaluated by financiers on the same terms as in the rest of Canada.[17] The evaluation will be by the same teams or by teams with the same knowledge of the industry. The initial challenges associated with financing projects in Atlantic Canada and some of the development difficulties were attributable to the more limited experience of local developers and smaller project sizes of the initial projects. This made it more difficult to realize economies of scale and some of the inexperienced developers structured projects in ways that made securing financing more difficult.

Several companies we interviewed have experience developing renewable energy projects in more than one province in Atlantic Canada and in other parts of Canada. They consistently said that the issues they faced in raising financial capital were the same in Atlantic Canada as elsewhere. Financiers are interested in the quality of the power purchase agreement (PPA), the creditworthiness of the offtaker, the experience and technical capability of the developer and the development team, and the financial stability of the developer.[18] They want to know that risks are identified, appropriately mitigated, and assigned to appropriate parties (i.e., the party that is best able to manage these risks). Large, experienced, well-supported renewable project developers, therefore, are able to access financing for their projects in Atlantic Canada under essentially the same terms as they are in the rest of Canada.

Some companies that have experience developing renewable projects in other provinces commented that some aspects of the development process are easier in Atlantic Canada. In particular, environmental permitting and aboriginal issues do not require as much time as they do in other jurisdictions.

Many of our interviewees pointed out that the conditions for financing renewable projects are quite different for small projects than for large projects, especially if the developer is also small

[15] Our interview guide is attached as Appendix A.
[16] The interview notes for those parties that authorized the release of the notes are attached as Appendix B.
[17] As discussed further below, this isn't necessarily true for small renewable projects which are more likely to rely on local lenders rather than lenders that specialize in renewable energy project finance and finance renewable energy projects across Canada.
[18] Not surprisingly, this is the same as in the US where a recent report by Mintz Levin found that "High-quality projects sponsored by experienced developers [which] have signed power purchase agreements ("PPAs") from credit-worthy off-takers will continue to secure project financing..." (*Renewable Energy Project Finance in the U.S.: 2010-2013 Overview and Future Outlook*, January 2012, p.7)

and relatively inexperienced.[19] The major financial institutions, banks and insurance companies, consistently said that they are generally not interested in projects where the total financing is below $50 million (a wind project of about 30 to 35 MW), though some said they might consider projects as small as $30 million.[20,21] The reason for this size threshold is simple: these institutions have finite resources to perform the required analysis and due diligence for projects and it costs them almost as much to do this for small projects as for large ones. Given the corporate expectation that they will lend a certain amount, they cannot afford to spend these limited resources on small projects. The institutions emphasized that this size threshold did not apply only to Atlantic Canada; it would apply anywhere in Canada or elsewhere.

Several interviewees also noted that, in their experience, small developers are more likely to have less development experience, to be more prone to overlook key risk factors or to make other mistakes in project structure, and in general to require more assistance from the lenders. This experience is not surprising as project developers are keenly focused on the success rate of their projects, and experienced developers will chase larger projects which offer larger returns for the same level of development effort as a smaller project. This experience reinforces the banks' reluctance to undertake relationships with such smaller developers. Further, small developers will have more difficulty accessing capital for such projects. For example, bank applications for smaller loans (say, up to $10 million) would be made to the local or regional commercial loan departments, which will not have expertise in lending to renewable developers and would not have ready access to such expertise from elsewhere in the bank. In addition, the due diligence and structuring costs can overwhelm the economics of a smaller project.

As the interviewees noted, the size of the market for renewable resources in Atlantic Canada significantly affects renewable energy development in the region. Since the overall Atlantic Canada electricity market is small relative to other areas, the amount of renewable capacity that can be integrated and the amount of renewable energy needed to meet a requirement like a Renewable Portfolio Standard (RPS) is also small. Therefore, the possible number of projects large enough to attract interest from these financial institutions is also small. The survey respondents said that this limits the number of companies that can participate in the market.

Some developers, especially those who are primarily focused on Atlantic Canada, commented on this limit on opportunities for larger developments in Atlantic Canada. They also noted that the limited number of winners in an RFP process, like those in New Brunswick and Nova Scotia, increases their risk of participation in the RFP process. The cost of participation in the RFP process for a small developer is a significant portion of its total resources. With only a few winners, and with competition from large developers, the small developer sees only a small chance of winning a contract. The small developers suggested that this is less of a problem for

[19] The previously referenced Mintz Levin Report offered a similar finding: "Project financing constraints are likely to disproportionately impact smaller projects, less established developers, and/or projects with higher technology or regulatory risks." (p. 7.)

[20] Some also said that they preferred projects at or below $100 million because above that size they will look for participation from other lenders. Some financiers preferred to finance larger projects, in the $200 million to $400 million range, but would look at projects as small as $50 million.

[21] This reflects a 70/30 debt/equity ratio and project capital cost of about $2,200/kW.

the large diversified developers who have a portfolio of existing and potential projects to draw from and can therefore afford to participate in an RFP and lose.

In general, smaller developers preferred a feed in tariff (FIT) process for acquisition of renewables. A FIT program would provide them with sufficient returns and with certainty of contract award, providing that they meet the FIT criteria.

By contrast, the larger developers generally preferred an RFP process. They said that such processes can produce better results for the buyers by ensuring the pricing is competitive. However, they warned that the winners in an RFP process based primarily on price might not be capable of building the project within the price they had bid. To guard against such outcomes, the developers urged that bidders in an RFP process be carefully screened before being qualified, including requiring them to post a significant deposit which would be forfeit if they are awarded the contract but fail to build the project.[22]

To summarize the results of our survey, the respondents told us clearly that, for comparable renewable energy projects, there is no difference between financing in Atlantic Canada and financing in the rest of Canada or in other jurisdictions. We heard that the most desirable projects from the financier's viewpoint are above $50 million in total finance, and most prefer sizes above that. The survey respondents then added that project development can be more difficult in Atlantic Canada because of the small size of the market and therefore the small number of projects of $50 million or more.

The respondents also commented on and suggested policies that could address these problems. These will be reported in the policy review section, Chapter 7 of this report.

3.3 Review of Relevant Literature

In addition to our interviews with market participants, we looked for available studies that would help us understand the difficulties and opportunities of financing renewable energy projects in Atlantic Canada. We had hoped to find at least one such study with a focus on Atlantic Canada. We could not find a regionally focused study, but we did find some studies dealing with the financing of renewable energy projects. We reviewed these studies to help identify the possible barriers to renewable energy project development, especially to financing such projects. This section reports on the studies we found most relevant and useful.

Renewable electricity generation projects are generally financed on a project finance basis. The overall conditions for finance of renewable electricity generation projects are the same as those for other projects: the project should be economically viable and its risks identifiable and manageable. The literature on finance for renewable energy projects also considers the needs of such projects to find additional sources of revenue (above the electricity market value of their output).

[22] Alternatively, the RFP evaluation process can consider the project development status as a measure of project risk as well as the pricing offered by the Proponent.

The two most helpful studies we found in the literature focused on evaluating the effectiveness of various policies aimed at improving the conditions of finance for renewable projects. One study[23] looked at policies applicable to the stages of project development, from development planning through construction and operation. At each of these stages, policies are available that can reduce risk and therefore the finance rates and overall cost of the project. The study uses a financial model to conclude that a combination of government policy measures can reduce the overall cost of renewable energy projects by up to 30%.

This study specified four different kinds of projects (20 MW onshore wind, 100 MW offshore wind, 1.5 MW solar PV, and 10 and 26 MW biomass) under the policy environments in six jurisdictions: France, Germany, the Netherlands, UK, California and Québec.

Table 1 below summarizes the findings of this report.[24] For several broad categories of policy support, the table shows the range of impacts on levelized unit energy costs, as computed using the financial model for all of the project types in all of the jurisdictions.

Table 1: Impact of Policies on Cost

POLICY AREA	COST REDUCTION IMPACT (%)
Long-term commitment to renewable support	10-30
Risk reduction by removing barriers	5-20
Risk reduction by risk sharing	5-15
Measures to reduce debt costs	5-10
Fiscal measures to increase net returns	2-20
Production support	2-30

Source: David de Jager and Max Rathmann

All of these impacts are attributed to the effect of the policies on the cost of finance. Therefore, the impacts of the different policy types cannot be considered cumulative; the maximum cost impact from a mix of these policies was estimated at 30%.

The study defines and gives examples of the policies it is modeling. Removing barriers means making permitting easier and having transmission available for grid connection when needed. Sharing risk refers to loan guarantees from government or direct project participation from government. Debt measures include low-interest loans direct from government or direct subsidies, typically available for projects which promote the development of new technologies. Fiscal measures range from accelerated depreciation to specific policies to reduce income tax liability (e.g., investment tax credits or production tax credits).

[23] David de Jager and Max Rathmann, "Policy Instrument Design to Reduce Financing Costs in Renewable Energy Projects", IEA Renewable Energy Technology Development, August 2008. http://iea-retd.org/wp-content/uploads/2011/10/Policy_Main-Report.pdf
[24] Ibid., pp. 3-5.

Production support measures enhance revenue during the production period and encompass many of the most effective policies in current use. They include FIT and feed in premium (FIP) programs,[25] direct production payments such as Canada's Wind Power Production Incentive and the ecoENERGY for Renewable Power programs. The study notes that well-designed FIT programs tend to have the greatest impacts on project prices by reducing development risks and financing costs. Such programs would evidence long-term commitments by making the period of the FIT contracts equal to the project's expected life as represented by the term of its financing.

In an effort to assess the reasonableness of these results, in particular the 30% cost reduction, Power Advisory used a financial model to calculate the difference between a typical fully contracted wind project and a similar merchant wind project in the price that would be required for the project to be viable. For the contracted project, there is no basis for distinguishing among the terms and conditions for a contract awarded under a FIT program or an RFP. Therefore, we assume that the financing assumptions wouldn't differ.

This analysis indicated that the price would have to be about 24% higher for a merchant project.[26] This supports the findings of the de Jager and Rathmann study cited above, but suggests that the cost reduction or price required would be 80% of level estimated in this study. However, Power Advisory believes that it would in fact be difficult if not virtually impossible to finance a renewable energy project in Canada on a merchant basis under current market conditions, i.e., low natural gas prices and a focus on quality by lenders.

Another study[27] took a similar approach but analyzed specific cases in specific jurisdictions. The cases were a large onshore wind farm in the US and Spain, offshore wind in Denmark, utility-scale PV in the US and Italy, and a concentrating solar tower in the US. The study started by computing the lifetime unit energy costs for each of these six cases and measured the impact on that cost of the possible renewable energy support policies.

The study looked at the impacts of the policies on finance costs as they would be seen by various classes of finance providers: lenders, mezzanine investors, balance sheet equity investors, and project finance equity investors. Each of these classes expects a different rate of return. As with the study cited above, the analysis used a cash flow financial model to determine the impacts of policies on cost and financial viability.

The study concluded that the three most important determinants of policy effectiveness are

1) The duration of the renewable support, especially the production support. If the debt term ends with the support term, the project must either maintain a much higher rate of

[25] Feed in premium programs pay a premium amount over the market price. Such programs therefore leave the renewable energy project exposed to market price risk, but with additional price support.
[26] The merchant wind project was assumed to have a 60/40 debt-equity ratio, 7% cost of debt, and 13% after tax cost of equity and cumulative debt term of 15 years, with the initial debt having a 5-year term and the second debt issuance having a 10-year term. The contracted wind project was assumed to have a 70/30 debt-equity ratio, 6% cost of debt, and 10% after tax cost of equity and debt term of 18 years.
[27] Uday Varadamjan, David Nelson, Brandon Pierpont, Morgan Hervé-Mignucci, "The Impacts of Policy on the Financing of Renewable Energy Projects: A Case Study Analysis". Climate Policy Initiative, October, 2011.

payment to amortize the debt earlier or take the risk of refinancing part way through the project life.

2) The degree of revenue certainty. A FIT or PPA at a fixed price are preferred to other supports like a FIP.
3) Risk perception. This is the perception of risk in the support policy. Good project management can mitigate other risks; for example, completion risk can be mitigated in the construction contract.

One other study provided some examples of financing relatively small renewable power projects.[28] Most of the policies in this study relate to the specifics of renewable power support in the United States through tax preferences and are not relevant to Canadian circumstances. However, the study also shows how these policies can combine with low-interest loans from government to make renewable power projects economically feasible.

We reviewed briefly several other reports but those described above contributed the results most useful for this project.[29]

3.4 Findings on the RFP Questions

Our findings from our survey of market participants and consideration of the success of renewable developers in Atlantic Canada has led us to some basic conclusions on the three questions posed by the RFP.

1) We find no shortage of debt or equity capital for renewable projects in Atlantic Canada as compared to Canada as a whole. Renewable projects in Atlantic Canada can access both debt and equity markets on the same footing as similar projects in other parts of Canada. Chapters 4 and 5 discuss the financial conditions for renewable projects generally and in Canada.
2) We find no inherently greater risks in Atlantic Canada than in other parts of Canada. However, we do find that the small size of the Atlantic Canada electricity market tends to mean that projects are likely to be smaller, and we find that developers of small projects do face difficulties in raising capital that are not present for large projects. Chapters 6 and 7 deal with financing options for Atlantic Canada projects and with potential policies to address problems with finance, especially for small renewable projects in Atlantic Canada.
3) We find no evidence of greater technical risks in Atlantic Canada than in other parts of Canada for projects using proven technology such as wind turbines or hydroelectric

[28] Mark Bolinger, "Community Wind: Once Again Pushing the Envelope of Project Finance", 2011, LBNL 4193-E

[29] For example, Mark Bolinger, Ryan Wiser, Naum Dargouth, "Preliminary Evaluation of the Impact of the Section 1603Treasury Grant Program on Renewable Energy Deployment in 2009", 2010, Lawrence Berkeley National Laboratory LBNL 3188-E; White Paper: "Renewable Energy Project Finance in the U. S.", 2010, Mintz Levin; International Conference for Renewable Energies, "Mobilizing Finance for Renewable Energies", 2007, Thematic Background Paper for conference Renewable Power Policy and the Cost of Capital, UN Environmental Program, Sustainable Energy Finance Initiatives; Dermot Duncan, "Project Financing Electricity Generation Projects in NSW with a Specific Focus on the Externalities to Renewable Generation, Dec. 2010, Crisp Legal.

generation. We note the interest in development of new technologies, specifically tidal power, but did not find evidence to indicate that its development in Atlantic Canada is more difficult than would be development of a similarly new technology elsewhere in Canada.

4 Review of Factors Affecting Cost of Capital

4.1 Introduction

An investors' cost of capital represents the minimum return or hurdle rate an investor needs to achieve for investing in the project, and this hurdle rate is influenced by what returns the investor expects or is able to achieve on investment in other projects with similar risk profiles.

The general framework for estimating the appropriate cost of capital for a company is based on an economic theory called the capital asset pricing model (CAPM), which is considered "the backbone of modern price theory for financial markets". [30, 31] CAPM begins with a risk free rate and provides a theoretical framework for estimating the appropriate return for the specific risk factors by observing the returns for other similar securities. In practice, investors start with the appropriate risk free or reference base rate (for debt investors) and estimate a premium above the base rate, using a combination of theory and judgment, that is necessary to compensate the investor for the additional risks above the risk free rate, as shown below.

Table 2: Components of the Capital Asset Pricing Model

Cost of Equity and Cost of Debt[32]	
Cost = Risk Free Rate (equity) or Reference Base Rate (debt)[33] plus risk factors:	
+ Impact of Project Specific Factors + Impact of Size and Liquidity + Impact of Other terms + Impact of General market conditions	For Debt capital, the total impact of these factors is known as the credit spread. For Equity, the total impact of these factors is known as the risk component of the cost of equity.

Source: Power Advisory

While the risk free rate can vary significantly, changes in the risk free rate are not within the developers' control (see Section 4.2). Experienced project developers focus on minimizing the credit spread, as renewable projects are predominantly financed with debt capital (70% to 80% of total capital).[34] Reducing the cost of debt will reduce the cost of equity for the project, which will in turn reduce the cost of financing the project and the minimum power price required to keep the

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[30] Merkowitz, Miller and Sharpe were jointly awarded a Nobel Peace Prize in Economic Sciences in 1990 for their pioneering work in the development of the theory of portfolio choice, CAPM, and other fundamental contributions to the theory of corporate finance.
[31] "The Prize in Economics 1990 - Press Release". Nobelprize.org. 12 Dec 2011 http://www.nobelprize.org/nobel_prizes/economics/laureates/1990/press.html
[32] While each of the following risk factors will impact the pricing for both debt and equity, the impact will not necessarily be equal.
[33] The appropriate reference base rate for debt capital depends on several factors, such as the term and the repayment schedule of the loan.
[34] Less mature technologies, such as tidal, may have difficulty obtaining debt financing. Biomass projects will typically raise a lower amount of debt relative to other renewable technologies because of higher perceived operational risks, including the risk of obtaining a long-term fuel supply and the risk that project revenues become disconnected to project costs given swings in biomass costs.

project economic.[35] The components which influence the credit spread or risk component are detailed in Section 4.3.

This discussion of finance conditions for renewable generation facilities is in the context of the project finance approach which is used for most renewable generation facilities. Whatever mode of finance is used, the projects still must meet the rate of return criteria described here.

4.2 The Risk-free or Base Rate

The risk-free rate of return is a theoretical rate of return for an investment with zero risk of default in the region where the asset resides and forms the underlying basis for pricing the cost of equity and debt capital for a project since an investor will need to be compensated for each additional risk factor layered onto the investment.[36]

A complex set of factors governs the movement of interest rates, including monetary and fiscal policy. The rate determined at the federal and global level and fluctuations in the risk-free rate are largely outside of the control of the project developer. As shown in the graph below, the yield of the benchmark 10-year Government of Canada (GOC) bond has fluctuated from a high of 5.8% to approximately 2.0% between March 2002 and November 2011. During this time period, reference bond yields have been very volatile, which would have increased the cost of capital for renewable energy projects as prudent developers will leave a buffer to account for market changes in the key components of the cost of capital to improve the likelihood that the project will remain economically viable at financial close.[37]

[35] The cost of equity for a project should exceed the cost of debt for the project as debt receives a return on and of its capital in priority to equity capital, and has prior claim in the event of default. The effective cost of debt is also cheaper because of the deductibility of interest expense.

[36] In Canada, the yield from the 10-year government of Canada bond is commonly used as a proxy for the risk free rate for the purposes of estimating the cost of equity.

[37] Large developers are not as sensitive to the impact of volatility in base rates (and the other factors impacting pricing detailed in this section) as those developers have the ability to take a longer-term view of the financing markets. These developers can ***choose*** to finance the project on balance sheet on the assumption that financing rates will improve over time, at which point the developer can choose to replace corporate funding with project financing. However, large developers which choose to rely on corporate level or balance sheet financing to fund projects are more susceptible to changes in market conditions once their corporate borrowing capacity is reached. Calpine Corp. and Babcock & Brown are examples of large-scale bankruptcies for infrastructure companies with high levels of corporate level debt. The current instability in the European banking sector means that many of the European power developers are re-examining their corporate-level credit capacities which could curtail their ability to balance sheet finance going forward. See Chapter 5 for a more detailed description of the capital markets.

Figure 3: Canadian 10-year GOC Bond Yield

Data Source: Bloomberg

For debt capital, the reference rate varies according to the type of debt (floating rate or fixed rate), term and amortization schedule. While only a graph of the 10-year GOC bond yield was shown, the decline in yields and the high volatility (particularly since 2008) would be consistent across all reference rates.

4.3 Review of Key Risks that Affect Project Financing

The preceding discussion reviewed the economic and financial market fundamentals that determine the cost of capital for projects. To evaluate the challenges in the financing of renewable energy projects in Atlantic Canada it is important to understand project risks that will be considered by lenders and investors and the risks that are borne by developers to get their projects to a point where they can be financed. The risks considered by lenders and investors affect the terms under which IPPs will be able to secure financing, with riskier projects incurring higher costs of capital and projects with risks that are too great in the eyes of lenders and investors unable to attract the necessary capital.

4.3.1 Project Related Risks

This section reviews the project-related risks that affect the renewable project's cost of capital or affect its availability of capital. Six fundamental project-related risks affect the capital costs for projects:

1) technology risk, focusing in particular on the degree to which the technology is immature and doesn't have significant commercial operating experience for the proposed application;
2) operating risks including the operating performance of the equipment with respect to the energy conversion efficiency (e.g., power curve for wind) and fixed and variable operating and maintenance costs;
3) market risks, which consider the revenue uncertainty of the value of the project output;
4) resource availability risks, which consider the underlying variability of the resource and the potential for measurement error when estimating the resource;
5) construction risks that are borne by the project proponent rather than allocated to the firm procuring equipment for and constructing the project; and
6) market access risks including the potential for transmission constraints.

Each of these risks and the manner in which they affect the cost of capital is reviewed further below.

Technology and Operating Risks

Technology and operating risks are directly related. To more clearly distinguish between the factors that contribute to these risks we discuss them separately in this section. However, there is considerable overlap. Lenders are very reluctant to consider projects that have significant technology risk. At a minimum, they will look to the equipment vendor to provide performance guarantees and will want to ensure that the equipment vendor has sufficient financial capability to deliver on these commitments.[38] For example, for wind projects the equipment vendor typically provides a power curve guarantee which guarantees the project output levels at measured wind speeds.[39]

Many equipment vendors (virtually all wind turbine suppliers) offer service and maintenance agreements for the initial years of project operation, e.g., two to five years. For a set fee the

[38] The number of notable case studies where the supplier did not have such financial stability includes Clipper Wind Power which developed a 2.5 MW variable speed wind turbine and was led by seasoned wind industry professionals and AAER Inc., a Quebec wind turbine manufacturer. Clipper Wind Power's 2.5 MW Liberty Wind Turbines developed issues with the gear box and blades which resulted in a dramatic slowdown in orders and ultimately caused United Technologies to take a 49.5% interest in the Company and eventually acquire the entire company. AAER Inc. suffered from slow sales and eventually was acquired by Pioneer Power Solutions who discontinued the business.

[39] Specifically, the project owner receives liquidated damages to the degree that the project output is less than the guarantee. However, these liquidated damages are capped (often to 10% of the contract amount) and the project owner must demonstrate that the project output is less than promised. This requires a formal test, the cost of which would be paid by the project owner if it shows that the project output is consistent with the guarantee.

equipment vendor agrees to provide major maintenance services. This significantly reduces project operating risks by fixing maintenance costs according to the contract and ensuring that the maintenance is performed according to manufacturer's recommendations. In addition, it reduces the potential for disconnects between the warranty provisions in equipment supply contracts and maintenance contracts given that effectively one party will be providing the two services.

Another technology/operating risk is the equipment availability. For mature technologies this is a relatively minor risk, particularly for wind projects which install a number of wind turbines which effectively diversifies this risk. Hydroelectric turbines are also a mature technology with low performance risks. Once again, lenders will be reluctant to lend to projects that employ new technologies or equipment venders with limited operating experience.[40]

Atlantic Canada has a tidal resource that both Nova Scotia and New Brunswick want to develop. In Nova Scotia, two tidal array projects have received COMFIT contracts. This is a very new technology and these projects would represent its early deployment. An early application of this technology in Nova Scotia was removed from service after several months of operation. Lenders can be expected to perceive the technology risks of these projects to be very high.

A technology risk that can affect the cost of capital is that the useful life of the equipment could be less than anticipated, particularly if it were less than the tenor of the debt and the debt amortization period. A related risk is that required capital additions could be much higher than anticipated.

Market Risks

In the current financing environment lenders and investors are reluctant to finance projects which don't have a long-term power purchase agreement (PPA) which provides revenue certainty for project output. Without a PPA, the project proponent faces the risks of uncertain future revenues. The interconnected provinces of Atlantic Canada have wholesale market access which allows project proponents to wheel power to adjacent markets, but limited retail market access.[41] Therefore, independent power producers must be awarded a PPA or wheel power to New England. Ideally, the term of the PPA is as long as the debt term plus an additional two years or more, i.e., a two year or more tail that provides revenue certainty beyond the term of the debt and could allow the debt to be rescheduled if necessary. PPAs typically have durations of 20 to 25 years for wind and most renewable energy technologies and up to 40 years for hydroelectric projects.

[40] The introduction of new power generation technologies will frequently require government support to move from pilot-scale to utility-scale projects. In the US, the Department of Energy provided a Loan Guarantee Program (Section 1705), which facilitated the introduction of solar thermal generation projects in the U.S. Indeed, with the expiry of the program many of these solar thermal generation projects have been cancelled or are in the process of being converted into solar PV projects, which are better understood by the financial markets. Following the example in the US, Atlantic Provinces could encourage the development of innovative technologies that are well suited to the region (e.g., tidal technology) by providing support through a loan guarantee.

[41] Nova Scotia allows renewable project developers to have direct retail access.

Resource Availability Risk

Resource availability risk considers the underlying variability of the resource and the potential for measurement error when estimating the resource. This risk is most significant for wind projects given that relatively small variations in average wind speeds can have significant impacts on project output.[42] For example, wind resource forecasts rely on models which estimate a power output for each turbine at specific heights and locations within the project site, based on wind measurements received from the met towers which are in different locations and heights. For wind projects, resource availability risk is evaluated and mitigated in project financings by engaging an independent meteorological expert to review the wind resource studies and calculate the output that the project is likely to achieve or exceed at different probability levels, e.g., P50, P90, and P99.[43] For example, lenders will typically assess the adequacy of debt service coverage ratios (DSCR) at less favourable (more stringent) project output probabilities such as P90 and may require that the DSCR be at least 1.2 under the P90 conditions.[44]

For hydroelectric projects, lenders would expect good history of hydrological data, again converted into probabilities for different exceedance levels.

For biomass projects, the resource availability risk focuses on the ability of the project to secure sufficient long-term biomass supply at a consistent quantity and quality to ensure production. If the biomass is waste from another operation, particularly forestry, the renewable electricity generation project is vulnerable to loss of resource if the operation is shut down, even if it is a temporary shutdown. If the biomass is from other resources, the risk is the exhaustion of the resource in nearby locations and consequently higher transportation costs.

Construction Risks

Many IPPs rely on Engineering Procurement and Construction (EPC) contracts to manage construction risks. Under EPC contracts the IPP is able to allocate many of the construction risks and equipment cost risks to the firm providing the services. However, the terms and form of EPC contracts vary. Under a fully reimbursable EPC, the IPP maintains flexibility and bears most of the procurement and construction risk as costs are largely a pass through. Under a Lump Sum EPC, these risks are largely borne by the EPC firm, but the IPP pays a premium for this service and under some conditions (periods of significant expected cost escalation) such a contract is difficult to get. As implied, IPPs typically don't have a comprehensive EPC and there are often multiple contractors, with one party assembling and erecting the wind turbines and another the balance of plant. Therefore, there is likely to be some residual risk to the degree that the contracts don't link up. Finally, smaller community projects are unlikely to be able to secure such contracts given the size of the project, limited project budget, and limited interest of

[42] A rule of thumb is that a doubling of the average wind speed results in eight times more output.
[43] For example, the project output at P90 is the output that the project will achieve or exceed with a 90% probability. The output levels for different exceedance levels (e.g., P50 or P90) typically increase when assessed over a longer period of time (e.g., at P90 the annual output for a turbine may be 5,000 MWh and 5,250 MWh over 20 years.)
[44] DSCR are the annual Earnings Before Interest Taxes Depreciation and Amortization (EBITDA) divided by the annual debt service (interest and principal payments).

engineering and construction firms in performing the detailed work required to firm up pricing. However, unless the project site is difficult to access or requires significant groundwork, wind and solar renewable projects are generally easier to construct as the less predictable balance of plant costs represents a smaller proportion of the total construction budget (compared to traditional thermal projects).

Market Access Risks

All the Atlantic Canada provinces, except Newfoundland and Labrador (and Newfoundland isn't currently directly connected to the Eastern Interconnect), offer wholesale market access under Open Access Transmission Tariffs. The most significant market access risks for renewable IPP projects in Atlantic Canada are the potential for transmission constraints that cause the project to be constrained down or off. This risk increases as the penetration of intermittent renewable energy projects in these markets increases. [45] A critical determinant of the magnitude of this risk is the transmission service for which the IPP contracts and how this risk is addressed in the PPA. When a generator is provided with firm transmission service, curtailment risk is typically more limited, but this can require that the transmission network be reinforced, most likely at the cost of all transmission customers. If the IPP elects non-firm service it would be at greater risk of being curtailed if there were transmission congestion. A critical issue in Atlantic Canada is that the rules for managing transmission congestion (who would be curtailed and for how long) are not well developed. Furthermore, to date there have been relatively limited amounts of intermittent generation curtailed. Given both these factors it is difficult for IPPs to assess this risk.

Another market access risk that IPPs have to manage is the uncertainty associated with interconnection costs that they will have to bear. Most Generation Interconnection Procedures provide for a series of increasingly rigorous cost estimates. Typically, IPPs are awarded contracts before the final more detailed cost estimates are completed and there is risk that these interconnection costs estimates increase after the contract price has been established.

Development and Pre-Financial Close risks

A number of development related risks are addressed prior to project achieving financial close and therefore would not affect the cost or availability of capital. These risks typically determine project attrition rates. This includes environmental permitting risks and various financial and economic risks.

Financial and Economic Risks

IPPs also face financing risks associated with changes in financial market conditions during the period from finalization and acceptance of a contract pricing proposal until the project is financed. These financial and economic risks include foreign exchange rate variability where significant changes in foreign exchange rates (e.g., depreciation of the Canadian dollar) can increase the effective cost of equipment contracts that are priced in a foreign currency (US$ or Euros). This risk is mitigated to the degree that projects in Atlantic Canada purchase generation

[45] This risk is more of a concern in Nova Scotia given its transmission infrastructure and the location of considerable amounts of generation on Cape Breton with its major load centre in the metro Halifax area.

technologies with significant Canadian content or offering appropriate price escalators. Another financial risk is significant increases in interest rates and investor return expectations after proposal pricing has been finalized such as occurred in Nova Scotia after its 2007 Renewable Energy RFP. As discussed, these contributed to delays in the development of a number of projects and caused the ownership of several projects to change.

4.4 Limited Availability of Lenders and Equity Investors for Smaller Projects

In discussions with debt and equity capital providers, there was a common comment that it is difficult to provide non-recourse asset level financing for projects less than $50 million in size.

4.4.1 Fixed Costs of Due Diligence and Structuring

The due diligence and structuring costs for a typical renewable power project financing can easily reach $1 to $2 million in total transaction costs, and a significant portion of the transaction costs is fixed regardless of the size of the project. Examples of these fixed costs include the

- legal costs of the investor and the debt provider;
- independent engineer's report to review the initial cost and performance estimates for the project and review the ongoing capital draw-down requests for the lenders;
- resource assessment;
- environmental review;
- interconnection review; and
- financing and advisory fees.[46]

Projects that do not have the requisite due diligence will be unable to obtain project financing, and would require additional credit support from a third party source (equity provider, other assets or the government) to finance the project.

4.4.2 Greater Profitability of Larger Projects

Most of the capital providers with renewable project financing expertise are large institutions and need to pursue larger projects to provide a meaningful impact on financial results. Smaller financial institutions would generally not be capable of executing enough renewable power projects to develop an appropriate level of expertise. In speaking to financial institutions, project financiers typically have a minimum size threshold of $50 million for pre-existing relationships with a $75 to $100 million minimum threshold for most projects.

4.4.3 Developers Pursuing Smaller Projects Typically Lack Experience

The size of project the developers are pursuing is generally a good indicator of the level of experience a developer has, as an experienced developer would pursue larger opportunities as the pursuit costs are largely fixed and the economic payback to the developer is greater. Smaller

[46] While financing and advisory fees vary with the size of the project, the financing and advisory fees as a percentage of capital increase significantly for smaller projects to cover the fixed internal costs of providing these services.

projects have difficulty attracting capital and will suffer from lower returns unless the PPA price offers a sufficiently high premium over the PPA price for larger "utility-scale" projects.

4.4.4 General Illiquidity of Smaller Transaction Sizes

Capital providers that may not hold the investment to the end of its term place a premium on the ability to sell and trade the investment. Transactions below a certain size will also limit the universe of potential buyers for the investment and as a result increase pricing.[47]

4.5 Process for Administering RFPs

Pursuing power project development is inherently a risky process, and project developers strongly prefer processes which are quick and clear and thus reduce the opportunities for a proposal to be rejected.[48]

4.5.1 Insufficient Certainty for Project Developers

The RFP should have transparent criteria for the evaluation and selection of proposals and ensure that the process has a level playing field for all participants.

4.5.2 Length of Time Pricing Proposal Needs to be Open

Reducing the amount of time a pricing proposal needs to be open reduces attrition because the project economics are less exposed to market risk (e.g., changes in construction and financing costs). Therefore, it is desirable to reduce the period between when bids are submitted and contracts are awarded.[49] In addition the cost of maintaining the pricing in a RFP response is a direct function of the "firmness" of the pricing proposal and the amount of time the pricing proposal needs to be firm. As the cost for maintaining the pricing proposal is generally "at-risk" capital for the project developer, the project developers are keen to minimize this amount. Having larger amounts of "at-risk" capital creates a bias for larger projects and larger developers who can absorb the increased costs or increases the risks of project defaults by small developers.

4.6 Power Purchase Agreement Terms Leading to Higher Attrition Rates

Lenders pay particular attention to the details of the following terms. While the PPA should be designed to ensure and incentivize the owner of the project to operate the facilities at a high performance level, setting the performance levels at an inappropriately high or onerous standard will increase the risk of default, or potentially make it impossible for the project to obtain financing. Examples of these terms are discussed below.

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[47] In the 2011 Ibbotson Risk Premia Over Time Report, which evaluates the cost of equity in the US over time, Ibbotson estimated an equity investor would need a 4.48% premium to invest in a company with a market capitalization <$235 million (10th decile), versus a company with a market capitalization between $773 and $1.2 billion (7th decile).

[48] Every small developer we spoke to preferred a FIT program, where available.

[49] Power Advisory is seeking to do this in Nova Scotia by requiring Proponents to submit bids and accept the PPA that is offered rather than allowing negotiation of the PPA after contract award. This also ensures that all proponents are bidding to the same PPA and ensures the same risk allocation across projects.

4.6.1 Termination Provisions for Non-Performance

Lenders pay close attention to any termination provisions as the termination of the PPA will cause the project to enter default, and likely into a situation with a low prospect of recovery as the value of the project is substantially determined by the value of the PPA. Given the resource variability for most forms of generation in the renewables sector, termination provisions relating to a level of power generation are generally set at a threshold which recognizes the resource variability as the operator has less control over the actual power produced (unlike an operator of a thermal facility). This is particularly relevant for earlier-stage technologies such as tidal power.

4.6.2 Appropriate Pricing Escalators (Initial and Ongoing)

The risk of project attrition for PPAs without initial pricing escalators increases with the length of time between the PPA award and the closing of financing. During this period, construction and financing costs can continue to fluctuate, and in periods of extreme volatility, a sharp increase in the construction and /or financing costs without a change in the PPA price could cause the projects to become uneconomic to pursue.[50] However, allowing contract prices to escalate prior to commercial operation increases risks to the buyer and suppliers are able to mitigate these risks by contracting with the equipment manufacturer and EPC firms.

In addition, having a pricing escalator for the PPA which tracks the costs of operating the facility is strongly preferred. For debt providers, this can allow the debt service coverage ratios to increase (rather than decrease) as the remaining PPA life (economic value) diminishes. However, debt service coverage ratios will only increase to the degree that the proportion of the project price that escalates with inflation is greater than the proportion of project costs escalating with inflation. For equity investors, an inflation protected investment is highly sought after.

4.6.3 Pricing Penalties

Capital providers generally prefer incentive-based performance mechanisms to pricing penalties to encourage performance levels. Introducing pricing penalties can erode the financial strength of the project when the project is already underperforming, thus increasing the risk of default and potentially causing the project to be unfinanceable if the risk of default is considered too high. Therefore, a critical issue is at what performance level such penalties take effect.

[50] Québec Wind RFPs are examples of projects needing additional economic incentives introduced after the initial PPA award in order to finance the projects.

5 Review of Current Capital Market Conditions

5.1 Atlantic Canada vs. Other Jurisdictions

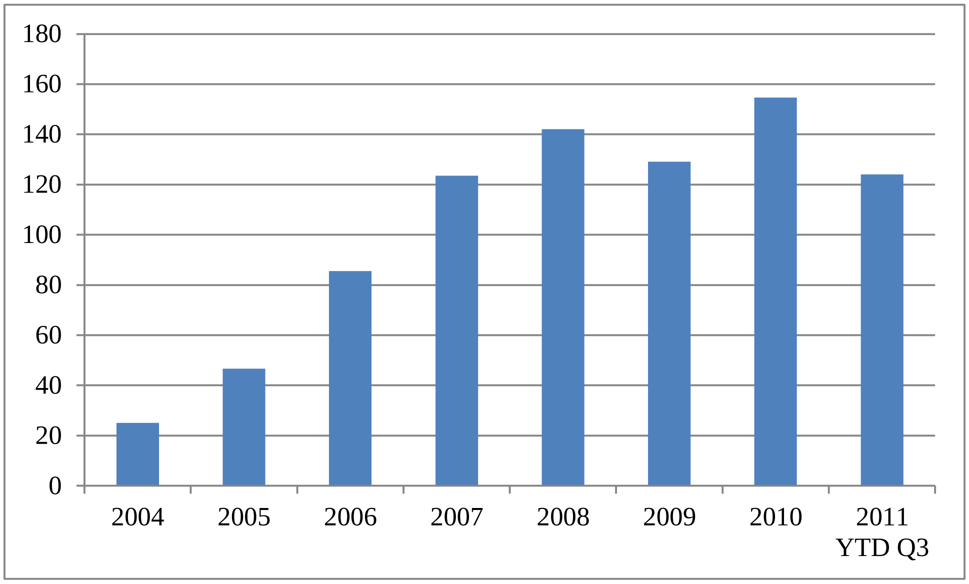
To evaluate the current capital market conditions for funding the construction of renewable power projects in Atlantic Canada, it is important to examine capital market conditions across Canada as much of the capital to build renewable power projects in Atlantic Canada comes from national and international investors.[51] While smaller projects, such as community-based projects, can be wholly funded by local capital or are unlikely to attract national or international capital, local investors would look to the risk and return profile for renewable projects located elsewhere in Canada as a benchmark.[52] However, the financing of smaller projects is more insulated from broader financial market conditions. The financing for these projects is likely to be influenced more by the availability of specific programs and policies that support their development and financing.

Our discussions with renewable sector investors made clear that the issues faced by projects in Atlantic Canada were similar to the issues faced in developing projects in other jurisdictions and that projects in Atlantic Canada did not require any adjustment in approach or debt or equity pricing. As such, this section focuses on the capital market conditions within Canada generally since we believe that cost and availability of capital for projects in Atlantic Canada is no different from that for other renewable projects of similar size located elsewhere in Canada.

Global investment in clean energy projects remains high as shown in Figure **4**. International investors continue to look favourably at investing in Canada due to the relative stability of the economy and relatively high growth rates. For example, Canada's forecast for GDP growth remained relatively robust at 2.3% in 2011 (compared to 1.4% for the G10 countries), and is expected to slow but remain relatively strong at 2.0% in 2012 (compared to 1.2% for the G10 countries).[53] Furthermore, the Canadian economy isn't subject to the same debt overhang as that plaguing the European Union and the U.S. which adds considerable uncertainty to their capital markets.

[51] Even projects wholly-owned by NSPI, a company located in Atlantic Canada, need to be evaluated in the context of the Canadian capital markets, as the majority of NSPI's debt and equity capital is from investors domiciled across Canada.
[52] Subject to a size-based premium, as discussed in the cost of capital Chapter 4.
[53] Bloomberg composite of economists, December 2011.

Figure 4: Global New Investment in Clean Energy (US$ Billions)[54]



Data source: Bloomberg

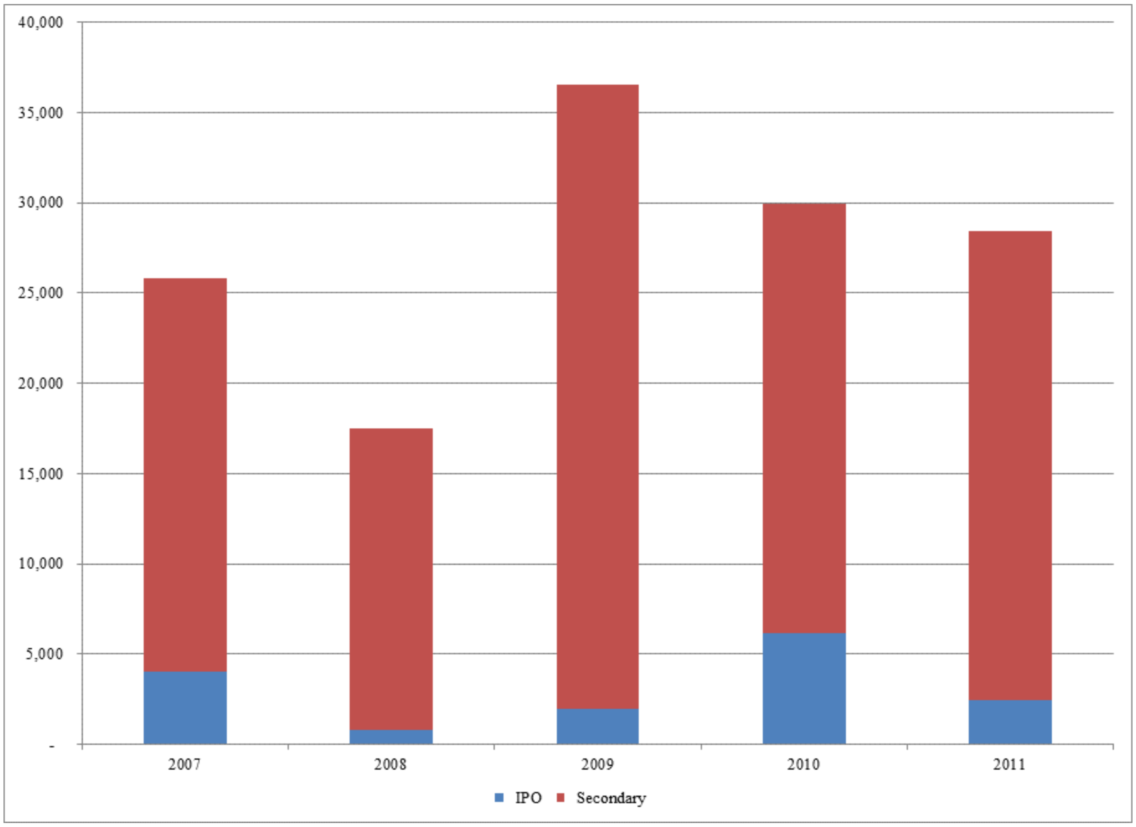
5.2 Equity Capital Markets

5.2.1 Availability of Capital

Ability to raise capital for safe, high-quality investments continues to be strong, while the continuing volatility in the equity markets makes raising capital for new ventures difficult. As shown in Figure 5, while the total amount of equity capital raised in Canada has recovered, raising capital for new companies (initial public offerings) remains a challenge.

[54] Source: Bloomberg New Energy Finance

Figure 5: Equity Capital Raised in Canada, Initial and Secondary Sales ('000s)



Data source: Bloomberg

For established project developers, raising capital has been relatively straightforward. This is demonstrated by the ability of Capstone Infrastructure , Innergex Renewable Energy , and Algonquin Power & Utilities Corp., three electricity generation and infrastructure companies with significant renewable project holdings, to easily raise equity capital on a bought-deal basis in 2011 to support acquisitions.[55] In addition, smaller project developers, which are generally thinly-capitalized or have a limited track record, got bigger in order to improve access to the capital markets and have the financial capacity (or buffer) to raise capital when it is advantageous to do so. Examples in 2011 include developers merging with other developers (Magma Energy's acquisition of Plutonic Power), with their affiliated operating portfolio (Innergex Renewable and Innergex Income Fund), or with a financial sponsor (such as Shear Wind with Inveravante).

Unlisted infrastructure sector funds have also invested in Atlantic Canada, and many infrastructure funds are looking for investments.[56] Thirty-eight infrastructure funds closed in 2011, raising a combined $16 billion and Prequin estimates that $34.3 billion is available for

[55] In a bought deal situation, the dealer will fully underwrite the offering. Therefore, the dealer takes the risk of what it will be able to sell shares for. A bought deal indicates that the dealer is highly confident of its ability to sell the shares without the benefit of pre-marketing intelligence. This is in contrast to a marketed deal where the dealer acts on a best-efforts basis.

[56] Firelight Infrastructure Partners has invested in Amherst wind farm and the Dalhousie Mountain wind energy project. Firelight Infrastructure Partners is a JV between OP Trust and Dundee Real Estate Asset Management with a mandate to invest in renewable energy projects across Canada.

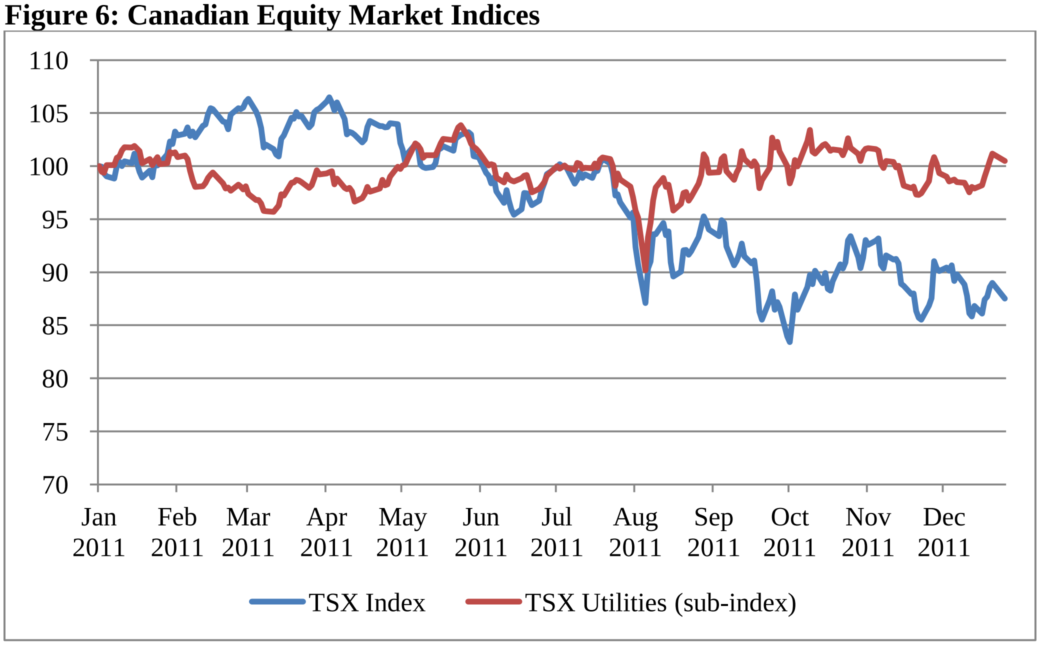
infrastructure investments by unlisted infrastructure investors that are targeting North America.[57,58]

5.2.2 Cost of Capital

The TSX utility (sub index) closed 2011 flat to 2010, while the broader TSX index closed down by 12%. The continuing volatility in the broader equity markets has caused investors to focus on safe, cash flow producing investments.

During 2011, Canadian publicly traded power companies with significant renewable power assets had a cost of equity of approximately 9.6% to 11.7%.[59] These publicly traded companies are a combination of operating and development assets. The cost of equity range is consistent with recent equity return expectations for operational assets which is below 10%, and for development assets which is generally in the mid-teens.[60] These observations are further supported by discussions with other infrastructure sector professionals regarding current valuation levels and the degree of competition for safe infrastructure investments, such as renewable energy projects which are underpinned with long-term power purchase agreements with counterparties with strong credit.

Figure 6: Canadian Equity Market Indices



Data source: Bloomberg

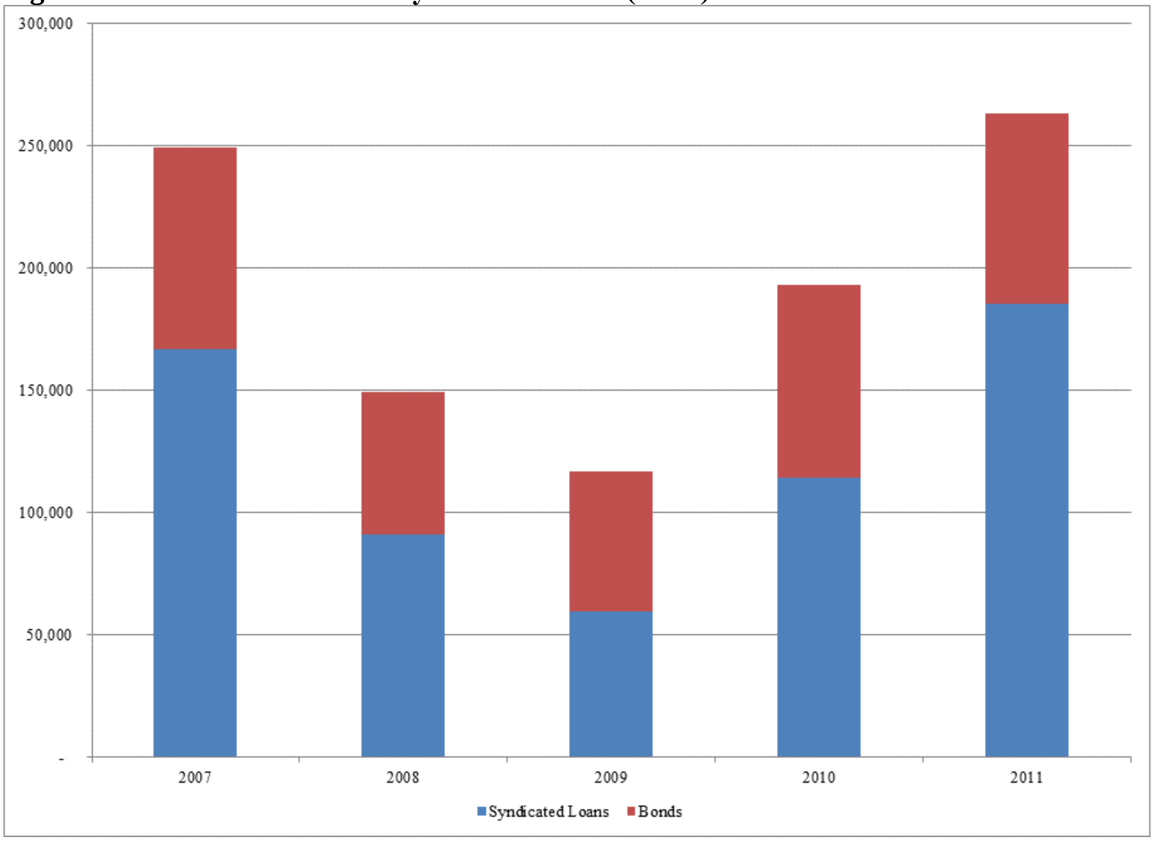
[57] Prequin quarterly infrastructure review, Q3 2011.
[58] "Infrastructure Ends 2011 on Fundraising High" (Press release). Prequin. January 4, 2012. http://www.preqin.com/docs/press/Infrastructure_2011.pdf
[59] The cost of equity capital for Northland, Capstone, Innergex, Brookfield, Algonquin, and TransAlta were estimated using CAPM on November 2, 2011. Source: Bloomberg
[60] Return expectations will vary according to the specifics of the assets. Return expectations will generally be higher for smaller projects.

5.3 Debt Capital Markets

5.3.1 Availability of Capital

Significant debt capital is available in the Canadian market and as shown in Figure 7 below, the value of bond and syndicated loan transactions completed in Canada in 2011 was at its highest level in the past five years and more than double the amount of debt capital raised in 2009.

Figure 7: Canadian Bonds and Syndicated Loans ('000s)



Data source: Bloomberg

For renewable project developers, there are two main types of project financing available: (i) a mini-perm structure which is a form of bridge financing which requires a refinancing with a term loan or a bond no later than five years post project completion; or (ii) a permanent term loan which provides a locked-in rate over the entire term of the loan.[61, 62] The choice between option (i) or (ii) depends on the depth of the each market at a given point in time, and also on the developers' assessment of the refinancing risk as the project will book a gain or loss on the difference between the assumed and actual refinancing spread at the time of refinancing.[63]

[61] The refinancing period for the mini-perm will vary but is frequently for a period no more than five years.
[62] In a mini-perm facility the cost of the bridge loan increases each year post completion.
[63] The mini-perm market is much deeper in terms of the size of market and the number of participants. However, capital providers compete for quality projects and savvy developers continually evaluate and choose between all their sources of capital for each project.

Under a permanent term loan structure, the entire repayment schedule (principal and interest) is specified over the entire term (frequently 18-years post COD for a 20-year PPA). In a mini-perm structure, the amortization and frequently the base rate portion of the interest payment is set over the full term (the same 18-years post COD as in the term loan), and the developer must refinance the mini-perm with a new term loan at up to five years post project completion. If credit spread at the time of refinancing is lower than the assumption used to set the original mini-perm amortization schedule, then the developer will realize a release of equity; conversely if the credit spread is higher than expected, then the developers' dividends from the project will be reduced. A mini-perm structure is a bet by the developer than the credit spread will be below the assumed spread before the end of the mini-perm facility, and that the weighted-average interest rate is below what would otherwise be available under a permanent term loan structure.

Canadian and US banks will generally offer only a mini-perm structure, while life insurance companies and pensions funds offer fixed rate project debt financing over the entire term of the financing and may also decide to invest equity capital as well. Japanese and European banks traditionally have offered both mini-perm and long-term fixed rate project financing structures. While Japanese banks are still active in the Canadian market, many European banks have significantly curtailed their activities in Canada.[64, 65] As European banks were significant lenders to renewable energy projects globally, there should be an impact from these lenders leaving the market, but so far, there remains strong demand and available capital from the other industry participants.

Given the continuing volatility in Europe it is difficult to determine the number of active power project financing firms in Canada. However, at least 30 different institutions have successfully provided project financing debt to Canadian renewable projects since 2010.[66]

These specialized project finance lenders will not lend to smaller community projects as it would not meet their minimum size threshold ($30 to $50 million). For these lenders to lend to a

[64] Many of the prominent European lenders to the renewable sector are based in or have significant exposure to countries which have received or are considered at-risk of requiring a bail-out which would cause the value of their debt to be written down. The European Banking Authority in its latest round of stress tests dated December 8, 2011, estimates that the European banks have a shortfall of €115 billion including sovereign capital buffer. Many European banks have shut down or ceased their Canadian lending activities. At times, the decision to shut down has come abruptly, even while in the late stages of a transaction.

[65] Basel III, which will be phased in from January 1, 2013 to January 1, 2019, provides for a set of comprehensive reform measures designed to strengthen the regulation, supervision and risk management of the banking sector. The regulations are generally expected to increase the cost of financing as banks will have higher capital requirements (and thus have less ability to lend or generate revenue on the same capital base). The regulations also encourage banks to have a closer match between the maturities of a bank's assets and liabilities. As the majority of the banks' liabilities are on a short-term basis, it's believed that a bank's capacity to offer long-term project financings will be become more limited and result in more mini-perm financings.

[66] This is based on the review of the public disclosure for sixteen renewable power projects with financial close announced in 2010 and 2011. Canadian and US Banks: CIBC, BMO, TD, BNS, National Bank, Union Bank; Life insurance companies: Manulife and the other major life insurance companies; Funds and Pension Funds: All major Canadian pension funds, such as Caisse de Depot, Stonebridge; Japanese Banks: Bank of Tokyo, Sumitomo, Mizuho, SMBC; European Banks: Deutsche Bank, KFW, Landesbank, Siemens, Naxitis, Rabobank, BLB, Bilbao, Dexia, Nord L/B, Caixanova, and WestLB.

community project, the community projects would need to be aggregated to meet the minimum size threshold.[67]

5.3.2 Cost of Capital

The current all-in cost of debt for A and BBB rated 10-year loans is at a 5-year low, despite credit spreads which have remained in line with credits spreads from 2009/2010.[68] The continued decline in base rates has caused the decline in financing costs as pricing and other debt terms have largely remained the same:

- Debt / capitalization: ~75%[69]
- Amortization term: 18-years (assuming a 20-year PPA)
- DSCR (minimum): 1.20x – 1.25x
- Short-Term Rates: ~1.5% (6 month Canadian LIBOR)[70]
- Swapped Rates: ~3.0%[71]
- Credit Spread: 225 - 250 bps[72]
- All-in Rates: 5.25% to 5.50%

Base rates are expected to remain low as the Bank of Canada has kept and is expected to continue to keep overnight lending rates at 1.0% until the end of 2012.[73] Going forward, there should be upward pressure on credit spreads for renewable projects as many European renewable power sector lenders have exited the Canadian markets pending the resolution of the sovereign debt situation in Europe.[74] So far we understand that credit spreads for renewable projects in Canada

[67] There have been government sponsored programs, such as PEI Energy Savings Bonds, which were designed to allow Islanders to invest in the Eastern Kings Wind Farm. However, unlike the project financings discussed in this report where debt investors have recourse only to the project assets, the PEI Energy Savings Bonds are fully guaranteed by the Province of PEI and thus the repayment risk for the debt investors is not dependent on the performance of the wind farm and thus avoids the requirement for due diligence and structuring costs on the part of the investors. Approximately $6 to $7 million was raised under this program.

[68] A credit spread is the difference in the all-in interest rate and the corresponding rate on the “risk-less” benchmark security. The credit spread is primarily meant to compensate the investor for the incremental risk of default above and beyond the default risk in the benchmark security. For floating-rate debt, the credit spread may be over a benchmark interest rate such as LIBOR (London Interbank Offered Rate), Bankers’ Acceptances or Prime rates. For fixed rate debt, the credit spread would be over the yield for a Bank of Canada bond (treasury security) with the same term.

[69] Subject to achieving the debt service coverage ratios (DSCRs) indicated.

[70] This will vary depending on reference base rate used by the bank

[71] The lender will likely require a portion of the base rate to be fixed over the amortization period of the loan. The swapped rate is the rate the project will pay the swap provider in exchange for receiving the floating rate over the period. The actual swap rate will depend on the credit quality of the project and the actual cash flow profile of the project.

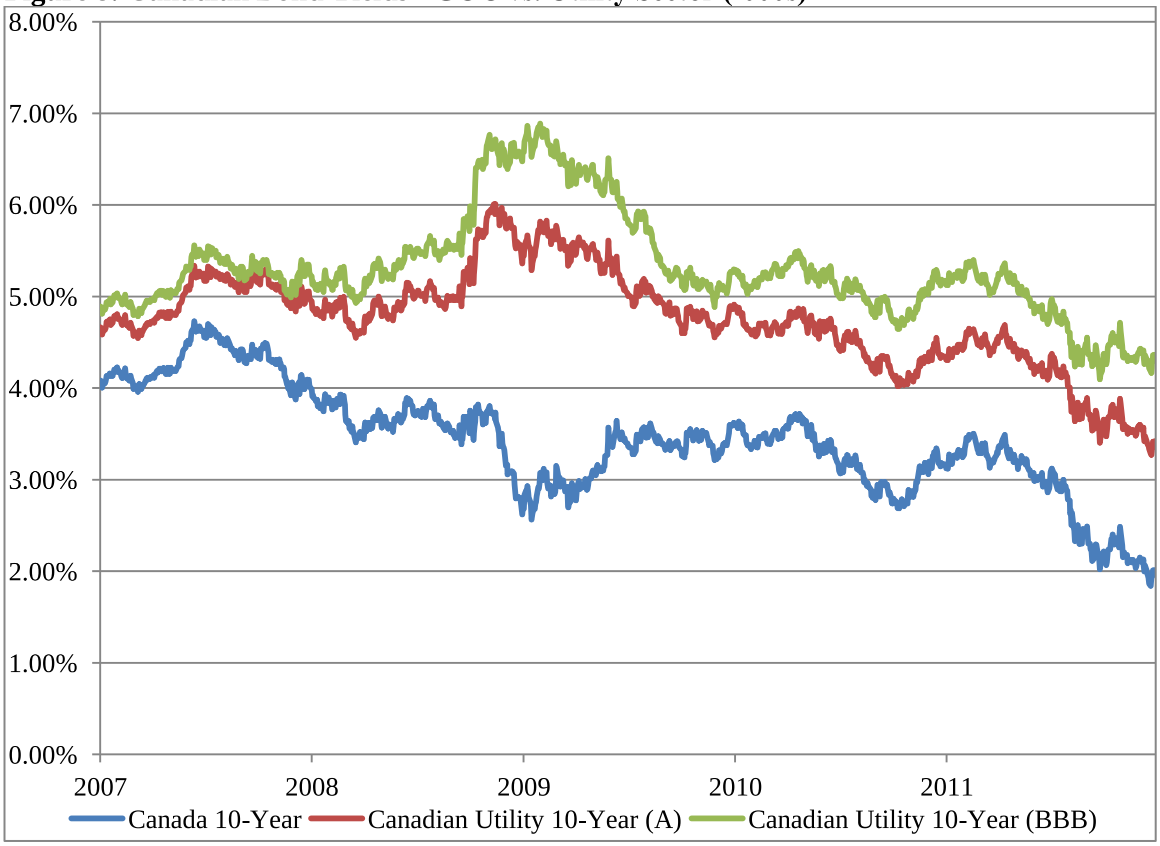
[72] The credit spread is quoted on a floating rate basis, typically a reference benchmark such as LIBOR, BAs, or Prime

[73] The Bank of Canada currently maintains overnight lending of 1.0%, which is very low on a historic basis (for comparison, the overnight lending rate was 4.25% in 2007). Economists expect the Bank of Canada to maintain the 1.0% rate in 2012.

[74] In discussions with other project financiers, many European banks have shut down or ceased their Canadian or North American project finance lending activities. At times, the decision to shut down was made even while in the late-stages of a transaction or a secondary sale of the debt to another lender

have not been adversely impacted as there remains strong demand among debt investors for infrastructure sector debt.

Figure 8: Canadian Bond Yields - GOC vs. Utility Sector ('000s)



Data source: Bloomberg

5.4 Conclusions

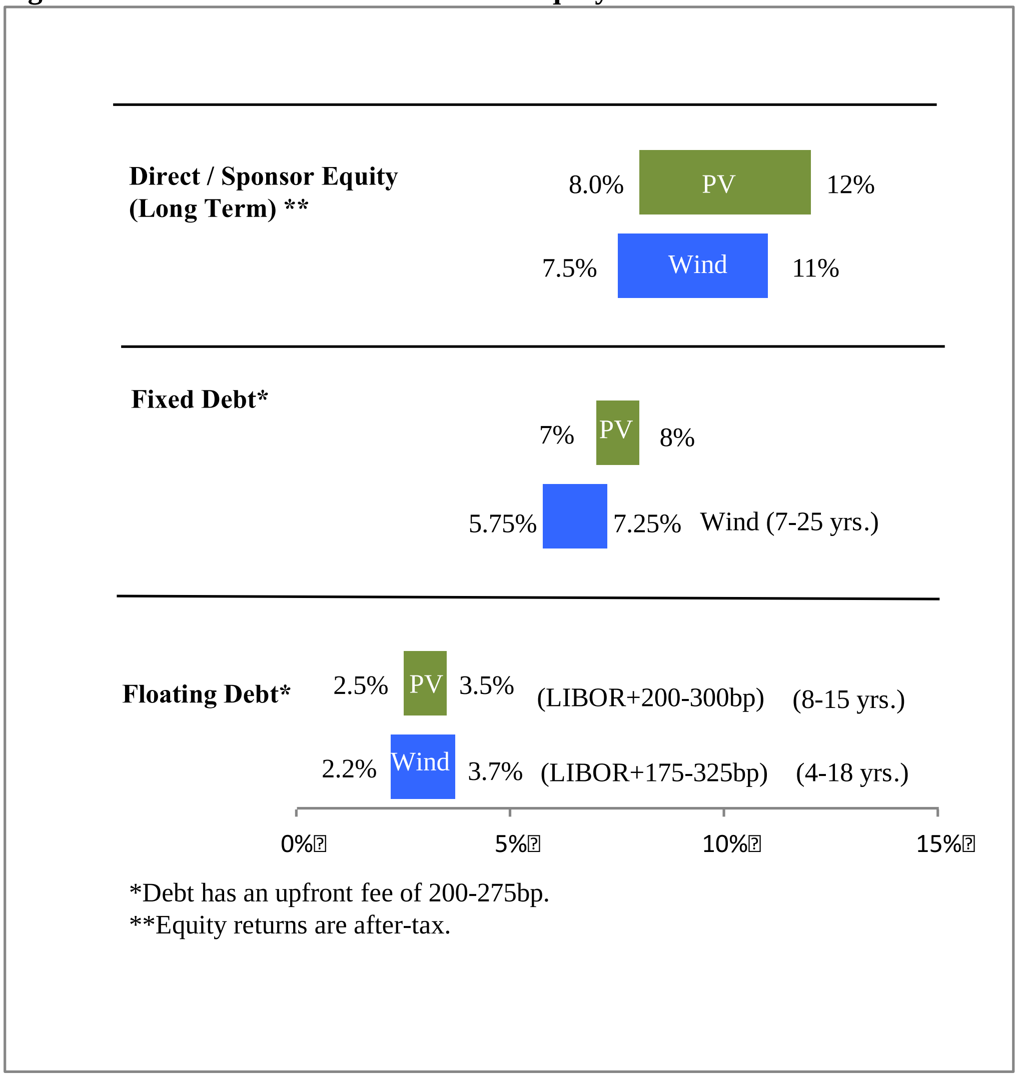
There does not appear to be any general impediment to raising capital for utility-scale renewable power projects in Atlantic Canada. While the market remains volatile and could change quickly, there is demonstrated interest and capital available from lenders and equity investors for utility-scale renewable power projects developed by IPPs.

Figure 9 summarizes the required equity after tax returns and cost of debt for wind and solar PV projects financed in the U.S. While the U.S. and Canadian capital markets are highly integrated, there can be differences in required underlying returns given differences in inflation expectations, monetary policy, and resulting investor expectations regarding exchange rates, and the use of more complicated tax structures. Given these differences, Figure 9 is presented because it represents a comprehensive review of the required return on equities and costs of debt. The greater spread for equity returns reflects that equity is paid after debt and is inherently more risky. The lower band for equity is associated with larger projects with higher-quality cash flows using

immediately after closing. Several European banks are reportedly in the market selling their entire renewable project finance portfolios.

proven technologies which can attract numerous equity investors who must compete to participate and the higher band is for smaller projects or those using nascent technologies with higher investor risk given limited operating performance or a lower-quality cash flow profile.

Figure 9: Estimates of Current Debt and Equity Terms



Source: Mintz Levin

6 Financing Options for Atlantic Canada

The preceding analysis and discussion indicates that there aren't unique challenges to financing renewable projects in Atlantic Canada. The primary challenges that renewable energy projects in Atlantic Canada face are similar to those present in other markets, with the most significant faced by smaller renewable energy projects developed by community or aboriginal groups. Given the economies of scale associated with financing renewable energy projects and the more limited financial resources of these groups, they face distinct challenges.

The following section presents a series of case studies, the first of which focuses on the financing of a large wind project and represents a relatively typical project finance approach which is commonly used to finance large renewable energy projects. The subsequent case studies review different programs and entities that have been established to help aboriginal and community groups overcome the barriers to financing smaller renewable energy projects. These case studies represent models that could be employed in Atlantic Canada.

6.1 Large Wind: Shear Wind

Purpose of Case Study

This case study considers Shear Wind, a local developer based in Atlantic Canada which was able to secure funds to build the $150 million, 62.1 MW Glen Dhu project located in Nova Scotia. Shear Wind is an example of a local developer's journey to secure development and project capital to build utility-scale renewable projects while remaining independent. The project reached commercial operation on March 31, 2011.

The Finance Model

Initial Stages
Shear Wind initially incorporated on December 17, 2004 with a focus on developing wind projects, primarily in Nova Scotia. Shear Wind's initial projects were joint-venture agreements with Renewable Energy Resources Ltd. (RESL), and Shear Wind was able to raise $6.1 million through three private placements of flow-through and regular Class A common shares to fund the purchase of six turbines and pursue the development of a portfolio of potential 50 to 100 MW wind sites in Nova Scotia.

In 2006, Shear Wind amalgamated with MWP Capital, a capital pool company (CPC)[75], to become a public company on the TSX. The new pro-forma company had $2.6 million of cash remaining on hand.

Development Costs
On August 30, 2007, Shear Wind submitted a proposal to Nova Scotia Power to construct the Glen Dhu project, and spent approximately $500,000 on the initial bid submission and expected

[75] A CPC is a publicly-listed, limited blind pool formed for the purposes of identifying and acquiring a business. The amalgamation of the blind pool and the target business is a qualifying transaction.

to incur an additional $500,000 in costs to bring the project to a construction ready stage. The initial 20 MW of the project was anticipated to be in-service by November 30, 2009.

However, Shear Wind was unable to secure the requisite financing due to the severe turmoil in the world financial markets between 2007 and 2009. Shear Wind incurred a $500,000 penalty for not having the first 20 MW of generation up and running by November 30, 2009 and incurred additional carrying costs to maintain the $2.7 million of deposits for the performance security and interconnection studies for the Glen Dhu facility.[76]

Securing Project Capital

However, the strengthening of the Canadian dollar against the Euro caused the project to become economic and the initial cost estimate of $270 million for a 55 MW project declined to an actual project cost of $150 million for the 62.1 MW project. On November 3rd, 2009, Shear Wind closed a private placement for $26.9 million from Inveravante Inversiones Universales, S.L. (Inveravante), a Spanish utility conglomerate with an international portfolio of wind projects. Upon closing of the private placement, Inveravante would own 62% of the common shares of Shear Wind on a fully-diluted basis, and on June 25, 2010, Shear Wind secured the additional equity funds required to build the 62.1 MW Glen Dhu project by selling a 49% interest in the project to Inveravante in exchange for $22 million. Securing these funds allowed Shear Wind to place deposits on the turbines ($24 million) and begin construction.

Project Details

- Capacity: 62.1 MW (27 Enercon E-82 2.3 MW turbines)
- Location: East of New Glasgow, Nova Scotia
- Total Capital Cost: $150 million
- Senior Debt Financing: $114.5 million (78%)
  - Construction Financing $107 million
    - 18 year term
  - $1.5 million LCs to NS Power
  - $6.0 million LCs for the debt reserve
- Equity Financing: $35 million (22%)
  - $32.9 million equity
  - $2.1 million subordinated loan by Inveravante
- The loan is secured by a first priority lien on substantially all of the assets of GDWE LP, the JV partnership between Shear Wind and Inveravante which owns the project company
- The lenders are Banco Bilbao Vizcaya Argentaria SA (BBVA) and Instituto de Credito Oficial (ICO)

[76] During this time period, some of Shear Wind's peers sold their projects or development companies to well-capitalized partners, and these partners were able to balance sheet finance the start of these projects despite volatile market conditions.

Summary
Shear Wind's Glen Dhu project is an example of a successful utility-scale wind development. Despite Shear Wind's efforts to remain wholly independent, the case study demonstrates that large-scale power development is expensive and difficult, and typically requires partnership or backing of a large, well-capitalized partner for a utility-scale project.

6.2 Cooperative: Water Power Group

This case study describes the approach being employed by a company in Ontario which has developed an alternative financing model for small renewable energy projects that does not require separate project assessments by lenders and does not require finding equity sources for each project.

The Water Power Group, as its name implies, is focused on developing and owning small hydroelectric sites in Ontario. These hydroelectric projects will be financed by forming unincorporated joint ventures that will obtain the equity and long-term debt for each project. Up to 49% equity is to be offered to community or aboriginal groups and by so doing qualifies for higher power purchase rates under the Ontario Power Authority's (OPA's) FIT program. The remaining project equity would be provided by the Water Power Group Limited Partnership. The Water Power Group has received a term sheet, subject to due diligence, for 40-year debt under favourable terms with up to 85% coverage which would be made available to these projects.

The model rests on four legs:

1) Use of local cooperative or joint venture capital for the equity portion of the investment. The cooperative is established to secure equity from interested stakeholders in the local community, which could include the municipality itself or individuals in the community. Under the cooperative structure participants will benefit from the diversity provided by investing in multiple projects.
2) Establishment of an overall cooperative structure within which to bundle each project. This allows debt finance for the individual projects to come under the broader umbrella so that each project does not require separate negotiations over the terms of the loans.
3) Replication of project types (all small hydroelectric projects, from 0.5-5 MW) so that the company's expertise and the business model can be extended over more projects.
4) Favourable treatment accorded community and aboriginal projects under the OPA's FIT program and the various programs put in place by the OPA and Ontario Government to promote the development of community and aboriginal projects.

The company has been in existence for four years. They look for opportunities such as small projects within a community. They seek to utilize existing dams in which they can install low-impact turbines to generate electricity.

Then they approach the community to secure local support for the project and local interest in participating in the development. They first seek equity investors within the community or surrounding communities. If they find them, the project can be set up as a Joint Venture between the Water Power Group and the local investors. Water Power Group will also assist the local community with forming the joint venture or coop, and with raising the local equity. The projects are not dependent on raising local equity. Water Power Group's preference is that community equity be up to 25%; debt can be up to 85%, requiring only 15% equity, but the preference is for community equity to be at the top of its range, thereby reducing reliance on debt. The debt can come from insurance companies, for whom longer PPA durations and the guaranteed nature of cash flows from the buyer are favourable.

If there are not enough individual investors in the host community or surrounding ones, it would rely on equity from the limited partnership or use a cooperative structure for which it is seeking approval from the Financial Services Commission of Ontario. The cooperative structure allows many projects to fall under the financial umbrella of the overall cooperative entity, eliminating the need to raise funds individually for each of these small projects. In effect, this structure allows these projects to be bundled. The company has a line of term debt that they can access as needed.

The company suggests that this model can also work as a public-private partnership between them and the municipality. They bring the technical expertise that the local community lacks.

The small size of the projects requires such a financing structure. For projects of the size being considered, which range from $3 to $10 million, it would cost about $200 thousand to raise the necessary funds. The venture capital community was not interested because of the small size of these projects.

Community support and involvement are keys to this model. The company expects that the community support shortens approval time.

Not all projects using a cooperative structure have succeeded. For example, the Pukwis Energy Co-op, which was planning to build a 20 MW wind farm on Georgina Island in Lake Simcoe, Ontario, as a joint venture with the Chippewas of Georgina Island First Nation, has suspended operations, citing (in a brief press release) problems with finance as one of the reasons for the suspension.

Other Supporting Programs

Ontario has a number of programs to support community renewable projects. The Community Energy Partnerships Program (CEPP) is a grant program to support community power in Ontario and assists community power projects through funding of up to $200,000. Eligible expenses include site investigation, resource assessment, business planning, engineering studies, and studies needed for Renewable Energy Approval or other approvals. As CEPP Program Manager, the Community Power Fund provides education about the CEPP, helps people through the application process, prepares the initial screening of and recommendations regarding applications, and provides approved project monitoring. Within the Community Power Fund, the Investment Funds Platform includes Direct Investment Funds to maximize funding for community power across the full capital spectrum, and fund management and fiduciary services designed to harness and accelerate fundraising capacity at the local level. Since 2007, CP Fund consulted with a diverse range of community power project developers, and allocated $1.5 million to assist in the development of 25 renewable energy projects owned by Ontario-based community and aboriginal groups.

6.3 Master Financing Facility

One financing approach that is receiving increasing attention in the US is a Master Financing Facility under which a developer bundles various projects together to reduce transaction costs and the overall risk profile. Under such a financing facility, the financier agrees to finance every project that a developer puts in service between specific dates up to some dollar amount assuming that the projects satisfy specific criteria agreed to by the developer and financier. These criteria are likely to include the project capacity factor, cost, and credit quality of the buyer (recognizing that the developer might also being seeking to finance projects in other jurisdictions or with other buyers). Alternatively, the developer will have the projects under contract allowing the financier to have a high level of comfort regarding the specific projects.

Master Financing Facilities are often used in the US to finance portfolios of solar PV projects. A critical element to financing such projects is efficiently utilizing the significant tax benefits that they generate. With a 30% investment tax credit and accelerated depreciation, tax benefits are critical to the financing of such projects. These transactions are structured around leases where the lessor owns the projects for tax purposes and the lessee sells the electricity, and collects revenue, much of which it pays to the lessor as rent for the use of the equipment, with the residual representing operating profit.

The difficulty in applying bonus depreciation (Class 43) tax-driven financing structures in Canada (based on current regulations) is that the purchaser for the tax attribute must already be generating similar income (such as income in the generation sector) to apply the accelerated depreciation against, whereas in the US the tax credits and accelerated losses can be applied against any income.

Canadian renewable power projects can elect to receive Canadian Renewable and Conservation Expense (CRCE) credits, which can be used by third-party investors. The CRCE program was adapted from a program to allow oil and gas and mining companies to write off the upfront soft costs incurred in development. For projects in the renewable power sector, effective use of this credit artificially forces the development into two phases – a turbine phase which pays for a set of test turbines to be built, followed by an infill construction phase which occurs after the 120-day test period. CRCE tax investors fund the capital for the turbine phase and are eligible to claim the majority of their investment as deductions against income in the first year of investment, be carried forward indefinitely, or flow through to investors under a flow-through share agreement. The artificial delay in the construction period means that developers need to balance the delay in the construction schedule with the cost of funds CRCE financing provides. The majority of renewable projects in Canada are not funded in this manner, although small developers may use CRCE to finance their development efforts. Contrast this to the US market where tax-driven financing structures are necessary in order to achieve a competitive cost of capital for financing renewable projects

Financing structures which aggregate smaller structures under one master facility can certainly take advantage of economies of scale (financing, operations, due diligence, etc) to improve returns. The key to the success of such financing structures is the upfront planning and co-ordination required to ensure that the projects are structured identically and occur within a very close timeframe. Recall that this is a critical driver for the structure employed by the Water Power Group.

A summary of generic terms for a US rooftop solar portfolio is shown in the summary Table 3 below.

6.4 Government Loans Guarantee: Aboriginal Loan Guarantee Program

Purpose of Case Study
This case study describes a government-funded program which provides equity funding to specified groups for projects of electricity generation from renewable resources or for transmission facilities. In the case of the Aboriginal Loan Guarantee Program (ALGP), the specified groups are First Nations or Métis communities.

The Finance Model
The Ontario government established the ALGP in September, 2009 in accordance with a commitment in its budget. ALGP has a limit of $250 million in total loan guarantees to First Nations and Métis communities to fund up to 75% of their equity portion for participation in renewable energy or transmission projects. In essence, this equity becomes subordinated debt which is junior to the senior debt. There is a limit of $50 million in guarantees for any individual project.[77]

The government assigned administration of the program to the Ontario Financing Authority (OFA), an agency of the Ministry of Finance which is responsible for managing the investment of funds and financial risk for the province. The OFA also provides all of the resources for the Ontario Electricity Finance Corporation, the financial successor to Ontario Hydro. The OEFC inherited all of the former Ontario Hydro's stranded debt and also became the counterparty to its non-utility generator (NUG) contracts. Through its work on behalf of the OEFC, therefore, the OFA has experience with managing debt for electricity generation and with administering contracts for electricity generation.

When the ALGP was established, it was committed to extensive due diligence before guaranteeing any loans. For that purpose, the OFA has engaged a due diligence provider which is assisting the OFA with the due diligence review. Given the extensive due diligence that is performed, the OFA is only able to evaluate three to four projects per year. Some parties have commented that the due diligence performed is equivalent to that for securing a bank loan; the OFA believes this to be appropriate given the significance of the financial commitments and the potential commitment of public funds. OFA also noted that banks can lean on the ALGP due

[77] OFA staff indicated that in Ontario loan guarantees aren't shown as a financial obligation, but are treated as a contingent liability that doesn't affect the Provinces' financial obligations unless there is a likelihood of default. These policies vary by jurisdiction. Furthermore, there is no loan loss reserve given the limited risk of default.

diligence and that this would reduce the burden on the project and proponent. Most projects are able to secure more favourable terms with lenders and the equity partners based on the technical support and expertise provided by the ALGP team. While there is a loan guarantee fee, it isn't based on cost recovery, but is expected to cover due diligence costs over the loan term. OFA suggested that a minimum project size limit would probably be appropriate given the significant due diligence resources devoted to evaluating each project.[78]

Only the Minister of Finance can commit the province financially, so the OFA's role is ultimately to make recommendations to the Minister.

The ALGP is in keeping with the Ontario government's commitment to promote the involvement of aboriginal communities in development of renewable energy in the province. Another incentive for such groups is that wind power and hydroelectric projects which are at least partly owned by aboriginal communities are eligible for an adder to the purchase price under the Feed in Tariff (FIT). The maximum adder is 1.5 cents per kWh for projects in which the aboriginal community has over 50% equity ownership.

Experience

Several First Nations have applied to the OFA for loan guarantees under the ALGP for renewable generation projects. The most advanced project is the M'Cheeging First Nation's Mother Earth Renewable Energy (MERE) wind power project, a 4 MW project on Manitoulin Island. The project is under construction with the bases for the two wind turbines installed in the summer of 2011.Turbine erection is underway and the project is expected to be in service in the spring of 2012. This project is 100% owned by the First Nation. It has received a loan guarantee of $8.5 million from the ALGP.

Also on Manitoulin Island, the United Chiefs and Councils of Manitoulin (UCCM – a group of the First Nations communities on Manitoulin Island) have applied to the OFA for a loan guarantee for their portion of the McLean's Mountain Wind project, a joint venture between UCCM and Northland Power, an experienced power developer. A complete Renewable Environmental Assessment has been filed with the Ontario Ministry of the Environment and construction start is anticipated in 2012.

The Moose Cree First Nation has received a conditional offer of a loan guarantee from ALGP for its equity investment in the Lower Mattagami project that is planned by Ontario Power Generation for the refurbishment and extension of four generation stations on the Lower Mattagami River.[79]

The process of applying to the OFA for a loan guarantee can itself add value for the project. For example, the OFA due diligence procedure will inspect the partnership agreements between the First Nation and its partner, giving OFA a chance to identify potential future problems in the agreement. The OFA also has helped the First Nations' consultants to understand the

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[78] OFA staff suggested that a grant program may be more appropriate if the focus were on smaller size projects.

[79] Source: newsletter from environmental lawyers Willms and Shier. http://www.willmsshier.com/newsletters.asp?id=63

requirements for the project to obtain finance. This can be an advantage during the application for debt finance.

Without the ALGP, it is doubtful that these projects would have progressed as they have. The First Nations communities do not have sufficient financial resources to contribute their share of equity to a project as large as McLean's Mountain. It is possible that they could find a lender or partner to provide a loan for their equity part, but such a loan to a First Nations community would likely carry such a high interest rate as to make the project no longer economic.[80]

Extending this model

Extending this model to community groups would require a commitment from government or other agency, and its successful extension might require more than simply the loan guarantee for the debt portion. The ALGP does not fund the initial development work, such as verifying the resource and performing feasibility studies. The cost of this up front work is much less than the cost of building the project, but is still significant enough to exhaust the resources of some communities. Aboriginal communities in Ontario have access to the Aboriginal Renewable Energy Fund, administered by the OPA, which funds from 40% to 80% of the development costs for renewable projects, with a maximum of $500,000 per project.

Non-aboriginal community projects in Ontario can obtain loans to help with the initial stages of a project. Infrastructure Ontario provides loans that help start capital projects of municipal corporations, including municipal electric utilities. Eligible projects include construction of alternative energy facilities, with maximum funding per project of $500,000. In addition, as noted in the previous case study, Ontario has its Community Energy Partnerships Program.

These two case studies illustrate the support that community-based groups need to help them organize and fund their participation in renewable energy projects. For communities which can access local financial resources, required assistance might be limited to institutional support for the renewable project organization and for the initial phases of the renewable project development. Such communities might also need some funding for development costs like resource assessment and preparation of documents for environmental and other approvals. Communities which do not have such financial resources will likely need financial support for the initial phases of project development as well as access to loan guarantees or other support to fund their equity investment in the project.

6.5 Community Economic Development Investment Fund (CEDIF)

Six CEDIFs have been awarded contracts for the development of twelve renewable energy projects under Nova Scotia's COMFIT program and are the primary financial vehicle that is being used to fund community renewable energy projects in Nova Scotia.

A CEDIF is a pool of capital, formed through the sale of shares (or units), to persons within a defined community, created to operate or invest in local business. It must have at least six

[80] Furthermore, financing projects can be difficult if they are located on reserve lands given legal limitations on land use and requirements for federal approval.

directors elected from the defined community. Investors in CEDIFs qualify for a 35% equity tax credit for Nova Scotia income taxes and are eligible for further equity tax credits of 20 and 10% at the 5 and 10 year investment anniversary. CEDIFs were established to reduce the amount of capital leaving the province through mutual funds and registered retirement savings plans. The CEDIF program was established over 11 years ago and over 40 CEDIFs have invested in a variety of local businesses. The CEDIF model is readily adapted to development of community renewable energy projects.

Eight CEDIFs in Nova Scotia have invested in the creation of Scotian Windfields Inc., which has a mandate to develop community-based wind energy projects in Nova Scotia. One of these CEDIFs is Colchester-Cumberland Wind Field (CCWF) Inc. CCWF has raised close to $1.5 million in equity, secured $1.2 million in debt and has one 800 kW Enercon wind turbine in operation with a 20-year PPA with NSPI and plans to install an additional 800 kW wind turbine and two 50 kW wind turbines. CCWF's success appears to be attributable to a dedicated management team and strong focus on marketing of the shares.

Power Advisory understands that some of the initial CEDIFs that were established to fund the development of renewable energy projects failed when the investments were used for early stage project feasibility assessment and the projects proved not to be economically viable or successful in securing a contract. The COMFIT program clearly mitigates these risks once an application has been accepted.

6.6 Toronto Renewable Energy Co-operative

The Toronto Renewable Energy Co-operative (TREC) was formed in 1999 with the purpose of developing and operating wind turbines. Its wind energy arm, WindShare, is the owner and operator of a single 660 kW wind turbine on the Canadian National Exhibition grounds near the Toronto waterfront. WindShare is a for-profit affiliate of the non-profit TREC.

The total cost of the project was about $1.6 million. This project was developed without any funding from a financial institution. It was built in 2002.

The project is a 50/50 joint venture between TREC and Toronto Hydro. Toronto Hydro paid half of the total project cost and received half of the energy produced as its return. TREC's share of the cost was funded by selling shares to residents of Toronto. Residents purchased a membership share for $1 and then at least five, but no more than fifty, Preferred Shares at $100 each. Over 400 Toronto residents purchased shares, fully subscribing the $800 thousand needed for the project.[81]

TREC's share of the project's initial development was funded through two preferential loans from government sources: a partially forgivable loan from the federal Environment Ministry and a loan from the Toronto Atmospheric Fund (TAF), an agency of the City of Toronto. The federal loan carried no interest. The TAF loan carried an interest rate of 5% and was repayable in nine

[81] Residents actually purchased more than $800 thousand in shares; the excess is held in trust pending investment in future projects.

equal monthly installments from May 1 to December 1 of 2003. Funds to repay the TAF loan came from the co-op members.

This project had a significant technical difficulty due to the failure of its turbine supplier. The supplier went bankrupt essentially as it delivered the turbine. TREC had ordered, and expected to receive, a 750 kW turbine, but the supplier only had a 660 kW turbine. It delivered the smaller turbine with a promise to replace it within a year, but that promise failed due to the bankruptcy. Also because of the bankruptcy, there could be no maintenance and support contract with the original equipment manufacturer. As a result, in the early years of the project the turbine was down for extended periods because parts were not available.

Because the project carried no debt and all of its equity came from Toronto Hydro and from residents willing to accept the risk of project non-performance, it was able to continue to operate throughout these difficulties.

TREC has extended this finance model to create SolarShare. This is a non-profit co-operative whose funds are used to finance a portfolio of large and small solar projects throughout the province. SolarShare sells bonds at $1,000 each, with a 5% rate of return and a five-year term.

6.7 Summary

The following table is a summary of the case studies. The ALGP isn't reviewed given that this information isn't publicly available. For a summary of current market terms see section 5.3.1.

Table 3: Summary of the Case Studies

Name	Shear Wind	Water Power Group	Master Financing Facility	Colchester-Cumberland Wind	TREC
Type of Project	Wind - Private Sector	Hydro – Private Sector	Solar – Private Sector	Wind - Community	Wind- Co-op
Size of Project (MW and $ mm)	62.1 MW ($150 mm)	$3 to $10 mm	<1 MW, portfolios aggregated to min 10 to 20 MW	1.7 MW ($5.15 mm)	660kW $1.6 mm
Capital Structure (% Debt/ Capital)	78%	75% to 85%	45% to 50% (debt) 35% to 40% (tax equity)	48%	50/50 JV with Toronto Hydro 0% debt on coop part
Return on Equity	n/a	n/a	Low-mid teens	9.2%	Varies with profits
Cost of Debt	Fixed rate of 3.462% + credit spread	n/a	n/a	5.75%	5% on Toronto Atmospheric Fund.
Term of Debt	18 years	40 years	15 years (depends on portfolio	5 and 10 years	Repaid within 2 years.

			composition and structure used)		
Structure of Debt	• $114.5 mm total • $107 mm construction financing • $1.6 mm PPA letter of credit • $6 mm for reserves	n/a	• Depends on the financing structure used	$2,475,000	Debt only for early development costs; repaid when co-op financing in place, within 2 years.
Source of Equity	• Inveravante (including a $2.1 mm subordinated loan) • Public markets	n/a	• Developers' sponsor for pure equity and tax equity sponsor for tax equity	Share offering	50% Toronto Hydro; 50% shares sold to local residents with $500 minimum and $5000 maximum investment
Source of Debt	• Banco Bilbao Vizcaya Argentaria SA • Banco Espanol de Credito SA • Instituto de Credito	n/a	• Project finance bank or tax investor which is also a lending institution	Local Cooperative	Environment Canada and Toronto Atmospheric Fund.

Source: Power Advisory

7 Policy Considerations

This chapter reviews government policies that can be used to promote the development of electricity generation from smaller renewable projects and then assesses how they affect project finance for these smaller projects.[82] For this Chapter, we have focused on policies that could find application in Atlantic Canada. Each policy is described, its pros and cons discussed, and where available its degree of success when applied in other jurisdictions evaluated. The chapter draws on information from the developer and financier survey the results of which are reviewed in Section 3.2, on the literature review presented in Section 3.3, and on the experience of the Power Advisory team.

In Chapter 8 of this Report we identify Strategic Policy Options which could be implemented in Atlantic Canada.

7.1 Policies to Support Finance of Renewable Generation

As noted in Section 3.3, policies to promote development from renewables fall in one of three main categories:

(1) Revenue support, or policies that increase the project's revenues or revenue certainty, or both;
(2) Cost reduction, or policies that reduce the cost of the project through direct or indirect subsidies on either construction cost or finance cost;
(3) Market access, or policies that facilitate a renewable project's access to the market either by improving physical facilities or by implementing policy favorable to renewables.

These policies are generally aimed at promoting renewable generation, not specifically at facilitating project finance. But the impact of the policies can be seen in the effect on project finance, both availability and terms. Renewable project finance requires that the projects be economically viable and that project risks are appropriately identified and assigned.[83] By reducing project risks or improving economic viability, government policies can remove barriers to financing renewable energy projects. These effects can be quantified as reductions in the finance cost or in the overall project cost.

A focus of this report is addressing the financing barriers faced by smaller renewable energy projects that are developed by community and aboriginal groups and the challenges posed by the smaller size of provinces in Atlantic Canada. Therefore, this chapter focuses on policies that are

[82] In considering these policies, we address as "small" projects with capacity less than 10 MW, connected at the distribution level, and developed by aboriginal or community groups. We recognize that there are few, if any, points where a project as large as 10 MW could be connected at the distribution level in Atlantic Canada, so the classification of particular projects as "small" under these criteria will sometimes require consideration of the characteristics of the project as a whole, rather than whether it strictly meets these criteria.

[83] In practice, financiers prefer to have a project that has assured prices through a contract with a creditworthy offtaker, a term for the contract that exceeds the term of the finance by several years, an experienced developer, and appropriate allocation of risk between the developer and offtaker.

best suited to these types of projects and expanding the scope of these provincial electricity markets. Appendix C reviews policies that are more appropriate for larger IPP projects.

7.2 Revenue Support Policies

Revenue supports can include a wide range of policies. This section will deal with six commonly used policies that could be, or have been, applied in Atlantic Canada. These are feed in tariffs (FIT), standard offer programs, production subsidies (e.g., ecoEnergy Program), renewable mandates like renewable portfolio standards (RPS), carbon pricing, and requests for proposals (RFP) for renewable energy supply.

7.2.1 Feed in Tariffs

FIT programs have been implemented in Canada in Ontario and, on a limited basis, in Nova Scotia and are being explored in British Columbia. They are widely used in Europe. FIT programs are very effective at enabling the construction of a large amount of renewable energy projects, particularly smaller projects. FIT programs provide economies of scale for financing which enable the construction of smaller projects by reducing the overall due diligence and documentation costs and facilitating the aggregation of smaller projects in larger and easier to finance issuances. (See discussion in Section 4.4) Small project sizes were frequently cited by investors, financiers and developers as a barrier to investment for such projects.

FIT programs provide for the purchase electricity from renewable resources at a price that is intended to enable the developer to recover its cost plus earn a reasonable rate of return. The prices offered differ according to the technology and its size given underlying cost differences. Most technologies for generating electricity from renewables exhibit increasing returns to scale, which means that the overall costs are lower for large projects than they are for small ones. Therefore, following the logic of prices which recover the project costs, larger projects typically receive FIT prices below those offered smaller ones.

Successful applicants to FIT programs receive a PPA from a government agency or a utility. The PPA sets the price for the electricity and the term of the agreement, which typically matches the life of the facility (and therefore influences the term of the financing). Most renewables receive 20-year contracts. Hydroelectric projects can receive longer contracts, with 40-year contracts offered in Ontario.

FIT programs have been very successful in attracting interest from developers with the interest based on the pricing offered, but some of the projects may never come into service. Typical barriers to project success are lack of access to transmission, inability to complete the project profitably at the FIT price, and inability to obtain permits and approvals to meet the required timetable. While FITs can have minimum requirements which ensure a minimum level of project development before contract award, they are typically fundamentally different from RFPs where there are often explicit criteria which favour mature development projects. This difference can cause FITs to have higher project attrition rates.

Table 4 below provides information on the market uptake of the Ontario FIT program. The program is still relatively new, so many projects are still under development or in approval processes. Many other projects are still awaiting assessment of available transmission capacity.

Table 4: Results of Ontario FIT Program

Technology	Applications Number	Applications MW	Contracts Awarded Number	Post-NTP MW	In-service MW	No longer active MW
Wind	295	11,845	77	42	215	2,446
Solar PV	9,633	8,451	1,791	95	26	1,334
Biomass	130	336	50	5	9	111
Hydro	104	366	49	53		23
Totals	10,162	20,998	1,967	195	251	3,914

Source: OPA. Data as of Feb. 3, 2012

NOTE: Post-NTP have received NTP but are not yet in service

These results show the very high level of interest prompted by the attractive features of the Ontario FIT program, primarily the price offered and the long-term PPA from a creditworthy counterparty, the OPA.

As shown above, Ontario's FIT has resulted in more than 10,000 applications for contracts for projects offering over 20,000 MW, for a market with a peak load of approximately 25,000 MW. Of these, almost 2,000, or almost 10%, have contracts executed, while almost 1,500 are no longer active.[84] A total of 183 projects are in commercial operation, providing 251 MW of capacity and a further 385 contracts, representing 195 MW, have received Notice to Proceed but have not yet reached commercial operation.

The inherent limits on the ability to integrate cost-effectively this amount of renewable generation are evident from the challenges of connecting this amount of renewable generation to the grid which has become the primary barrier to greater project participation. This raises the question as to whether consumers are better served by a policy which effectively allocates renewable project development based on available transmission capacity or on the basis of price such as in an RFP.

The German FIT program has been very successful in terms of the amount of renewable generation installed, as Table 5 shows.

[84] Contracts that are no longer active are those that have been rejected or withdrawn, had contract offers expire, or have terminated contracts.

Table 5: Capacity Installed Under German FIT

Technology	2007 MW	2009 MW	2010 MW
Wind: total	22,116	25,230	27,204
Wind: new	1,667	1,859	1,443
Solar PV: total	4,170	9,914	17,230
Solar PV: new	1,271	3,294	7,406
Biomass	3,290	4,102	N/A
Hydro	1,260	1,340	N/A
Gas*	647	641	N/A
Totals	34,421	46,380	53,283

*Landfill gas, sewage gas, and mine gas
Source: German Federal Ministry for the Environment, Nature Conservation and Nuclear Safety

The cost of the German FIT is paid by consumers through a surcharge on electricity prices which pays the difference between the FIT price and the market price. For 2012, this surcharge is scheduled to rise to almost €.04/kWh, or about C$.053/kWh.[85] In 2011 several countries, including Germany and France, reduced funding for their FIT programs due to financial constraints and the rapid reduction in price for solar PV panels.[86]

These examples illustrate the issues raised by a FIT program. The program's price stability and certainty attract investors in renewable energy sources. The benefit to the developer is assurance of earning a reasonable rate of return if it controls cost and performance.

The benefits to the ratepayer include the reduction in the environmental damage caused by electricity generation and, because the price of the renewables is fixed, a hedge against future increases in the price of fuels required by other forms of generation. For this, the ratepayer takes the entire demand risk and typically pays more for renewable electricity than from conventional sources.

The design of a FIT program therefore requires balancing the interests of the developer with the interests of the ratepayer and arriving at prices that properly reflect costs. In the study cited in Section 3.3, de Jager and Rathmann's[87] financial models suggested that programs like a FIT, which offer long-term price support with little risk to the developer, can reduce unit energy costs for a project by 20-30%.[88] This reduction in costs is based on a financial model which assumes that the revenue certainty offered by a FIT results in lower financing costs, i.e., lower cost of debt

[85] Bundesnetzagentur (German Network Agency), "Renewables contribution to change only slightly in 2012", press release Oct. 14, 2011.
[86] Renewable Energy Network for the 21st Century (REN 21), Renewables 2011, Global Status Report, pg. 49.
[87] David de Jager and Max Rathmann, op. cit.
[88] Power Advisory's financial model confirms up to the middle of this range.

and equity and greater leverage.[89] Power Advisory believes that a well structured PPA can provide equivalent lower financing costs and that an RFP can be more effective in ensuring that the renewable resources for which contracts are offered have lower overall costs. However, RFPs are better suited to larger IPP projects whereas FITs are better suited to smaller community and aboriginal projects.

Similarly to a RFP process with a financeable PPA, a FIT program can greatly facilitate financing for IPP developers. By providing price and demand certainty, it reduces risk and therefore finance rates thereby improving access to capital. IPP developers like FIT programs as they reduce the riskiness of development capital. Under a FIT a developer has greater control over project success. Furthermore, pricing is not competitive and provides higher returns for good sites. Uniform financing documents also allow IPP developers to accelerate the development of projects.

Well-designed FIT programs are likely to be appropriate and effective in Atlantic Canada. In theory, proper analysis of the costs for projects by size and technology would allow FIT programs to offer prices that will attract projects but not be overly generous. The price stability that FIT programs provide will help even small projects obtain financing. However, changes in the costs and performance of technologies cause FITs to have greater implementation risks for the buyer. These implementation risks can be managed through program design, e.g., procurement caps, price degression and regular program reviews.

7.2.2 Standard Offer Programs

Both standard offer and FIT programs offer long-term PPAs at a known rate for qualifying renewable generation projects. There are several differences between them in practice, although some programs called FIT programs have more of the characteristics of a standard offer program.

A standard offer program sets a uniform rate for all (or most) of the eligible renewable power sources. The rate is based on the value of the electricity. For example, the standard offer rate could be considered to be related to the system avoided cost, defined as the full cost of the cheapest alternative source of new power supply (including its environmental damage cost).

In Ontario, the standard offer price was based on the price at which renewable power had been offered in a recent RFP. The program set a size limit of 10 MW per eligible project because the standard offer program was aimed at projects too small to compete successfully in an RFP process. The Ontario experience with its FIT program showed that the rules did not prevent developers from offering large projects (cut up into smaller tranches), that the larger developers thus froze out smaller projects, that the rules did not sufficiently incent developers to make continuous progress on their projects, and that the prices were not high enough to attract many smaller projects. Nonetheless, some capacity was developed and put into service under the Ontario FIT program.

[89] Additional, albeit smaller, savings are likely to be provided by the lower development costs offered by a FIT.

Standard offer programs limit cost exposure for ratepayers, because they base the price offer on the value of the electricity to the system, not on its cost. As with other programs, ratepayers are exposed to higher costs from any premium of the standard offer price over the cost of other sources of electricity.

However, standard offer programs may not produce the desired amount of renewable supply because the price may not cover costs for many potential projects and technologies.

Issues in the design of a standard offer program include what forms of generation are eligible, whether there is a size cap on individual projects, whether there is a cap on the total amount of electricity to be purchased under the standard offer, the term of the PPA offered to standard offer participants, and how long participants have to bring their projects into operation.

Like FITs, standard offer programs provide favourable conditions for finance of renewable IPP development by giving a PPA with appropriate terms and a fixed price. Prices under standard offer programs are not technology specific so they are likely to be lower than with FITs, lowering the number of projects that can be financed. They also do not take account of the cost implications of smaller projects' inability to access economics of scale. They may not be as readily applicable as a FIT program in Atlantic Canada to attract small projects.

7.2.3 RFPs

RFPs provide revenue support by offering PPAs with a price specified to in their offers to successful bidders. If the PPAs are well designed and properly allocate project risks, they can form the basis for financing the project. Our survey gave the characteristics of such a well-designed PPA: the contract term should equal the life of the asset allowing a longer financing term; the price should be sufficient to cover the cost plus appropriate debt coverage; the offtaker should be creditworthy; and the terms of the contract should properly allocate risk between the developer and the offtaker.

RFP programs that are successful from the buyer's point of view attract significantly more offers than needed. That allows the buyers to choose suppliers that are technically competent and offer the lowest prices. RFP programs that are successful from the bidder's point of view are those that offer a PPA with favorable terms and a high probability of winning a contract.

Because the contracts in RFP processes are awarded to low-price bidders, there may be project attrition if the successful bidders find they cannot earn a reasonable return at their bid price. This risk can be mitigated by also considering the developer's experience and capabilities and assessing the project maturity. Some RFP buyers provide for this attrition by awarding contracts for more capacity or generation than they want to buy. In British Columbia, for example, BC Hydro's clean power calls are for 30% more than desired to allow for attrition. In Ontario, the OPA's Renewable Energy Supply III RFP had an attrition rate of about 13%, in part due to more stringent minimum thresholds.

In Atlantic Canada, RFPs have been used with considerable success as a mechanism to meet RPS requirements and have resulted in the construction and operation of over 600 MW of renewable power projects. However, these have been larger projects.

RFPs can also be designed to facilitate smaller projects. An RFP process to attract smaller developers should have less onerous participation requirements and offer a higher probability of success. To make the process less onerous, the process could accept projects at an earlier stage of development than is required for RFPs aimed at larger projects with more experienced developers. For example, it need not require that the participants already have all their financing committed nor that they already be engaged in the environmental permitting process. Requirements for resource data could also be eased. To increase the probability of success, the RFP could have an upper limit on the size of project to be accepted and have a large enough overall procurement total to ensure that several projects will be accepted.

7.3 Cost Reduction Policies

As the research cited in Section 3.2.3 showed, one of the most effective ways to reduce the cost of renewable generation is through reducing financing costs. That is the mechanism through which most of the revenue support policies work. A similar mechanism can work through policies which reduce risks or costs, since they have the same effect of increasing the rate of return and reducing the risk.

7.3.1 Loan guarantees

A loan guarantee from a creditworthy source (typically a government or government agency) directly reduces the finance cost by guaranteeing the repayment of all or a portion of the debt capital, thereby reducing the risk to the lender. Many projects would not be built without a loan guarantee because the capital would not be otherwise available or the project would be cost prohibitive to build.

Ontario has a loan guarantee program for projects undertaken by First Nations or Métis. The Aboriginal Loan Guarantee Program is described in more detail in Section 6.4 of this report. Without the ALGP, aboriginals would not be able to finance the extent of equity participation in renewable projects they have reached in Ontario. Some level of aboriginal equity participation is needed to qualify for the aboriginal adder to the FIT price for the kinds of renewable generation that are eligible for the adder.[90]

In the United States, the Department of Energy (DoE) administers loan and loan guarantee programs to support commercialization of technologies and technologies that avoid, reduce or sequester greenhouse gas emissions. They recently approved $1.2 billion in a partial loan guarantee to fund a 250 MW solar PV facility in California[91] and $1.4 billion in a partial loan

[90] In the Ontario FIT program, projects using eligible technologies can receive an adder, or premium, to the stated FIT price if they have equity participation from aboriginal or community groups. The level of the adder depends on the fraction of equity; it is a maximum of 1.5 cents per kWh for projects with 50% or more of equity coming from aboriginal group(s).

[91]US Department of Energy, "Energy Department Finalizes $1.2 Billion Loan Guarantee to Support California Solar Generation", Press Release, Sept. 30, 2011. http://energy.gov/articles/energy-department-finalizes-12-billion-loan-guarantee-support-california-solar-generation

guarantee for a multi-state project to install rooftop solar PV units.[92] The DoE programs have committed loans, loan guarantees, or conditional loan guarantees of almost $40 billion.

Other mechanisms are state-guaranteed loans from banks, as in Germany, or loans through special bond issues, as in the Netherlands.

Loan guarantees can be an effective tool at reducing the total cost of financing. Government loan guarantees increase the total amount of debt which can be raised against the project, thereby reducing the amount of (more expensive) equity which will need to be raised. In addition, Government loan guarantees can reduce the cost of debt, and the de Jager and Rathmann study[93] estimated that a government loan guarantee can reduce the cost of debt by 1-2%. They estimated that this reduction in the debt cost could reduce levelized energy cost by 5-10%. In the case of the Ontario Aboriginal Loan Guarantee Program, the impacts may be even greater, because lenders are likely to be reluctant to lend to these borrowers without a guarantee.

Before granting loans or loan guarantees, the governments perform due diligence similar to that of a commercial lender. With proper due diligence, and especially if the project has revenue support, the default rates on such loans will be low and the cost to the government low. Credit rating agencies may count the guarantees when assessing the total debt position of the government, which will not be a significant problem if the loans are not a large fraction of the total government borrowing capacity.[94]

Loan guarantees have been effective in creating opportunities for aboriginal groups to participate in the FIT program in Ontario. They have given the aboriginal groups the ability to attract the attention of experienced developers of all sizes, making the projects viable both technically and financially. Such guarantees could be very useful in promoting similar projects in Atlantic Canada.

7.4 Market Access Policies

Market access policies do not directly affect the cost of the projects. They can improve project economics by reducing uncertainty over access to the electricity supply system.

7.4.1 Market size

In most jurisdictions, overall size is not an issue for market access for renewables. Either the jurisdiction itself has a large enough market, as in Ontario or Germany, or it is strongly connected to large markets, as in the smaller New England states which have access to the broader New England market, or Denmark, which has access both to Germany and Norway. A large market allows the development of multiple renewable projects, each large enough to take advantage of available economies of scale in construction, finance, development and operation.

[92] US Department of Energy, "Energy Department Finalizes Loan Guarantee for Transformational Rooftop Solar Project", Press Release, Sept. 30, 2011. http://energy.gov/articles/energy-department-finalizes-loan-guarantee-transformational-rooftop-solar-project
[93] David de Jager and Max Rathmann, op. cit.
[94] However, as discussed, the obligations of the Aboriginal Loan Guarantee Program in Ontario are not considered an obligation of the Province.

As our survey showed, the size of the renewable market in Atlantic Canada can present a significant barrier to the development of projects. With the market for larger projects driven by RFPs, the number of RFPs is limited, which increases the risks of participation since projects which are unsuccessful must wait for extended periods for the next sales opportunity. Furthermore, a smaller market can make for smaller projects, and the smaller projects have more difficulty in attracting experienced developers and in obtaining finance.

The best remedy is to increase the market size, which in Atlantic Canada means stronger interconnections and cooperation. The premiers of New Brunswick and Nova Scotia have announced a continued commitment to collaboration on energy issues.[95] The announcement pointed to optimization of the transmission system as one area for collaboration. Both provinces have committed to increasing the share of renewables in their electricity supply.

Collaborative efforts that would increase the effective market size would include strengthening transmission ties between each of the various jurisdictions (e.g.,New Brunswick and Nova Scotia) and eliminating rate pancaking for projects within the control area.

Collaboration could also improve market size for renewables by coordinating procurement across jurisdictions. For example, the next RFPs could be issued jointly by the two provinces, increasing the amount of supply called for and therefore the number of potential projects of large enough size ($30-50 million in finance) to be more readily financed. This would help address a problem that several survey participants identified.

7.4.2 Renewable Energy Aggregator

As IPPs continue to look to develop renewable power projects in Atlantic Canada for sale into New England, they could profit from the presence of a renewable energy aggregator. Small developers, especially, might not have the market experience to be able to address issues of obtaining transmission access to New England, of selling renewable energy credits to buyers in New England, and of managing the delivery of the electricity. An aggregator which possesses these skills and knowledge can provide them efficiently to small developers.

An aggregator is better able to efficiently use transmission which a single project might not be able to justify contracting for given its load factor or the uncertainty regarding future market opportunities in the jurisdiction. Furthermore, an aggregator is more likely to possess the necessary forecasting and scheduling capabilities and to have a diverse mix of generation resources that better allows it to meet firm customer requirements and thereby secure higher prices. The aggregator would sell the renewable power into the most promising market over the available transmission path. That could include exports to the United States through existing interconnections, through new facilities built in conjunction with the Muskrat Falls development in Labrador, or through Québec to Ontario or the United States.

Improved collaboration of these kinds could help facilitate finance by broadening the markets for the power.

[95] Government of New Brunswick, "New Brunswick and Nova Scotia Commit to Continued Energy Collaboration", press release, May 16, 2011.

7.4.3 Transmission access

Renewable resources are generally not located close to loads, nor are they necessarily close to existing transmission facilities. Access to the transmission grid is a critical issue for renewables.

In Nova Scotia, as our survey pointed out, Cape Breton Island already has a surplus of generation and not enough firm transmission capacity to reach the load centre of Halifax. Yet Cape Breton has some of the best wind resource in the province. Bidders to the current RFP who want to propose projects on Cape Breton may find that they would result in network upgrades that cause their projects to be uneconomic.

In Atlantic Canada, an action that could increase the size of the market is to increase transmission interconnection capacity with New England. The recent addition of the International Power Line in 2007 has already increased the opportunity for trade. Effective expansion of export capacity to the major load centers of New England may require transmission reinforcement within New England unless new transmission paths are developed that allow direct access to the southern New England market which is the main load centre.

The *Ontario Green Energy and Green Economy Act* required transmission owners to give priority in access to electricity from renewable projects. The first projects approved in the Ontario FIT were those which could obtain access to the Ontario transmission system. Of the applications under the general FIT program, projects representing 6,973 MW of capacity do not have transmission access and are waiting for a test to determine if connecting them to the system is economic, as opposed to a total of 4,752 MW of capacity that has been awarded contracts.[96]

Governments can implement policies to ensure that adequate transmission is available to meet the needs of renewable developments. However, this is likely to result in higher transmission costs and overall electricity prices and is not necessarily in the best interests of customers. Ideally, planners and purchasers should consider the delivered costs of renewable energy. Even with such policies, however, developing new transmission lines is a lengthy process with consultations with landowners and others affected by the line as well as environmental considerations for a linear project over long distances.

If the transmission facilities are not built or reinforced to accommodate an increasing penetration of renewables, transmission congestion will increase. Managing transmission congestion and who bears the risk of it will be increasingly important. Requiring IPPs to bear this risk without limits or mitigation strategies will increase financing costs. However, passing these risks through to the purchasing utility and ultimately their customers can lead to poor project siting decisions. Solutions need to consider existing market rules and market structure and the available transmission infrastructure.

Network access can become an absolute barrier to the development of renewable generation facilities. In Atlantic Canada, some small projects may be able to connect at the distribution

[96] Ontario Power Authority, "Bi-Weekly FIT and microFIT report", data as of Dec. 23, 2011. Of the 20,574 MW submitted, the remainder have not yet had their reviews completed or they have been withdrawn.

level. Studying the capacity of the distribution networks to accept generation could help the development of such projects.

In Nova Scotia, for example, NSPI has a map on its website showing all of its distribution feeders, with links that give an estimate of the capacity of each station to connect COMFIT capacity.[97] This information is not dynamically updated to show the changes to capacity as new generators or new loads connect or as other changes take place to the distribution system. It therefore does not give a firm indication of available capacity at any time; that can only be determined by a Distribution System Impact Study, which is an essential part of the connection process. However, it does provide potential generators with basic information that can at least warn them away from feeders which are highly unlikely to accept their proposed generation, and can also point to those feeders more likely to be able to accept them.

In Nova Scotia, New Brunswick and PEI, the procedure for transmission connections is set out in the respective Open Access Transmission Tariffs (OATTs).[98] The New Brunswick System Operator issued a draft report on connection requirements for renewable generators in the summer of 2009, but it has not been made final. It deals only with projects of at least 5 MVa and is mostly concerned with technical issues. For procedure, it refers to the generation interconnection procedures in the OATT.

[97] http://www.nspower.ca/en/home/environment/renewableenergy/comfit/capacity.aspx

[98] Under that procedure, the potential generator applies to the transmission provider, who then performs a Interconnection Feasibility Study which begins the process of identifying necessary network upgrades and the costs of interconnection to be paid by the generator.

8 STRATEGIC POLICY OPTIONS

In this chapter, Power Advisory presents a number of strategic policy options that may facilitate the financing of small renewable electricity generation projects in Atlantic Canada. These options focus on those which will facilitate financing of small projects because our survey and case studies show that larger renewable energy projects can get financing under essentially the same conditions and with the same attention from lenders as do similar projects elsewhere in Canada.

The first group of strategic policy options is those which affect the Atlantic Canada region as a whole or which require concerted action by more than one government, provincial or federal. Because they would affect the entire region and generally are focused on overcoming barriers to trade within the region, these policy options would have a more significant impact on larger renewable energy projects. The second set of policies is focused more on addressing financing barriers faced by small renewable energy projects and these policies can be implemented by and for individual provinces.

8.1 System Integration

Electricity trade, including trade in renewables, can be increased by closer integration of the electricity systems of Atlantic Canada.[99] The extent of possible integration is limited by the capacity of the physical connections, but even within that context integration can be enhanced through better coordination and harmonization of the market rules.

The systems of New Brunswick, Nova Scotia and PEI are already reasonably well integrated, with the NBSO acting as the balancing authority for the entire area. However, as the co-operation agreement between the premiers of New Brunswick and Nova Scotia showed,[100] coordination can still be improved between the provinces.

Enhanced system integration would be promoted by reinforcing transmission interconnections among provinces, eliminating rate pancaking whereby parties pay transmission tariffs for each Province through which they wheel power, and employing consistent market rules. The Premiers of Nova Scotia and New Brunswick proposed such a strengthening of the transmission link in July, 2010, when they announced that the two provinces were exploring better connecting the provinces with a new 500 MW transmission line.[101] The addition of a direct transmission link from Newfoundland and Labrador as part of the Lower Churchill Project development would

[99] The *Eastern Wind Integration and Transmission Study* found that high penetrations of wind (20 to 30%) are technically feasible with significant expansion of transmission interconnections. The study found that "transmission helps reduce the impacts of the variability of the wind, which reduces wind integration costs, increases reliability of the electrical grid, and helps make more efficient use of the available generation resources." (p. 27).

[100] Government of Nova Scotia, Premier's Office Press Release, "Nova Scotia and New Brunswick will Work to Further Strengthen Regional Energy Co-operation", Nov. 19, 2010. The press release mentions "co-operation to improve transmission, system operation, renewable energy production and other aspects of their electric power systems."

[101] Government of Nova Scotia, Premier's Office Press Release, "New Energy Partnership Forged between Nova Scotia and New Brunswick", July 20, 2010.

allow that province to be linked to the electricity system in the rest of Atlantic Canada. A new line between Nova Scotia and New Brunswick would facilitate export of Lower Churchill and other renewable electricity generated in Atlantic Canada to the US Northeast.

8.2 Policy Harmonization

As described in Chapter 2, the four Atlantic Canada provinces have differing policies for promoting the development of electricity generation from renewables but they have similar goals and use similar instruments in some cases. In particular, New Brunswick, Nova Scotia, and PEI have RPS standards which are to be met by procurement of renewables through FIT (in Nova Scotia) and RFP (in all three provinces) processes.

So far, these have been separate processes, each with different sets of rules and different qualifications for bidders (e.g., mandating that projects be located in the province issuing the RFP). Harmonizing the terms and conditions of the RFP processes would relieve potential bidders of the requirement to become familiar with differing sets of bid conditions; allow them to potentially participate in multiple RFPs increasing the potential for being awarded a contract and could encourage more participation. Under this example, policy harmonization can be as simple as allowing renewable resources from other jurisdictions to satisfy the RPS or participate in the RFP. However, to the degree that there is a premium paid for renewable energy resources that will increase electricity rates, policymakers are likely to prefer that projects be located within the province so that there are offsetting economic development benefits realized. Power Advisory's study for NRCan showed that there can be significant benefits of allowing neighboring jurisdictions to meet RPS requirements.[102]

8.3 Renewable Aggregator

The New England states have renewable obligations of about 18 TWh. While the New England market isn't attractive at currently low energy prices, given this demand for renewable electricity it is expected to be an important market in the future.

However, the costs of identifying and negotiating trades, securing transmission, and scheduling them on the system do not decrease proportionately with the size of the trade. Therefore, for smaller sellers, these transactions costs are a relatively high fraction of the price they can expect to obtain. Such relatively high costs create a barrier to trade for small developers. Furthermore, one project, particularly wind projects which operate at maximum capacity a relatively limited amount of time, often cannot cost-effectively contract for required transmission capacity.

These barriers could be mitigated by the creation of an aggregator which would negotiate trades, secure transmission and schedule the electricity for a number of smaller developers. The aggregator could thereby spread the transaction costs over a larger volume of trade, making the trade feasible. Furthermore, having a portfolio of projects would enhance the degree of firmness of the energy offered and reduce the effective cost of transmission and the risks of imbalance penalties.

[102] "The Potential Impact of Relaxing Renewable Portfolio Standard Constraints on Canada-US Electricity Trade", March 31, 2011

The aggregator need not be a government agency. It could be part of an existing utility in Atlantic Canada or it could be a private firm that offers such transaction services. There are a number of entities that maintain a trading desk and already act as an agent for other generators in Atlantic Canada and possibly could become a renewables aggregator for the region.

Having a single aggregator for the region would also strengthen integration.

Governments could agree to create an aggregator or they could help to fund the establishment of an aggregator.

8.4 Facilitate Distribution Level Connection

As the Nova Scotia COMFIT program shows, connecting small renewable projects at the distribution level can avoid some of the issues with transmission congestion, at least initially. Allowing or facilitating such connection can increase the capacity of the system to integrate renewable projects. Because the capacity of the distribution system is inherently limited, such connections would be restricted to smaller-scale projects and to a finite total.

Governments could facilitate such connection ability by encouraging or requiring the distributors to study their systems and determine ability to connect renewable generation at specific points of their distribution systems. The NSPI website showing available capacity for each feeder could be replicated in the other Atlantic Canada provinces.[103] Such information is particularly important for a FIT program where connection capacity is likely to be a critical determinant of project viability and less important for an RFP where project selection is likely to be based on a range of criteria. Each province would have to consider whether the value of information to prospective renewable generators provides sufficient benefits to warrant the costs.

Distribution owners can also help facilitate generation connection by consulting with the groups who might propose to build generation. Such consultations can be more specific, but a large volume of them would also require a significant commitment of resources by the distributor.

8.5 Focused FIT Programs

A FIT program focused on smaller projects offered by target groups can attract participation by them.

For example, the Nova Scotia community FIT (COMFIT) program is narrowly focused on smaller projects and has attracted over 95 applications to February 2012. Only certain kinds of organizations are eligible to participate in this program and only with certain kinds of renewable technologies.

[103] Hydro One, the distributor serving the largest service territory in Ontario, has a similar website which provides a list of station connection capacity, a list of applications and an example showing how to calculate connection capacity. http://www.hydroone.com/Generators/Pages/AvailableCapacity.aspx

A focused FIT program can avoid many of the problems seen in larger FIT programs like those in Ontario and Germany.[104] For example, one of the conditions for the Nova Scotia COMFIT program is that the project be able to connect at the distribution level. This requirement ensures that no one project can be too large because of the limited capacity of the distribution system to accept injections.

These conditions avoid the potential for the program to become too large relative to the size of the electricity supply system or the requirements for renewable power. A FIT program could also be designed with caps, either on the total program or on some technologies (solar PV, for example).

8.6 RFP Processes

RFP processes are typically designed to ensure participation by large, experienced developers, as they have done in New Brunswick and Nova Scotia. Appropriately stringent conditions for RFP participation can increase the probability that all the projects selected in large-scale procurements are built.

But as noted in Section 7.2.3, RFP programs could also be designed to facilitate participation by small projects as defined in this Report. In our survey, small developers said that they were deterred from participating in RFP processes by several factors: the high cost and difficulty of meeting the mandatory requirements, including the financial requirements, and the risk due to the low probability of winning[105] and the high cost of participation relative.

To design an RFP process that could be more effective in attracting small bidders, and in facilitating the ultimate financing of the project, the procuring agency could soften the mandatory requirements, such as having less stringent financial and environmental approval requirements. Assuming that the RFP was targeted at community and aboriginal projects it could also be designed with a size cap for proposals or firms, ensuring that all successful projects meet the definition of small. For example, a 50 MW procurement could have a 10 MW size cap, thus ensuring at least five successful bidders. To broaden the pool of winners, proponents could be prohibited from being affiliated with other proponents.

Relaxing these mandatory requirements would increase the risk that proponents successful in the RFP process would be unable to complete the projects. The procuring agency would need to monitor progress closely.[106]

[104] These include adverse impacts on customer rates and overwhelming the system's connection capacity, triggering major network investment.

[105] Because so few winners can be successful given the amount of total capacity sought and the size of the likely offers.

[106] The PPA might also contain some financial penalty for successful proponents who are not able to complete their projects, recognizing that the size of these penalties will affect participation and that securing funding prior to contract award is more difficult.

8.7 Loan Guarantees

To facilitate First Nations' participation in renewable electricity generation, Ontario created its Aboriginal Loan Guarantee Program (ALGP). It has been essential to allow such groups to raise their equity portion of the investment.

Participation by First Nations in Atlantic Canada could benefit from similar action. Eligibility for such loan guarantees should be tightly focused on groups whose participation the governments want to encourage and which are likely to have difficulty in raising equity capital on their own. These would likely be limited to First Nations and community groups. In Nova Scotia, participation by community groups has been facilitated by the CEDIF, reducing the need for such a program in Nova Scotia.

Such programs do not have a high net cost to the government if due diligence is properly applied and default rates are correspondingly low. With no defaults, the program's net cost is its administrative cost if its total lending is not high enough to affect the government's credit rating or borrowing ability. However, performing the required due diligence can require considerable resources; recall that the OFA anticipates reviewing about four applications per year under the ALGP.

Loan guarantee programs are also effective at promoting the development of new technologies. A new generation technology being developed in Atlantic Canada is tidal power. Governments could offer loan guarantees to help fund the construction of tidal power projects. Such funding could be similar to that given other promising new technologies to help them achieve commercial scale. Government loan guarantees would be needed because other sources of funds, especially debt finance, seek projects where there is little technical risk and the technology is proven to be commercially viable. In this case, of course, the government is assuming greater default risk, with the intention of promoting a technology that would, if it proved viable, add to economic activity in the province.

8.8 Development Cost Funding

Groups that the government may want to target for participation in development, like First Nations and community groups, may have difficulty in funding the early development costs of a project. These include resource assessment, environmental assessment costs, project engineering, application costs, and other costs incurred before the project receives a contract and can access its project finance. In Ontario, the OPA funds such costs for aboriginal and community groups to a maximum of $500,000 per project.

The federal department of Aboriginal Affairs and Northern Development funds the ecoENERGY program for renewable energy for northern and aboriginal communities. It provides up to $250,000 in funding to aboriginal and northern communities for development activities, such as pre-feasibility and feasibility studies for renewable generation projects.[107] No aboriginal groups

[107] This program is not accepting applications at this time. The website says that an announcement of funding for the 2012-13 fiscal year will be posted as soon as it is available. http://www.aadnc-aandc.gc.ca/eng/1100100034258

in Atlantic Canada have accessed this funding for renewable energy projects, though those in other provinces have, including several in Ontario and Québec.

Community groups in Atlantic Canada may be unable to obtain sufficient funding for these up-front activities. Establishing a method of development cost funding would provide the necessary resources for early project development.

As for the loan guarantee programs, this development funding should be narrowly focused on those groups whose participation governments want to facilitate and which are not likely to be able to secure funding themselves. The program should also ensure that the groups being funded have a good likelihood of being able to develop a project.

In Nova Scotia, the existing community investment program, CEDIF (Community Economic Development Investment Fund) has become a vehicle for such funding, as described in Section 6.5 above. CEDIFs raise money from within defined communities which is then invested within the community or used to operate businesses within the community. They must not be charitable or non-profit. Many of the participants in the Nova Scotia COMFIT program have used CEDIF vehicles for their funding. However, using CEDIFs to fund initial project development activities is problematic given that these development activities are the most risky and investors in CEDIFs are seeking a return. Therefore, if these development expenses demonstrate that the project isn't viable and the CEDIF was organized to fund the development of this one project then investors will lose their entire investment.

8.9 Facilitate Cooperative Development

As the examples of the Water Power Group, CEDIF and TREC showed, cooperative developments, especially community-based cooperatives, can be effective in funding small-scale renewable energy projects.

Raising equity from the community can give the project more leeway because the local pool of equity investors may be more patient with returns that are lower than expected. For some members of local cooperatives, part of the benefit they receive is simply knowing that they have helped to build a renewable energy project in their community, a project that is visible to them and others. Not all community investors take this view, but an honest offering circular that describes the risks can mitigate impatience.

Such cooperatives may be able, as TREC was, to avoid institutional funding. Alternatively, as the Water Power Group's experience shows, the co-operative model can help to obtain loans if it allows a larger financial scale.

Governments can support these initiatives by enacting appropriate legislation so that renewable energy cooperatives can be formed. In PEI, municipalities are prohibited from investing outside their community. In Ontario the co-operative legislation primarily contemplated either buyer (as in agricultural) or seller co-operatives. Renewable energy co-operatives did not fit this model. Other limiting provisions might prevent a municipality from cooperating with neighboring municipalities when the project is not located within its municipal boundaries.

APPENDIX A: INTERVIEW GUIDE

Study on Financing of Renewable Electricity Projects in Atlantic Canada

Background:
Power Advisory LLC (Power Advisory) has been engaged by Atlantic Canada Opportunities Agency (ACOA) to identify and analyze the challenges in the financing of renewable energy projects in each of the four Atlantic Provinces with jurisdictional comparisons to other regions. The study is to identify and evaluate the key economic conditions and risks that affect the availability and cost of capital for independent power producers associated with renewable electricity projects. The study is focusing on the risks, the economic and market conditions and the policies, actions and favourable market that have mitigated these risks/conditions elsewhere. A key deliverable will be recommendations as to how the Atlantic Provinces may take full advantage of the opportunities afforded by the region's renewable energy potential.

Purpose of Interviews:
We are conducting interviews with renewable project developers, investors and lenders to guide us in identifying and analyzing the challenges in financing renewable energy projects in each of the four Atlantic Provinces. Your participation in this interview will enhance our understanding of these issues. Thank you for your participation.

Q1. In what provinces in Atlantic Canada have you attempted to develop renewable energy projects?

New Brunswick □ Newfoundland and Labrador □ Nova Scotia □ Prince Edwards Island □

Q2. Have you developed renewable energy projects in other jurisdictions?

If so, please identify:____

Q3. What types of renewable energy project have you attempted to develop in Atlantic Canada?

Wind □ Biomass □ Hydro □ Tidal/Wave □ Solar □ Other

Q4. What size of projects have you tried to develop in Atlantic Canada?

Size ($ mm): ______________________ Capacity (MW): _______________________

Q5. Have you been successful in your project development efforts in Atlantic?

Yes □ No □ Please explain:____
____
____

Q6. Have there been issues associated with securing financing for your Atlantic Canada project development efforts? Yes □ No □ Please explain:____

____
____

Q7. Have the financing issues for your Atlantic Canada renewable projects been related to securing a market for the output of the project? Yes □ No □ Please explain:____
____
____

Q8. Are the financing challenges for renewable projects in Atlantic Canada attributable in part to a lack of information for investors and lenders? Yes □ No □ Please explain:____
____
____

Q9. Are there unique technology risks that renewable projects in Atlantic Canada face relative to other jurisdictions? Yes □ No □ Please explain:____
____
____

Q10. Are there unique (or greater) regulatory risks that renewable projects in Atlantic Canada face relative to other jurisdictions? Yes □ No □ Please Explain:____
____
____

Q11. Do you view the risks and economic conditions that affect the financing terms for Atlantic Canada renewable projects as less favourable than those that are likely to be available for similar projects in other jurisdictions? Yes □ No □ Please explain:____
____
____

Q12. Do you believe that there is a shortage of equity and debt financing available for renewable projects in Atlantic Canada? Yes □ No □ Please explain:____
____
____

Q.13 In your experience, would you say that the difficulty of financing renewable energy projects in Atlantic Canada is greater than that in other jurisdictions? Why? Please explain:
____
____
____

Q14. Is this shortage of equity and debt financing more pronounced for small renewable projects in Atlantic Canada? Yes □ No □ Please explain:____

____

____

Q15. Do you have any recommendations regarding how the risks and economic conditions for project financing can be made more favourable for Atlantic Canada renewable projects? (Please make sure where possible to tie these recommendations to the challenges and barriers you identified.) Yes □ No □ Please explain:____

____

____

____

____

Q16. Are there financing vehicles that can be employed that would improve the availability of equity and debt to renewable energy projects in Atlantic Canada? Please identify:____

____

____

Q.17 Are there ways in which governments or buyers of the output of these projects can work with the private sector to ensure that these risks of these projects are accurately assessed and not overstated? If so, please identify:____

____

____

Q18. Please list any other concerns or forms of support you believe would assist your project development not already addressed:____

____

APPENDIX B: INTERVIEW NOTES

Interviewers: Ching-yen Chen, Potian; John Dalton, Power Advisory; Mitchell Rothman, Power Advisory
Subject: Financing Renewable Projects in Atlantic Canada
Date: Nov 15, 2011 (Phone Call)
Category: Lender

* Company has financed renewable projects (all except Tidal) in Canada and the US. Within Atlantic Canada, has financed wind and hydro projects in Nova several provinces

* Key determinant for whether they will participate is size of the debt

* Target size is $75 to $100 mm. At sizes above $100 mm they will syndicate to parties (2 or 3 other parties on a club basis). Minimum size is $50 mm.

* Minimum size is due to corporate pressures of a $mm target amount of capital to deploy and limited internal resources. Time commitment per transaction is "fixed", which is why they target larger deals.

* Have also found a strong correlation between size and competency (e.g. more experienced developers are typically associated with larger projects). Less experienced developers require more hand-holding

* Examples in other jurisdictions show that well-structured projects of a good size will attract capital at competitive prices (think Saskatchewan was seeking 250MW but received over 5,000 MW in bids)

* Otherwise, no real issue with investing in Atlantic Canada

* Key issues in determining whether to invest capital is an examination of the PPA agreement to ensure the terms make the project financeable. For renewable power, there will be no project without a contract in hand, but to get financing the contract terms must be reasonably favourable to the developer. An example of a less favourable contract is one with large penalties to the developer for missing minimum output levels.

* Risks which need to remain with equity - completion, availability, interconnection

* Risks which need to remain with the PPA counterparty - resource (no min production levels but availability ok), curtailment

* Risks which should not be in the contract - local content (introduces risks, is expensive and is not an effective means of producing long-term employment)

* No issues with current contracts in Atlantic Canada, and in some cases they are more favourable to the developer than those elsewhere. For example, in Ontario the developer takes the curtailment risk.

* Other determinant is making sure the project has access to transmission

* Ensure the transmission rights and curtailment risks are on a queue basis (and not like Texas where every entrant is equally curtailed)

Other topics
* Ability to bundle smaller projects together into a larger financing - possible but difficult because projects must be built around the same time (<6 months), and the ownership must be common between projects

* Best way to encourage renewable development in Atlantic Canada is to ensure transmission connection is available and contracts are financeable.

*We look for some experience in a developer, but we have been willing to be patient and we have done a fair amount of holding developers' hands.

*FIT programs - does not like it / believes RFPs are much better in procuring the most competitive pricing for projects

* With any procurement process, they key is having a pre-qualification process or stringent threshold requirements to ensure credible bidders (or you will have the Ontario experience)

* Atlantic Canada has an advantage over some other jurisdictions, such as BC, because the First Nation rights are clearer

Interviewers: Ching-yen Chen, Potian; Mitchell Rothman, Power Advisory
Subject: Financing Renewable Projects in Atlantic Canada
Date: Nov 15, 2011 @ 2 pm (Phone Call)
Category: Medium-sized Developer

* Has not yet invested in Atlantic Canada

* No issue with region, just that projects brought to them previously have not been economic subject to further DD

* Flaw identified in diligence which reduces economics, or risks in the PPA structure

* Main issue is whether the PPA economics are rich and secure enough to support the project: How secure is the revenue stream? It is then their lookout as buyer to determine how secure the output is.

* Governmental agency (good credit risk)

* Dispatch rules do not constrain revenues
* Typically buys the early stage project from the developer (developer has secured land, permits, wind data)

* Seeks minimum project sizes in order to be competitive. This is what limits the number of projects they see in Atlantic Canada

* wind - 30 - 50MW

* water - 4-5 MW

* solar groundmount – 7-10MW

* solar rooftop - large portfolio

* biomass - 20MW

* Projects smaller than those identified above are typically too small to support the fixed cost overheads both physical and administrative (eg., legal) -> economies of scale are key

*But if the project is good enough, size is not an issue. We will look at projects of any size if the PPA is rich enough. Could finance a 5 MW project without borrowing, but would prefer to aggregate, say, 6 x 5 MW projects in the same area.

* Strong preference for the counterparty to be the government. Harder to get comfortable with a corporate credit beyond 10 years.

* Local content is an issue

* Limits ability for the developer to seek and get competitive pricing for turbines, because local content limits the number of suppliers you can choose between etc...

* Likes the FIT program

* Reduces the cost / risk of development capital

*What Atlantic Canada can do to encourage renewable development: make sure prices are sufficient. The pool of potential developers in Atlantic Canada is relatively small.

* There is no difference between Atlantic Canada and other places in terms of financing, but the utilities there are smaller and don't always have a lot of experience buying power under contract.

Interviewee: Senior Power Experts
Interviewers: Ching-yen Chen, Potian, Mitch Rothman, Power Advisory
Subject: Financing Renewable Projects in Atlantic Canada
Date: Nov 29, 2011 @ 2:00 pm (In Person Meeting)
Category: Lender / Debt Capital Markets

* Have not recently raised capital for a renewable energy project in Atlantic Canada, but have raised capital in the region (no issue)

* Have been active in the power sector

* Would expect project sizes would need to be a minimum of $50 mm to get people interested, but that's a rule of thumb (street view). Ability to go smaller sizes on an individual transaction, but that's typically on an expectation of more deals

* Smaller deals ($10 million and up) would be handled by the small/medium business group at the local branch. But local branch lenders would not have wind expertise, and would be referred to the Toronto office

* Toronto office happy to have informal calls with the local branches, but that likely won't be sufficient to get deal across the line. The real issue on getting smaller deals across the line is that the friction costs (e.g. wind studies) would overwhelm small deals

* Like other Canadian banks, we generally do not lend for terms beyond 10 years. For a renewable energy project with a 20 year life, that can create problems because either they have to try to pay off the loan much more quickly from the same cash flow, or they have to refinance

* The number of players looking to be active in this industry is declining, particularly the number of European banks.

Interviewers: Ching-yen Chen, Potian; Mitch Rothman, Power Advisory
Subject: Financing Renewable Projects in Atlantic Canada
Date: Nov 22, 2011 (Phone Call)
Category: Large Developer

* Active developer in the Atlantic region

* See no real issues different in Atlantic Canada than developing wind projects in other jurisdictions, and they have been active nationally and internationally.

* See no difference between Atlantic Canada and other jurisdictions in terms of project attrition. The project in New Brunswick that had a PPA was not specific to Atlantic Canada, but to a federal/provincial issue. Expect project attrition in Ontario also.

* An issue for contracting now in Atlantic Canada is the changing structure in New Brunswick, where NBSO is being folded back into New Brunswick Power.

* The basic problem for renewable development in Atlantic Canada is the size of the market and therefore of the projects. The RFP in Nova Scotia addresses a small market with no transmission access to the United States. A more integrated market would help because, for example, the larger the market the easier it is to balance.

* So not advocating any changes

* Have generally used balance sheet finance, but we see no problems getting project finance in Canada.

* Have not looked at biomass projects in Canada

* Minimum project size: 30 MW. Smaller developers might have more trouble project financing because they lack the track record, but the finance should depend on the economics of the project and on the PPA.

* We like FIT programs, though the current FIT program in Nova Scotia is too small for us.

Interviewers: Ching-yen Chen, Potian; Mitch Rothman, Power Advisory
Subject: Financing Renewable Projects in Atlantic Canada
Date: Nov 22, 2011 (Phone Call)
Category: Small Developer

* Applied to BDC for finance and all local resources (co-ops) for finance for an earlier project in Atlantic Canada, but little knowledge of wind or support

* Went to life companies, but little interest given management's lack of experience at the time

* Unable to finance in Nova Scotia with private funds (amount + term)

  * In theory, wealthy local families could fund but they aren't interested in buying and holding wind assets

  * They could possibly fund a development team (buy-flip model)

* Public / Government funds weren't interested as it didn't meet criteria for job creation (still unclear on why that's the case)

* Currently funded by equity provider which provides equity commitments over construction, no debt until complete. This was especially critical / helpful during the financial crisis (08 – 10)

* Believes it's easy to get financing for $100+mm projects, but much more difficult to get funding for a local developer on COMFIT 1-4 turbine projects where the project size is $5 mm to $20 mm. Financial institutions won't look at them because they are too small. Think a gov't guaranteed loan is the answer. A government guaranteed loan would also simplify the structuring process as friction costs are significant – for example there were five different consultant teams required to review the equity transaction.

* Believes wind projects are fantastic for the local economy as the BOP funds are entirely spent in the local community. Very strong regional support as a result.

Interviewee: Head of Power
Interviewers: Ching-yen Chen, Potian
Subject: Financing Renewable Projects in Atlantic Canada
Date: Nov 24, 2011 @ 9:30 am (In Person Meeting)
Category: Financial investor

* Have looked at projects in Atlantic Canada but found it difficult competing against NSP

* Beneficial that new process is independent of NSP as it was not a level playing field previously given cost of capital advantage

* Do not like contracts where the asset is given back at the end of the PPA; strong preference for retaining rights to the land, etc. (he thought there was a PPA in the region which that was the case)

* Think a co-ordinated and integrated strategy across Atlantic Canada is the answer, easier to enforce a co-ordinated balancing strategy across the ISOs, particularly given the regional generation mix types (nukes in NB, coal in NS, renewables in PEI, etc…)

* Projects tend to be small (20 – 25MW in size), would be more comfortable going into the region with a critical mass of at least 100 MW

* Have not looked at region in any detail recently, but would want to understand the curtailment risks in more detail, particularly in NB, given the large base load supply from Lepreau

Interviewee: Wind Developer
Interviewers: Ching-yen Chen, Potian; Mitch Rothman, Power Advisory
Subject: Financing Renewable Projects in Atlantic Canada
Date: Nov 22, 2011 @ 9:00 am (Phone Call)
Category: Medium-sized Developer

* Charge of renewable development in the NE region

* Sees no difference investing in Atlantic Canada vs other jurisdictions, may even be a little easier as community support is better than some jurisdictions and permitting is easier in New Brunswick, so we have to spend less on pre-approval processes. There is no problem sourcing equipment or finding EPC contracts in Atlantic Canada. When financed in Atlantic Canada, talk to the same people in the same banks in Toronto.

*Generally, the biggest issue for renewable development in Atlantic Canada is the number and size of opportunities for procurement of renewable energy, just one in New Brunswick and one in Nova Scotia. And these are small compared to those in Québec or Ontario just because the markets are smaller. The problem is that each RFP attracts many bidders but produces relatively few winners, and the projects they win tend to be relatively small. So the chances of winning and the rewards of winning are small.

*What would make things easier is a FIT program, even one only for small (10 MW) projects, rather than the RFP where the chance of winning is only 1-5%.

*We would not touch a project of less than 10 MW wind or 5 MW solar unless there is low risk of not getting a contract. We looked at Nova Scotia COMFIT but concluded the projects are just too small.

Local content rules are OK in Ontario because it is large enough to attract the manufacturers. Will look at projects as small a $25 mm equity cheque

Interviewee: Senior Power Professionals
Interviewer: Ching-yen Chen, Potian
Subject: Financing Renewable Projects in Atlantic Canada
Date: Dec 6, 2011 @ 2:00 pm
Category: Lender

* No problem financing projects in Atlantic Canada, mainly wind and also hydro. Have done it before.

* Size is main driver, hard to look at anything less than $50 mm debt in size. Think this will be hard for anyone to provide such loans on a nonrecourse basis.

* Government support would help but it's still hard to chase because it's so small

* For it to be considered a non-recourse loan, it would have to very, very close to government debt for it to not be a power project / need to evaluated by the project group

* Key is what's the size, quality, experience of the sponsors? Even if the size is there, developer needs experience to do non-recourse financing

* Concern about lending to biomass projects as they have had a chequered past. Tougher - start-up, supply, and O&M concerns than other technologies

* Expect views to be similar to other banks

* Smaller projects summing to $50 mm in size is, possibly ok, but careful that it's just not 4 separate financings. Much prefer one project of $50mm.

* While $50 mm is a minimum size, sweet spot $100 mm and up, preferably structure 300 to 400 mm, but hold $75 mm or so

* Commonly mini-perm structures - construction + 5/7 (maybe not 10)

* Pricing is ~250 bps, but moving target and unclear the impact will be from turbulence in the European markets. Some are dropping out even when committed. See more impact on term than pricing.

* Focused on wind development in the region. While the company has historically looked at biomass, they are no longer pursuing that.

* If Nova Scotia and New Brunswick were both planning an RFP in the same time frame, it would be an interesting idea to run it jointly and to break it up into 10 MW segments to increase the number of developers who can win.

APPENDIX C: POLICIES FOR LARGER IPPS

Renewables Obligations (Renewable Portfolio Standards)

Renewables obligation programs require a certain fraction of the total electricity supply to be from renewable resources. The requirements are stated as a fraction of the supply at a certain date, often with intermediate requirements. These programs are also called renewable portfolio standards (RPS). In the United States, 29 states have RPS requirements and 8 more have renewable goals. Recent U.S. legislative proposals had provisions for a national RPS program.

The obligation is generally placed on the entities responsible for providing electricity (load-serving entities). [108] They can meet it by producing renewable power or contracting directly with a producer. They can also purchase credits (called Renewable Energy Credits or Certificates, or RECs) from renewable power producers. RPS programs create a separate market for the renewable attributes of renewable power which allows developers to recover a portion of the cost of their projects.

The expectation of RPS programs is that RECs would be priced at the incremental cost of renewable power projects beyond the value of conventional resources. If they are priced below that, the REC value will not be sufficient to allow the project to be financed. If they are priced above that, additional renewable producers will enter the market and create a surplus of RECs.

In the United States, RPS requirements range from 12.5% by 2021 in North Carolina to 33% by 2020 in California.

The important design features of an RPS, in addition to the requirement and timetable, are the definition of renewable resources which can satisfy the RPS, including whether they have to be from within the jurisdiction or not and whether there are any technology carve-outs, requiring some of the renewable energy to come from specified technologies or specified project sizes; whether the renewables muse be procured in certain ways (e.g., only through RFPs); and whether there is an amount that responsible entities can pay if they do not have enough RECs to meet their obligation, which then forms a cap on the price of the RECs.

The effectiveness of an RPS program depends primarily on how much new renewable construction it requires. The programs in California and Massachusetts, for example, have high enough requirements that they cannot be met entirely from in-state resources. They have attracted investment in neighboring jurisdictions, including investment in Atlantic Canada to create RECs that can be sold in Massachusetts.

De Jager and Rathmann[109] conclude that renewables obligations are less effective than FITs in reducing capital cost, because by their nature the value the electricity of the RECs in the market cannot be known in advance. The effectiveness of RPS can be undermined by changes to the resource eligibility requirements. RPS programs are regulatory creations. Changes to these

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[108] Power Advisory reviewed US RPS programs for Natural Resources Canada and assessed the potential trade impacts of relaxing provisions in RPS that represent a barrier to trade. "The Potential Impact of Relaxing Renewable Portfolio Standard Constraints on Canada-US Electricity Trade", March 31, 2011.

[109] Op. cit.

regulations, particularly the types of resources that are eligible to participate, create uncertainty, cause prospective participants to be reluctant to participate, and signal to others the risks of participating if rules can be changed that affect the value of the program.

To be effective in Atlantic Canada in removing barrier to the financing of smaller renewable projects, RPS programs would have to carve out requirements for smaller or community-based projects. RPS programs that require RFPs will exclude smaller developers for whom the cost of bidding is prohibitive for an RFP with a highly uncertain outcome.

Production Subsidies

Production subsidies are amounts paid to the generators on the basis of their output. They are stated as an amount per kWh. Such programs are typically funded from general government revenues, though they may be funded from a charge on electricity rates. These policies are reviewed in this Appendix because they have more typically been applied at the federal level and because one application of such policies, production tax credits, is more applicable to larger companies which can take better advantage of the tax benefits.

Canada has had several such subsidy programs. The first was the Wind Power Production Incentive (WPPI), which paid from $.012 to $0.01 per kWh for all output for the first ten years of a project producing wind power. WPPI was replaced by the ecoENERGY for renewables program, which paid $0.01 per kWh for 10 years. No applications for ecoENERGY were accepted after March 31, 2011.

The United States has had similar production incentives, but they have typically been only for limited periods and based on production tax credits (PTC) with renewal dependent on passing new legislation in the Congress.[110] These have created flurries of investment activity as the end of each funding period approached. With *The American Recovery and Reinvestment Act of 2009*, the PTC was expanded to include an investment tax credit and a Treasury Grant given the difficulty of finding investors with tax appetites that could utilize the tax credits generated. The PTC is scheduled to expire for wind projects at the end of 2012 and the Treasury Grant required that projects expend at least 5% of the project cost by the end of 2011. Extension of the PTC is uncertain given fiscal pressures in the US and the current political environment. Recent moves in Congress have created more uncertainty and prompted a warning from the American Wind Energy Association about the economic consequences if the PTC is not renewed.[111]

One disadvantage of the PTC is that it requires taxable income to realize the benefit and project developers typically don't have sufficient income tax liability to fully utilize the PTC. This requires that a party be brought in who has the necessary appetite for these tax benefits. To induce these parties to participate in the project, the developer typically has to provide a sufficient return which leads to discounting the value of these tax benefits. This can result in a loss of value and higher transaction costs which increase overall financing costs.

[110] The PTC is currently about 2.2 cents/kWh for wind projects, almost twice what the ecoENERGY program offered.
[111] American Wind Energy Association, "As wind manufacturing job losses loom, bi partisan wind PTC extension drive continues", press release, Feb. 16, 2012.

The PTC, ITC and Treasury Grants provide US renewable energy projects with a policy-based competitive advantage which must be overcome by renewable energy projects in Atlantic Canada by more favourable renewable resources or lower project costs. Failure to renew the PTC would reduce this advantage.

Production subsidy programs are less effective than FIT programs in overcoming financing barriers. A 10-year production incentive payment lasts only half as long as a FIT contract, and generally half as long as the financing for the project.

The developer still takes the market price risk in a competitive market, unless it has a contracted price. Since the payments are funded from general government revenues, they are vulnerable to cancellation when the government experiences fiscal problems. .

Carbon pricing programs

Programs that increase the price of conventional electricity sources relative to renewable resources provide revenue support by increasing the value of the renewable electricity. A critical issue with the design of such programs is how the carbon price is established: administratively or by a market for carbon. These programs are placed in this Appendix because they generally do not provide sufficient revenue certainty to facilitate financing of small renewable projects.

An administratively determined price could be established by estimating the environmental cost of global warming due to greenhouse gases, i.e., on the basis of damage cost estimates. The carbon price would then be included as part of the price of electricity generated using fossil sources, increasing the market price of electricity in general and therefore providing additional revenue for electricity from renewables, since they have no carbon emissions.

Carbon can also be priced through a cap and trade system or on a market basis, under which emitters are given carbon limits and allowed to purchase allowances from others in the system. A group of Northeastern US states has one such program, the Regional Greenhouse Gas Initiative (RGGI). These states have committed to a schedule of carbon reductions and allocated the reductions among themselves. Carbon allowances are auctioned every three months; the clearing price in all four of the 2011 auctions was US$1.89 per short ton, the minimum allowable bid. These auction results show that CO_2 allowances are not in short supply given reduced electricity demand from the recent recession and lower natural gas prices which is causing some coal-fired generation to be displaced by natural gas-fired generation. At this price, the impact on the competitive viability of renewable generation is relatively small. The RGGI auction price would increase the price of electricity from coal-fired plants by under $2 per MWh, or about 4% of the average electricity price in New England in 2010.[112]

The effectiveness of carbon pricing in promoting renewable electricity therefore depends on the prices for carbon and on the relative costs of renewable and conventional generation. Carbon pricing addresses a global, not a local, problem. Carbon pricing would be most effective as a federal program, but no Canadian federal government has shown interest in a program that prices carbon emissions.

[112] Based on 1999 emissions data, the most recent available, from the US Energy Information Administration of 0.95 tonnes of CO_2 per MWh from coal-fired plants.

To be effective in facilitating finance for renewable generation development, a carbon pricing program would have to provide enough additional revenue and revenue certainty to reduce the risk to the renewable developer and therefore affect financing conditions. As shown by the RGGI experience, carbon pricing programs have not yet achieved that level of price support and price certainty.

Accelerated depreciation

Accelerated depreciation programs reduce the present value of the capital costs by allowing them to be depreciated more rapidly. In Canada, Class 43.1 treatment allows a 30% per year declining balance treatment for the assets, rather than a 6% per year declining balance. In the United States, the 5-year Modified Accelerated Cost Recovery System allows onshore wind energy facilities to be depreciated over 5 years. These programs are included in this Appendix because the proponents of small projects in Atlantic Canada are likely not to have income tax liability (community groups or aboriginal bands) or to be small enough that accelerated depreciation has less financial impact.

De Jager and Rathmann[113] calculate that these programs can be quite effective, reducing the levelized cost of energy in Canada by 5% for the 20 MW wind project that they consider.

For these programs to be most effective, however, the entity owning the project must be taxable and have income subject to tax in the power sector as these programs effectively defer taxes so they do impact government fiscal positions. In the U.S., the impacts of these programs is more significant as investing in renewable generation can be used to offset a corporations' income in other sectors; whereas in Canada the tax benefits must be utilized within the same sector.

[113] Op. cit.

Regional Clean and Renewable Energy Market Opportunities

Study Findings

Prepared for:

Atlantic Energy Gateway

Atlantic Canada Opportunities Agency
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List of Revisions

September 4, 2012

1. Revisions were made to the Executive Summary, Section 2.8 and Section 5 to reflect Nalcor's transmission access into New England that has been secured through various agreements related to the Muskrat Falls hydroelectric and associated HVdc transmission (Labrador-Island Link and Maritime Link) projects that were executed by Nalcor and Emera on the July 31, 2012. This information was not available for the previous final report released March 30, 2012.

2. Revisions were made to the Executive Summary, Section 3.1 and Section 5 to reinforce the existence of up to three primary and distinct markets for clean and renewable energy from Atlantic Canada in New England.

3. Updated provided on August 21, 2012 action by U.S. Court of Appeals for the D.C. Circuit vacating the Cross State Air Pollution Rule (CSAPR) and its implication to New England.

4. Revisions made to the Executive Summary and Section 3.1.1 to highlight a recent amendment to the Commonwealth of Massachusetts Laws, Section 116 of Chapter 169 of the Acts of 2008, signed into law on August 3, 2012, that includes allowing hydroelectric power, regardless of whether that power is eligible under the renewable energy portfolio standard, for meeting the state's goal of at least 20 percent of the Commonwealth's electric load by the year 2020 through new, renewable and alternative energy generation.

5. Update made to Section 3.2.1 that large hydro of any size is now eligible to count towards the Vermont Sustainably Priced Energy Enterprise Development Program ("SPEED") renewable energy goals as stated in 30 V.S.A. 8005(d). Previously only hydro facilities up to 200 MW could be included towards the state renewable goal.

6. Update to Section 3.2.7 that in 2012 the Maine Legislature introduced Legislative Document 1683, "An Act to Lower the Price of Electricity for Maine Consumers." The Act proposed to eliminate the 100 MW limit on the size of hydroelectric facilities included in the definition of renewable capacity resource. This Act died on April 13, 2012 due to unresolved disagreements between the House and the Senate.

7. Clarification in the Executive Summary and in Section 2.7.2 that ISO-NE and NEPOOL participants have undertaken a Forward Capacity Market redesign effort in response to FERC's March 30, 2012 FCM Order in Docket No. ER12-953. The redesign proposals under consideration relate to various capacity pricing mechanisms.

Executive Summary

The Atlantic Canada Opportunities Agency (ACOA), in collaboration with the Federal and Atlantic Canadian Provincial Governments, retained Navigant Consulting Ltd. (Navigant) to conduct this Atlantic Energy Gateway (AEG) study to identify market opportunities within the international northeast region for Atlantic Canadian clean and renewable energy. The purpose of the study is to review and summarize provincial and state clean and renewable energy policies, supporting clean and renewable energy consumption targets and mandated clean and renewable energy procurement policies for Atlantic Canada and New England.

To assess the potential export opportunities for clean and renewable energy, Navigant analyzed the following factors: current and anticipated future regional market demand drivers, market barriers to the movement of clean and renewable energy within Atlantic Canada and New England, and regulatory issues and considerations. The study also provides a summary of renewable portfolio standards (RPS), local content requirements, domestic production and consumption targets, emission reduction targets and associated environmental regulations, general market conditions and any policies or initiatives that may impact the supply or demand for clean and renewable generated electricity. In addition to the above, Navigant also prepared a detailed overview of the New England power market to put the above factors in context with the market characteristic.

Based on the above identified factors, regulatory and market drivers, and the defining characteristics of the New England market, Navigant makes the following observations related to the opportunity for exports of clean and renewable energy to the New England power market.

1. There are three distinct "markets" for clean and renewable energy in New England: 1) the New England energy market; 2) the New England capacity market; and 3) the various state Renewable Energy Credit (REC) markets. Generally speaking, the energy market is accessible to any supplier that can physically deliver electricity into New England and, similarly, the New England capacity market is accessible to any supplier with a firm transmission path into New England. The rules for the individual state REC markets vary from state to state depending on each state's Renewable Portfolio Standard (RPS), particularly with respect to the type of renewable energy that is eligible to participate in the market.
2. The New England energy market has a significant amount of combined cycle natural gas capacity. Due to the discovery of unconventional gas resources, gas prices are low, and are projected to remain low for the foreseeable future. This has resulted in natural gas being on the margin for over 70% of the time. For example, with an average historic market average of 8,600 Btu/kWh and a natural gas price of $5/MMBtu, wholesale electricity market prices would be about $43/MWh (USD).
3. The New England capacity market has a significant surplus of capacity and is projected to remain in surplus until the end of the decade. This is the result of the implementation of a forward capacity market (FCM), and rules that support demand response resources competing against generation

resources and imports to compete for a capacity supply obligation. It is expected to result in capacity prices that are well below the cost of new entry.[1]

4. The investment required for complying with some or all of the forthcoming environmental regulations could make a number of plants candidates for retirement. These plants include older steam coal, gas, oil units that are marginally economic and at risk of retirement given their limited operation. The removal of 3,500 MW of such capacity from the market would, as ISO-NE has indicated, eliminate much of the surplus capacity.
5. Current RPS policies provide incentives for renewable generation. There are no specific requirements, policies, or incentives for clean energy (e.g., large hydro and nuclear power), and the region does not distinguish between clean resources and other resources, such as natural gas plants, that meet the federal and state emission regulations.[2] The Production Tax Credit, if extended, would provide a competitive disadvantage to the AEG initiative.
6. New England's Load Serving Entities are currently relying on a mix of renewable resources located in New England, New York and Canada to meet their RPS requirements. New England is not expected to have enough "local" renewable resources to meet future RPS requirements. New England will need to import renewable energy certificates (RECs) to meet its future RPS requirements.
7. Large hydro cannot participate in the current RPS programs. There have been proposed changes to the RPS programs in Maine, Connecticut, and New Hampshire for allowing large hydroelectric generators to qualify. However, these legislative changes have either died due to unresolved differences or have been tabled for later discussion.[3] Maine currently allows hydroelectric resources of up to 100 MW to participate in its RPS Program and Vermont allows hydroelectric resources of any size to count towards its SPEED Program renewable energy goals.
8. There have been few long-term contracts offered to renewable energy projects in New England, and no long-term contracts offered to projects located outside of New England. If regional project development stalls and demand exceeds supply, long-term contracts could be offered to projects outside of New England to ensure compliance.
9. Maine is currently export constrained, with an abundance of natural gas-fired generation capacity. This has led to low energy prices, lower capacity prices, and reliability issues. The proposed transmission projects are being developed to address reliability concerns, and do not explicitly address the export constraints between New Brunswick and Maine or between Maine and the rest of New England.

[1] ISO-NE and the NEPOOL market participants are currently evaluating alternative capacity market frameworks for the New England capacity market. These discussions are taking place as part of confidential settlement discussions resulting from FERC's Order in Docket No. ER12-953. Based on the limited information available on the ISO-NE website, the redesign efforts are exploring a number of options, such as demand curve and mechanisms to reduce price volatility.

[2] In August 2012 Massachusetts amended its Green Communities Act now allow hydroelectric power, regardless of whether that power is eligible under the renewable energy portfolio standard, for meeting the state's previous goal of at least 20 percent of the Commonwealth's electric load by the year 2020 through new, renewable and alternative energy generation. Policies for supporting this goal have not yet been developed.

[3] Recent legislation to eliminate the 100 MW limit on hydroelectric resources died on April 13, 2012. The bill died due to unresolved disagreements between the House and the Senate.

10. Through various transmission service, access and rights agreements with Emera, Nalcor will have access through Nova Scotia and New Brunswick into the New England markets upon completion of the Muskrat Falls hydroelectric and associated HVdc transmission (Labrador-Island Link and Maritime Link) projects. In combination with the transmission access it currently has through Quebec, these agreements will allow Nalcor to sell any available energy and capacity into the New England energy market that is not utilized by Nalcor or committed for delivery into Nova Scotia. If the electricity available from Nalcor is eligible to participate in any of the state REC markets, it would also be able to access these markets.
11. Hydro Quebec is currently well positioned to sell into the New England market and its favourable market positioning is expected to continue into the future. It has transmission access into New England, surplus energy and is building additional hydroelectric generation facilities.

This report is organized to describe the factors, drivers, and market barriers that have been identified by the AEG participants. The above findings were a result of the research and information contained in the report and presented in the order that they appear in the report.

1. Introduction

The Atlantic Canada Opportunities Agency (ACOA), in collaboration with the Federal and Atlantic Canadian Provincial Governments, retained Navigant Consulting Ltd. (Navigant) to conduct this Atlantic Energy Gateway (AEG) study to identify market opportunities within the international northeast region for Atlantic Canadian clean and renewable energy. The study was prepared with the collaboration and guidance of the AEG Project Steering Committee, which provided feedback throughout the study process.

1.1 Study Objectives

The purpose of the study is to summarize provincial and state clean and renewable energy policies, support clean and renewable energy consumption targets, and mandate clean and renewable energy procurement policies for Atlantic Canada and New England, with two primary objectives:

- Assess and quantify opportunities for both short-term and longer-term clean and renewable electricity exports (including associated renewable energy credits) from Atlantic Canada to New England; and
- Assess opportunities for increasing the flow of clean and renewable energy within Atlantic Canada based on the concept of a more fully integrated Atlantic Canadian electricity market.

The outcome and findings from this study is anticipated to support associated planning, system planning, and transmission planning models and studies.

1.2 Approach

Based on the above study objectives, Navigant prepared this study to assess the potential export opportunities for clean and renewable energy. As part of this assessment, the following factors were analyzed: 1) current and anticipated future regional market demand drivers, 2) market barriers to the movement of clean and renewable energy within Atlantic Canada and New England, and 3) regulatory issues and considerations.

The study also provides a summary of renewable portfolio standards (RPS), local content requirements, domestic production and consumption targets, emission reduction targets and associated environmental regulations, general market conditions and any policies or initiatives that may impact the supply or demand for clean and renewable generated electricity.

To more fully appreciate the market drivers, barriers, and other dynamics in the New England marketplace, we also provide a detailed overview of the New England power market to put the above factors in context with the market characteristic. We include a detailed summary of the demand forecast, RPS requirements and projections, transmission projects, capacity market rules and auction results, interregional transactions, competition from neighboring markets, and a summary of recent solicitations.

1.3 Organization of the Report

The report is organized in five sections. Section 1 contains this introduction which outlines the scope and objective of the study. Section 2 provides an overview of the New England market. Section 3 provides a summary of the export opportunities for clean and renewable energy to New England. Section 4 provides a summary of the opportunities for greater interprovincial electricity trade, summarizing major fundamental drivers associated with each provincial electric market. Section 6 provides our general observations and conclusions on the opportunities and barriers for clean and renewable resource sales in New England.

2. Overview of the New England Market

This section provides an overview of the New England bulk power market. The purpose of this section is to provide an overview of the peak demand and energy requirements, existing generation portfolio and anticipated changes to the resources, and a summary of the capacity and energy markets. The intent of this information is to provide fundamental information on these areas such that AEG participants may appreciate the market dynamics and drivers that influence the decisions and requirements for procuring clean and renewable energy.

2.1 *Market Summary*

The New England electricity market includes over 14 million people in six states: Connecticut; Maine; Massachusetts; New Hampshire; Rhode Island; and Vermont. The region's more than 400 market participants comprise the New England Power Pool (NEPOOL). NEPOOL was formed in 1971 by the region's electric utilities to ensure that New England would avoid any future region-wide power failure similar to the Great Northeast Blackout of 1965. Currently NEPOOL's participants own more than 350 separate generating plants and approximately 8,000 miles of interconnected transmission lines.

In 1997, ISO New England (ISO-NE) was created by the Federal Energy Regulatory Commission (FERC) to operate and oversee the reliability of the competitive wholesale electricity markets in New England. In 2003, ISO-NE adopted the FERC's Standard Market Design which includes features such as Locational Marginal Pricing (LMP). In 2005, FERC designated ISO-NE as the Regional Transmission Organization (RTO) for the New England region providing ISO-NE broader authority over the day-to-day operation of the transmission system and greater independence to manage the power grid and wholesale markets.

The New England system is summer peaking. On July 22, 2011 it experienced a peak demand of 27,702 MW, the second highest peak demand on record. New England's overall demand for electricity fell sharply from 2007–2009, primarily due to the recession, then climbed in 2010, but has remained below 2003–2008 levels. New England's bulk power generation and transmission system provides for more than 34,000 MW of capability, which currently includes approximately 2,600 MW of demand response.[4]

2.2 *Demand and Energy Forecast*

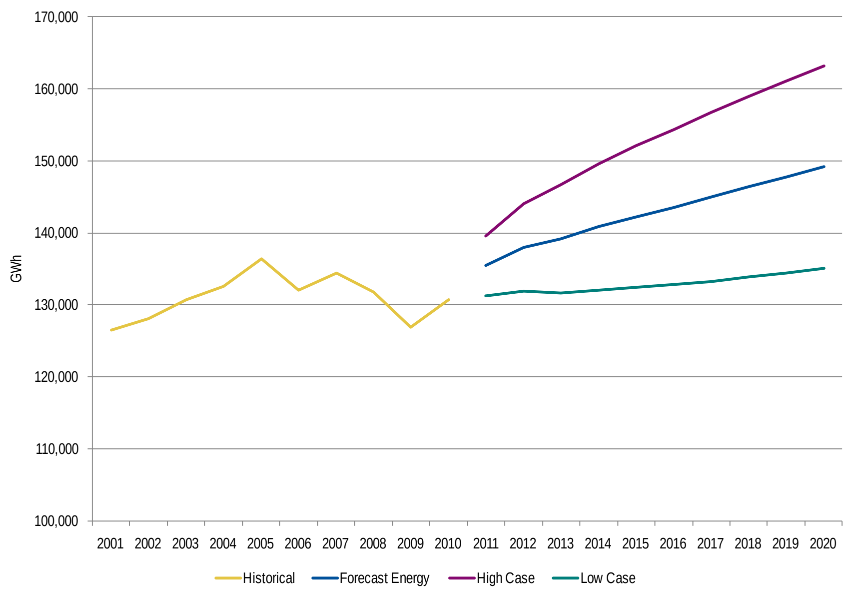
An important driver of New England's projected requirements for renewable resources is its annual energy forecast. Each year ISO-NE prepares a long-term energy and peak demand forecast using an annual model of projected total energy consumption within the ISO-NE control area. The forecast takes into account projections of personal income and gross state product forecasts. The model also incorporates flexible price elasticity to better account for structural changes over the historical period (e.g., increasing impact of energy conservation). For each region, except Maine and Vermont, the demand forecast incorporates a flexible Cooling Degree Day weather elasticity to better account for structural changes over the historical period (e.g., impact of greater penetration of air conditioners).

[4] Based on the results of the most recent Forward Capacity Auctions, there is 3,350 MW of demand response with a capacity supply obligation for the 2013/2014 capability year.

Lastly, the forecast includes estimates of the impact of new Federal Electric Appliance Standards that would not be captured by econometric models.

Based on the ISO-NE's latest forecast, the economy began a sluggish recovery from the recession in 2010, with annual energy growth averaging 1.5 percent from 2010 to 2014 and 1 percent thereafter. Summer peak demand is expected to grow slightly faster averaging 2.4 percent from 2010 to 2014 and 1.3 percent thereafter. Figure 2-1 provides a comparison of the historical and projected energy forecast. This figure also includes a high and low energy consumption forecast, driven by economic recovery and weather.

Figure 2-1. Historical and Forecast Energy Demand



Source: ISO-NE's 2011-2020 Forecast Report of Capacity, Energy, Loads, and Transmission

The energy forecast prepared by ISO-NE is a key driver in projecting the amount of renewable resources that will be required to be procured over the next ten years. As discussed later in this report, changes in projected economic recovery and demand growth are key drivers in renewable requirements.

2.3 *Demand Response and Energy Efficiency*

2.3.1 Demand Response

The ISO has active and passive demand resources. Active demand resources are dispatchable and respond to ISO dispatch instructions, while passive demand resources provide load reductions during previously established performance hours. The ISO-administered demand-resource programs fall into three basic categories: active demand resources that reduce load to support system reliability, active demand resources that respond to wholesale energy prices, and passive demand resources that reduce load through energy efficiency and similar measures. As further explained below, demand response programs participate in the forward capacity market (FCM), competing directly with generation resources for a capability obligation.

Demand response has increased significantly in New England, from under 600 MW in 2005 to just under 3,000 MW in 2010. Much of this increase is due to the economic incentives provided by the FCM rules initiated in 2005. More discussion of the FCM is contained within the markets section of this report. The last three FCMs have not seen dramatic increases in demand response, which could signal that these resources are reaching their saturation level. In terms of historic performance, demand response resources reduced actual peak demand by just under 600 MW for 2010 as reported by ISO-NE and decreased energy consumption by 4,200 GWh. The reduction in peak demand due to demand resources has ranged from 0 MW in 2004 to 714 MW in 2009.

2.3.2 Energy Efficiency

The demand forecast incorporates the expected effects of federal energy efficiency standards for appliances and commercial equipment that will go into effect in 2013 and historical energy efficiency savings. The forecasts of the energy savings attributable to federal appliance standards and FCM passive resources are 1.6 percent and 4.7 percent, respectively.[5] These represent a total energy savings of 6.3 percent of the gross consumption of electric energy projected for 2020.[6] The state-sponsored energy efficiency resources that participate in the FCM are not captured in the New England load forecasts of the annual and peak use of electric energy because they are treated as capacity resources in planning studies. However, the ISO's load forecast does capture the historical impacts of naturally occurring energy efficiency and the savings resulting from future federal appliance standards.

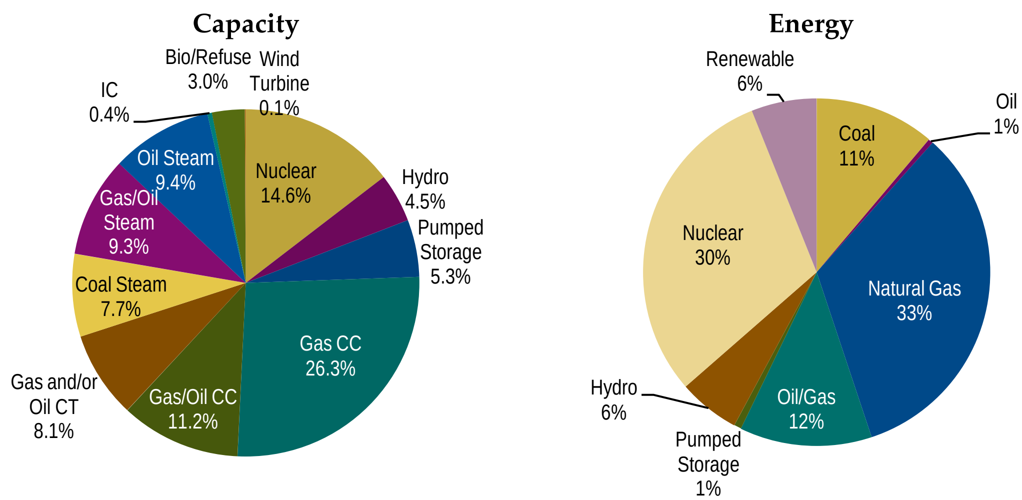
2.4 Generation Resources

For summer 2012, the New England market includes approximately 28,000 MW of generation capacity, 2,600 MW of demand response resources, and 1,600 MW of capacity imports, totaling 32,840 MW. New England has a diverse generation fuel mix with natural gas and dual fuel oil/natural gas capacity holding virtually equal shares and collectively making up just under half of the capacity in the market. Many of the dual-fueled generators capable of burning either oil or natural gas operate primarily on natural gas. In most cases, environmental restrictions on emissions from burning oil greatly limit the total number of hours per year a generator can operate on oil. The percentage of total generation produced by natural gas in New England was 43 percent in 2009. By comparison, about 21 percent of energy was produced by power plants fueled by natural gas nationwide. Oil-fired generation amounts to 13 percent of capacity, but only 1 percent of generation. Many of these older plants are only kept in service due to revenue from the capacity market. Nuclear generation, on the other hand, makes up only 13 percent of the capacity, but provides 31 percent of the energy due to its low variable cost. The 2010 capacity and energy by fuel type for the generation located in the region are shown in Figure 2-2. Not shown are net imports, which accounted for approximately 1,200 MW of capacity and 9,377 GWh of energy in 2010.

[5] *Passive* demand resources are principally designed to save electric energy use and are in place at all times without requiring direction from the ISO. *Active* demand resources reduce load in response to a request from the ISO to do so for system reliability reasons or in response to a price signal.

[6] The ISO's *Forecast Data 2011* (May 5, 2011), sheet 9 (http://www.iso-ne.com/trans/celt/fsct_detail/index.html) shows that the gross consumption of electric energy for 2020 is 151,498 GWh. The savings attributable to federal appliance standards is 2,253 GWh for 2020. In addition, passive demand resources are projected to save 7,194 GWh.

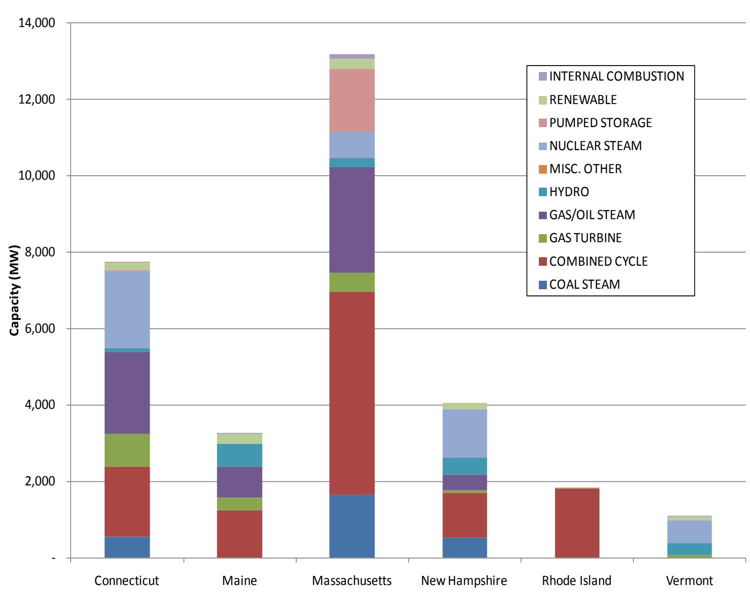
Figure 2-2. Summary of Capacity and Energy by Fuel Type for 2010



Source: ISO-NE, Navigant

The majority of New England's generation assets are located in Massachusetts and Connecticut with most of these resources being natural gas and oil fired and totaling over 20,000 MW. Hydro resources are predominantly located in Maine, New Hampshire, and Vermont.

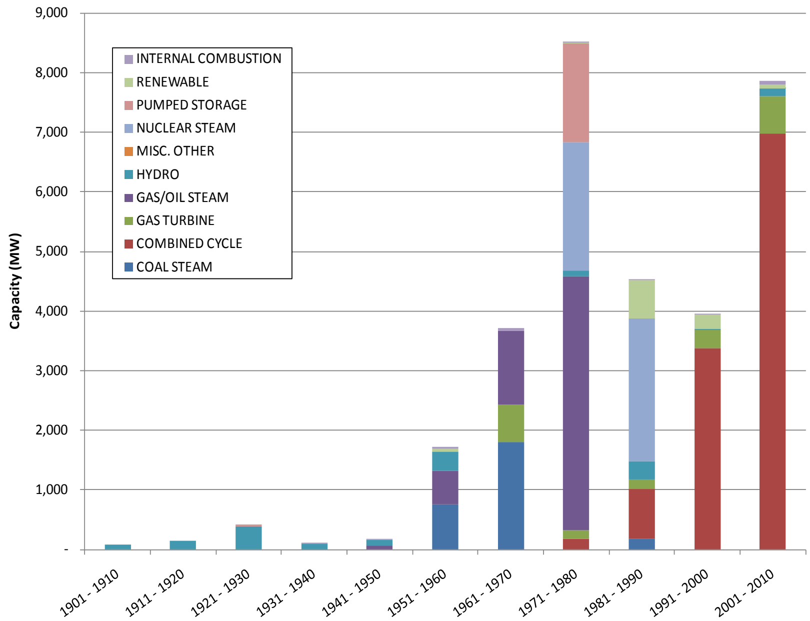
Figure 2-3. Summary of Capacity by Fuel Type and Location



Source: Energy Velocity

About half of the generation assets located in New England are over 30-years old, including about 6,300 MW that are older than 40-years. Almost 7,000 MW of natural gas combined cycle capacity is less than 10-years old. This segment is over 22% of the entire New England generation portfolio. The coal capacity in New England is between 40 and 60 years old. It is estimated that there is between 2,000 MW and 4,000 MW of capacity that will require additional capital investment to meet increased air quality standards. Based on current market conditions, many of these are considered candidates for retirement.

Figure 2-4. Net Summer Capacity by Age and Fuel Type



Source: Energy Velocity

2.4.1 Generation Retirements

There have been minimal announced retirements impacting New England's generation fleet. A plant seeking to retire must submit a permanent delist bid to the ISO to opt out of participating in the upcoming FCM. Once the permanent delist bid is submitted, a study process is triggered whereby the ISO-NE studies the impact of the proposed retirement on the system to make sure the loss of the generation resource will not have an adverse impact on the reliability of the system. A bid that is rejected for reliability reasons will be paid a just and reasonable price, as determined by FERC, for as long as the resource is required to remain in the marketplace.

In 2010, the Salem Harbor Station, located north of Boston in Massachusetts and representing 745 MW of coal capacity, submitted a permanent delist bid for the retirement of all four units. In May 2011, the ISO informed Dominion that it had accepted those bids for the retirement of Units 1 and 2, but rejected the non-price retirement bids for Units 3 and 4 because they were needed for system reliability during the upcoming forward capacity auction (FCA) commitment period. However, transmission infrastructure improvements are being developed, and we expect Units 3 and 4 to be retired by June 2014.

2.4.2 Impacts of Environmental Regulations

There are several uncertainties that could significantly reduce the reserve margin more quickly than anticipated. One is the elimination of the capacity price floor. Another is pending environmental legislation. There are currently three environmental regulations that could impact New England's supply mix and the demand for renewable generation.

- **Maximum Achievable Control Technology (MACT):** In 2011 the Environmental Protection Agency (EPA) proposed revisions to the emissions standards for hazardous air pollutants (HAP) from coal and oil-fired electric generating plants. These revisions are designed to limit HAP, most notably, for mercury and acid gases, based on current MACT. Existing units have up to 3 years to comply with MACT; with individual states granting up to an additional year for facilities to install the necessary emission control equipment. The air toxics rule could impact oil units in addition to coal units.
- **Cooling Water Intake Rules (Clean Water Act Section 316b):** Policy is currently being developed to regulate the use of cooling water for existing power plants. The proposed policy calls for the use of wet, closed-cycle cooling systems (cooling water is re-circulated through cooling towers or ponds and not released into the water system from which it was originally taken) at existing generating facilities that currently use open-loop cooling (cooling water from a river, lake or ocean is used for cooling and released back into the body of water). These regulations are designed to reduce fish entrainment and impingement caused by the use of cooling water by industrial facilities and electric generation plants. As with the air toxics rule, compliance will have a timeline stretching into the second half of the decade.
- **Cross State Air Pollution Rule (CSAPR):** On July 7, 2011, the EPA released the Cross State Air Pollution Rule, which limits emissions of NOx, SO2 and ozone that contribute to pollution in states that are downwind. The modeling completed for CSAPR determined that none of the New England states had a significant adverse impact on the air quality of neighboring states and as a result, they were not subject to emissions reductions under CSAPR. On Dec. 30, 2011 CSAPR was stayed due to a number of challenges, including a challenge to the validity of the modeling. Although not currently expected, there is a low probability that revisions to CSAPR could impact the New England states at a future date. On August 21, 2012, the U.S. Court of Appeals for the D.C. Circuit vacated CSAPR. However, Navigant believes this action is unlikely to notably slow the pace of coal plant retirements as a significant portion of retirements are due to stricter environmental regulations under MACT and low natural gas prices.

The ISO has provided a review in several modeling assessments and reports that evaluated the impact of upcoming EPA regulations and identified fossil and steam thermal units that would need to comply with these regulations. Drawing on these studies and conducting an independent analysis, the ISO identified that the majority of coal generation in New England is at or near compliance levels with the rules, but most liquid oil fired capacity lacks pollution controls to meet the regulation. ISO-NE estimated that the air toxics rule could impact up to 3.6 GW of oil and coal capacity. In addition, 5.6 GW of fossil fuel and nuclear capacity could be subject to more restrictive requirements associated with entrainment mortality and control options under the requirements of the cooling water rules. Even though much of this capacity will remain in service, many of the older steam gas and oil units will be at risk of retirement given their limited operation.

Regional Greenhouse Gas Initiative: The six New England states all participate in Regional Greenhouse Gas Initiative (RGGI), a carbon cap and trade program that covers nine Northeast states. Currently, RGGI auctions and secondary markets have resulted in prices around $2/ton-$3/ton for CO2 allowances – too low to have a meaningful impact on the energy market. Given that federal CO2 programs have stalled, it is unlikely carbon offset prices will increase significantly in the short to medium term.

Key Takeaway: The investment required for complying with some or all of the forthcoming environmental regulations could make a number of the older steam gas and oil units uneconomic and at the risk of retirement given their limited operation.

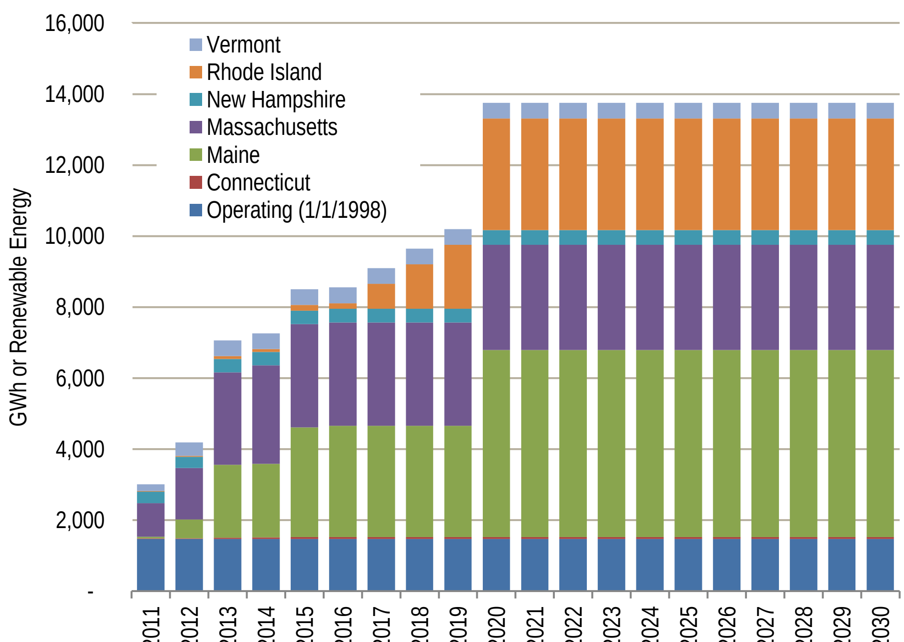
2.4.3 Renewable Resource Development

New England currently less than 500 MW of wind capacity in operation, with a significant amount of renewable resources imported for meeting RPS requirements. There have been a significant number of renewable energy projects proposed over the last several years. However, with low fuel prices and the expiration of the Production Tax Credit (PTC), many of these projects have been cancelled or put on hold until market conditions change.

There is currently over 2,200 MW of wind capacity in the ISO-NE transmission interconnection queue, with half of the resources proposed for Maine and the remaining proposed for New Hampshire, Vermont, and Massachusetts. The wind under development in Massachusetts includes almost entirely the Cape Wind project. Many of these resources are dependent on transmission infrastructure development for their successful fruition.

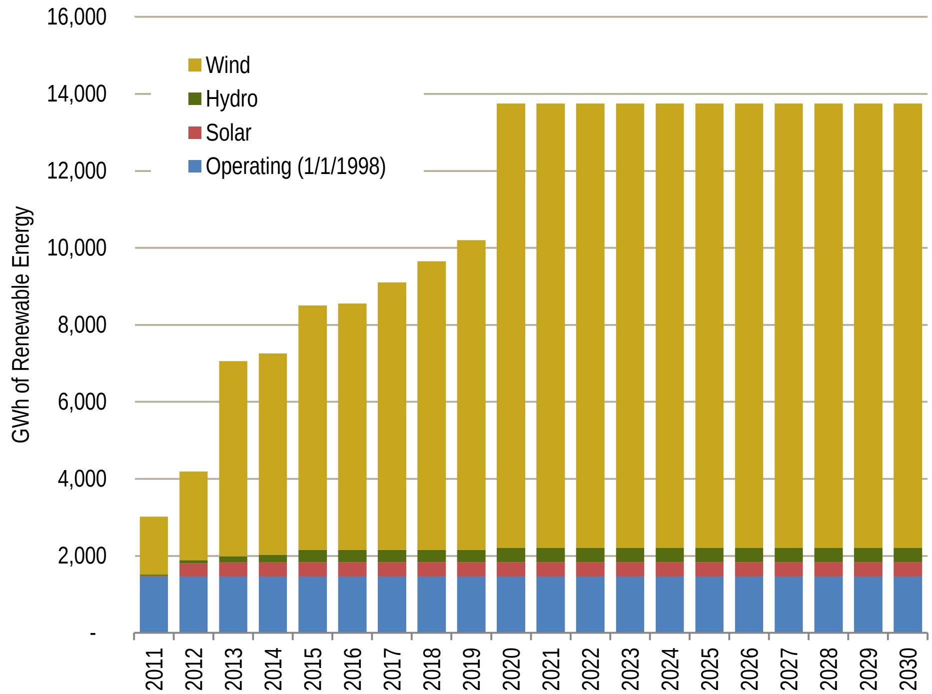
Figure 2-5 provides a summary of the renewable energy development in New England. This data is based on the information contained in the transmission interconnection queue process. Figure 2-6 presents the same information, presented by fuel type. As can be seen from both these charts, wind project are a significant source of planned renewable resources in the region.

Figure 2-5. Renewable Energy Development by State



Source: Energy Velocity, Navigant

Figure 2-6. Renewable Energy Development by Fuel Type



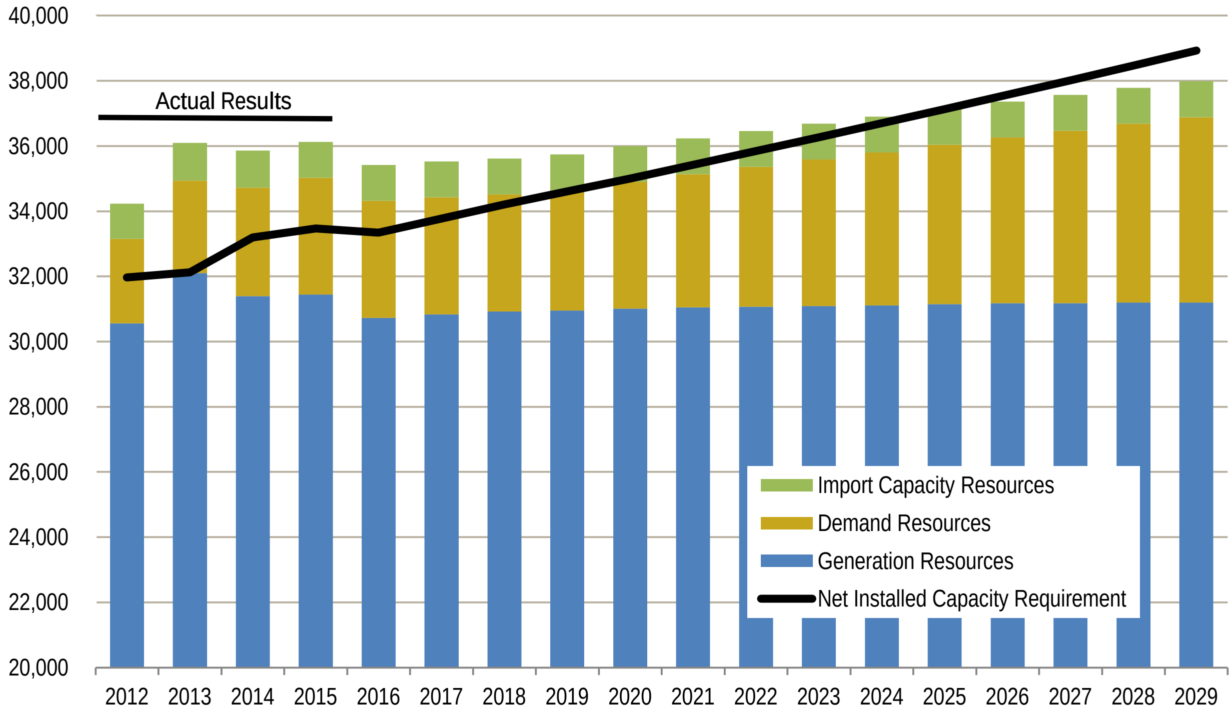
Source: Energy Velocity, Navigant

2.5 *Supply-Demand Balance*

As described above, ISO-NE implements a FCA for the procurement of capacity resources three years in advance of the delivery year. Generators and demand response resources compete for a capacity obligation, offering into the market during the descending-clock auction process. Under current rules, the FCM includes a floor price; when the auction price as set by the bidders descends to the floor price that auction is stopped and all capacity in the market receives a prorated capacity payment. There have been five auctions held so far, each one stopped when the auction price met the floor price, which has resulted in 2,000-5,000 MW of surplus capacity in the market. In the latest auction, for delivery year 2014/2015, there is over 4,000 MW of surplus capacity in the market. Under current rules, the floor price is set to terminate after the 2015/2016 auction. This is anticipated to result in extremely low prices that could result in some capacity permanently delisting (retiring) in the market.

Based on a forecast of peak demand, demand response and generation resources, and using reasonable assumptions on imports and other parameters, a projection of capacity requirements can be constructed for the New England market. Navigant has constructed such an analysis using forecasts and other information from ISO-NE and other assumptions. In constructing this forecast, we have taken a conservative approach related to incremental generation development and demand response resources. We include the recently announced retirement of Salem Harbor Station, and include 1,100 MW in imports which is consistent with the level of imported capacity from past auction results. Figure 2-7 presents a comparison of the net installed capacity requirements to the total resources and imports in the market. This assessment illustrated the significant amount of capacity that currently exists in the market, above the net installed capacity requirement. Based on this simple assessment, the New England market may not need additional capacity until between 2020 and 2025 depending on the availability of capacity imports and decisions on future retirements.

Figure 2-7. Supply-Demand Forecast for New England



Source: ISO-NE, Navigant

As can be seen from Figure 2-7, the market has the potential to remain surplus for the next 8 to 10-years, unless there are generation retirements or a reduction in imports.

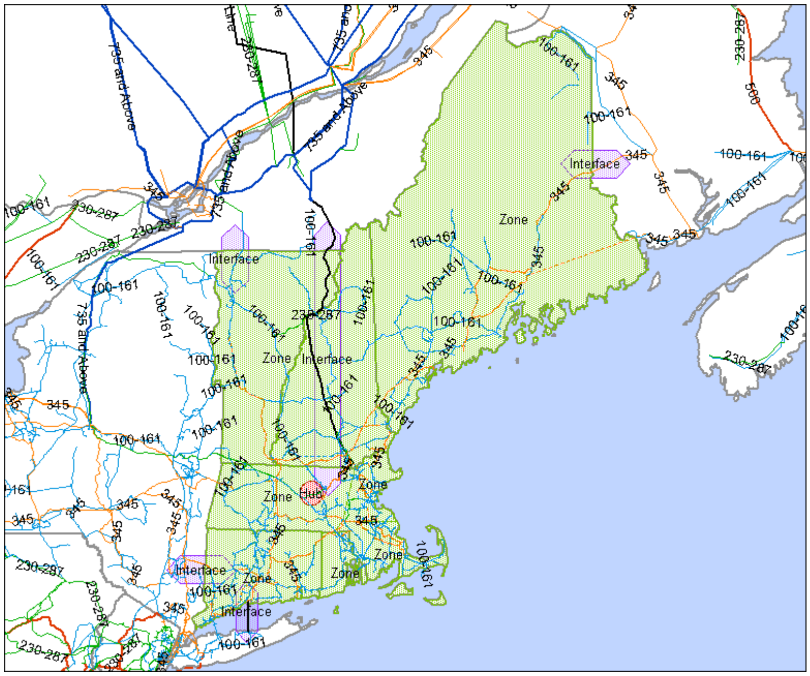
2.6 Transmission System

As the RTO for New England, ISO-NE is responsible for oversight of the region's transmission system, which currently includes 8,000 miles of transmission lines composed mostly of 115 kV, 230 kV, and 345 kV circuits. In addition to the transmission infrastructure within the region, New England has transmission interfaces with New Brunswick, Quebec, and New York.

- New England and New Brunswick are connected through two 345 kV ties (1,000 MW);
- New England has two high-voltage direct-current (HVDC) interconnections with Quebec: a 225 MW back-to-back converter at Highgate in northern Vermont and a +/– 450 kV HVDC line with terminal configurations that allow up to a 2,000 MW delivery at Sandy Pond in Massachusetts; and
- There are nine interconnections with New York: two 345 kV ties, one 230 kV tie, one 138 kV tie, three 115 kV ties, one 69 kV, and one 330 MW HVDC tie between Connecticut and Long Island.

Figure 2-8 provides a map of the highlights the region's transmission infrastructure and the system interconnects with three other regions: New York, Quebec, and New Brunswick. Currently, import capability to ISO-NE is approximately 4,200 MW[7].

Figure 2-8. New England Transmission System and Interfaces with Neighboring Regions

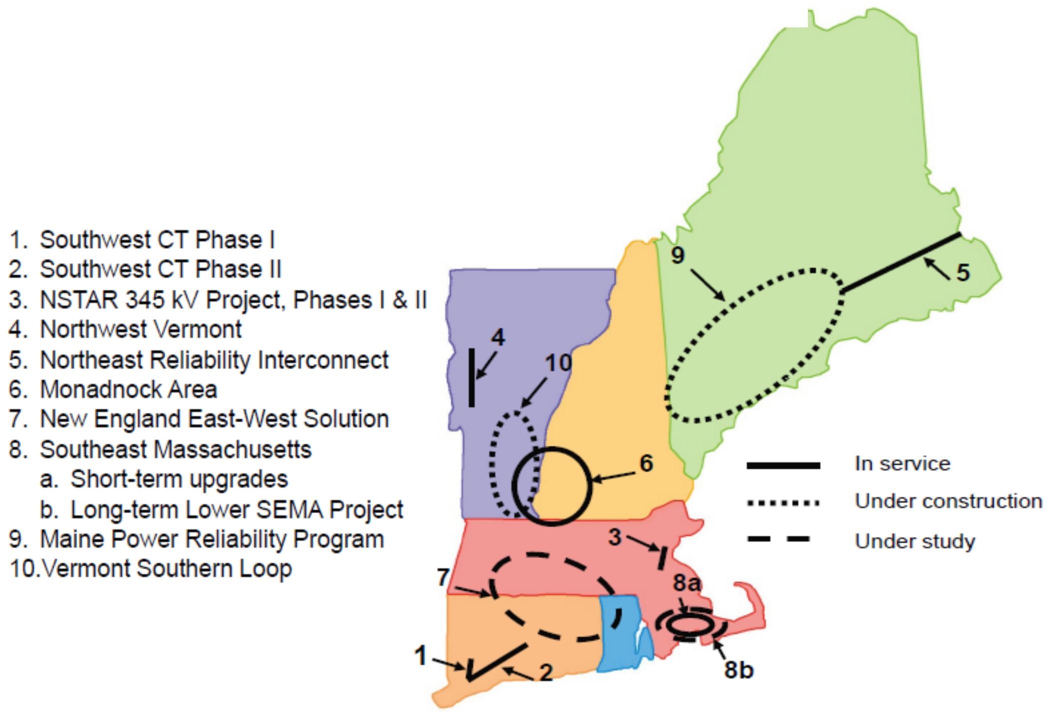


Source: Energy Velocity

New England's transmission owners have constructed a total of 341 transmission projects, representing $4.3 billion in new infrastructure investment from 2002 to 2010. An additional $5 billion of investment is still underway or planned. Fourteen of the projects are major 345 kV transmission lines that have been identified as critical for maintaining transmission system reliability. The location of these projects is shown in Figure 2-9. Eight of those projects are already complete — phases 1 and 2 of the Southwest Connecticut Reliability Projects; the Northeast Reliability Interconnection Project; phases 1 and 2 of the Boston Transmission Reliability Project; the Short-Term Lower South-East Massachusetts (SEMA) Upgrades, the Northwest Vermont Reliability Project, and the Vermont Southern Loop.

[7] Sum of Total Transmission Capability, TTC, as reported by the ISO-NE for noon on November 29, 2006

Figure 2-9. ISO-NE Completed and Proposed Transmission Projects



Source: ISO-NE 2011Regional System Plan

There are a number of projects that are currently under development or being planned by either ISO-NE or market participants. Relevant projects to the AEG initiative are discussed in more detail below

2.6.1 Northeast Reliability Interconnection

The Northeast Reliability Interconnection (NRI) is a 144-mile, 345 kV transmission line connecting New Brunswick, Canada to Orrington, Maine. This line increases transfer capability from New Brunswick to New England by 300 MW. The Northwest Vermont Reliability Project is composed of a series of 345 kV and 115 kV transmission lines intended to address system reliability in the northwestern area of Vermont and the Vermont Southern Loop and will address significant system performance concerns for key contingencies occurring under heavy import conditions. The substation involves installing a new Vernon–Newfane–Coolidge 345 kV line with several 345/115 kV substation upgrades. This project was completed in early 2011.

2.6.2 The Maine Power Reliability Program

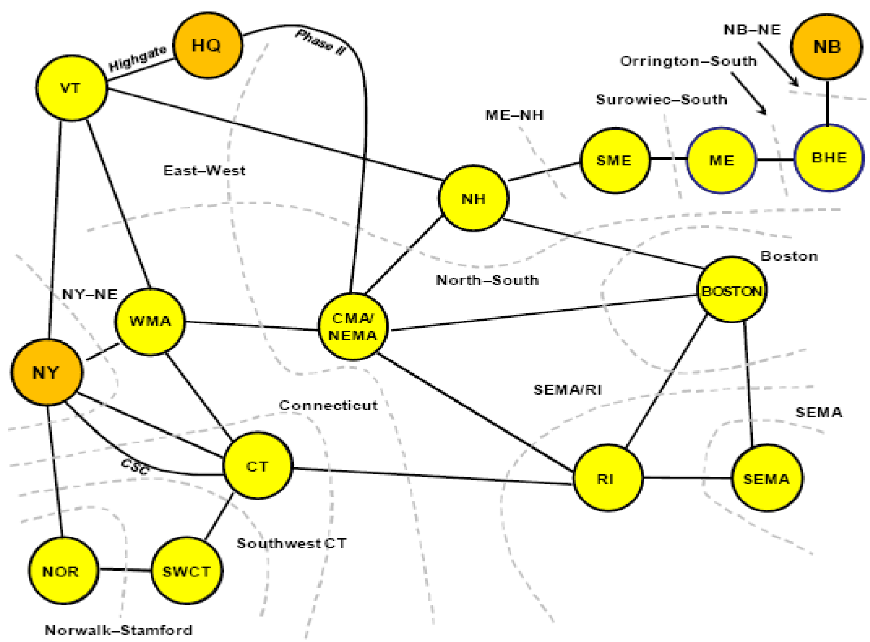
Central Maine Power (CMP) has identified several transmission upgrades required to alleviate load pockets and increase the ability to move power into Maine from New Hampshire and improve the ability of the transmission system within Maine. The Maine Power Reliability Program (MPRP) includes the construction of approximately 500 miles of new or upgraded transmission lines, largely in CMP's existing transmission corridors, plus four new 345 kV substations and related facilities. The MPRP was conditionally approved in May 2010 by the Maine Public Utilities Commission (MPUC), and upgrades are planned to be phased in over a number of years. Although ISO-NE is still performing stability studies, this project is estimated to increase the interface limit between Maine and New Hampshire by about 150 MW.[8] The expansion of this interface is critical for facilitating power sales from Maine and into the rest of New England. This project is also estimated to reduce congestion costs in Maine.

2.6.3 Northern Pass HVDC Line

The proposed Northern Pass transmission line, an HVDC line being proposed from southern Quebec to southern New Hampshire (not shown on map) is being proposed to import 1,200-1,500 MW from Hydro Quebec. This project is still in the planning phases but may have a significant impact on energy prices and congestion in Southern New Hampshire and Vermont, and the ISO-NE FCM.

Important considerations for exports from New Brunswick to New England are 1) the capability of the transmission system at the interface and 2) the capability of the transmission system in Maine to move the power to the load centers south of the North-South Interface. This second limitation on the transmission has been a noted constraint on the system, especially between Maine and neighboring New Hampshire. There has been a significant amount of generation capacity developed in Maine over the last decade, primarily due to its access to Canadian natural gas and available and suitable sites. This significant generation, coupled with a minimal local load growth has caused an export constraint in Maine. The export constraint has led to lower capacity clearing prices in each of the FCA. Figure 2-10 provides a "bubble" representation of the transmission system in New England.

Figure 2-10. Transmission Representation for New England



Source: ISO-NE

The existing interface limits are as follows: New Brunswick–New England; 1,000 MW[9]; Orrington–South Export 1,200 MW; Surowiec–South 1,150 MW; and Maine–New Hampshire 1,600 MW. Additionally,

[8] See ISO-NE's filing to FERC in Docket No. ER12-757-000, dated February 13, 2012.

since the MPRP falls within Maine and serves to increase the reliability of the Maine system, this project is not anticipated to significantly increase the capability of the system for exports from Maine to New Hampshire.

Key Takeaway: Maine is currently export constrained, with an abundance of natural gas-fired generation capacity. This has led to low energy prices, lower capacity prices, and reliability issues. The proposed transmission projects are being developed to address reliability concerns, and do not explicitly address the export constraint between Maine and New Hampshire.

2.7 Markets

ISO-NE operates energy, capacity, and ancillary service markets. Energy prices are determined on a nodal and zonal base; generators are paid the nodal price, reflecting the point of interconnection to the system, and load pays the zonal price, calculated as the load-weighted nodal price within the zone. ISO-NE operates two energy markets, a day-ahead and real-time market. The day-ahead market is financially binding where offers and bids are accepted the day before the operating day. The day-ahead market is simulated to determine a least-cost dispatch for the resources bidding into the market. The ISO also operates a real-time market to account for any unexpected changes to the day-ahead schedule. ISO-NE also manages the FCM. Through the FCA, resources are procured on an annual basis for three years in advance to create price and revenue certainty for new resources. Table 2-1 provides a summary of the competitive markets managed by ISO-NE for New England.

Table 2-1. Description of the ISO-NE Markets

Energy	**Day-ahead Energy Market**	• Forward market in which hourly LMPs are calculated for the next operating day based on generation offers, demand bids and scheduled bilateral transactions.
	Real-time Energy Market	• Spot market in which current LMPs are calculated at five-minute intervals based on actual grid operating conditions.
Capacity	**Forward Capacity Market (FCM)**	• Compensates generators and demand response resources for future capacity commitments. Provides efficient long-term market signals to govern decisions to invest in new generation and demand resources and to maintain existing resources.
Ancillary Services	**Regulation Market**	• Compensates resources that are instructed to increase or decrease output instantaneously to balance the variations in demand and system frequency.
	Forward Reserve Market (FRM)	• Compensates generators for the availability of their unloaded operating capacity that can be converted into energy within 10 or 30 minutes when needed to meet system contingencies.
	Real-time Reserve Pricing	• A mechanism used to implement scarcity pricing, which compensates on-line generators above the marginal cost of electric energy for the increased value of their energy when the system or portions of the system are short of reserves.
Transmission Market	**Financial Transmission Rights (FTR)**	• Used to hedge against the economic impacts associated with transmission congestion and provides a financial instrument to arbitrage differences between expected and actual day-ahead congestion.

Source: ISO-NE, Navigant

[9] For capacity purposes, ISO-NE has assumed this value to be 1,000 MW for the next several Forward Capacity Auctions, through 2013/2014. Beginning in 2014/2015, ISO-NE is giving this interface capacity value of 700 MW thereafter.

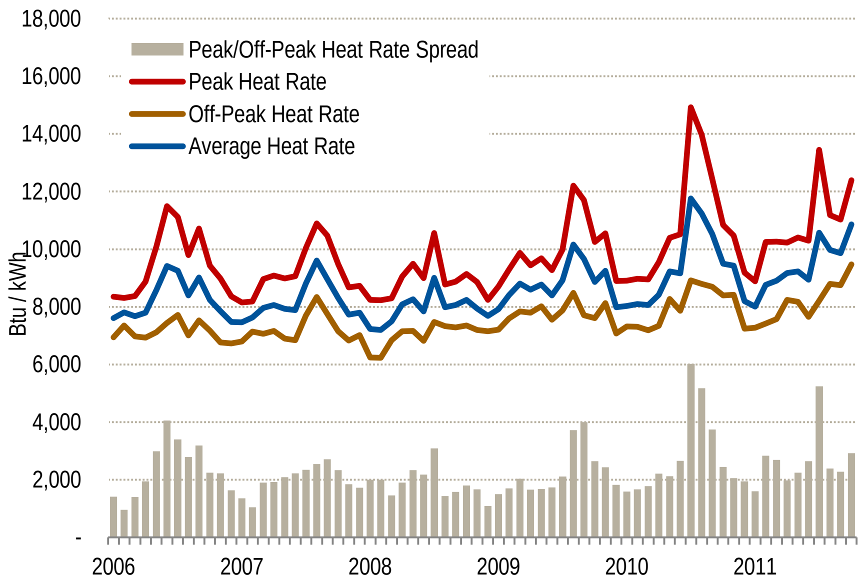
2.7.1 Energy Market

ISO-NE has a nodal market structure. In a nodal market, the LMP is determined at thousands of nodes across New England, highlighting transmission congested areas. Higher marginal cost generators will need to be used in load pockets because lower cost power cannot be brought to the load at a sufficient level during times of transmission congestion. This provides incentives for generators to site close to load or in constrained areas of the transmission system. LMPs are generally higher in the southern parts of ISO-NE, primarily the Boston area and Connecticut, but due to the recent transmission upgrades and new generation additions, the price differentials across New England are relatively small (generally less than $1/MWh difference between most nodes and Mass Hub).

Generator operation in New England can either be dispatched by the ISO-NE or be self-scheduled to meet the obligations of the market participant. Generators that are dispatched are done so around the self-scheduled resources. Dispatchable resources serve between 20 and 30 percent of the energy requirements in a typical month, with self-scheduled resources not controlled by the ISO-NE meeting the remaining monthly energy requirements.

As a measure of the efficiency of the energy market, the implied market heat rate provides a simple way of studying market trends where a simple analysis of energy prices can be misleading. The historical market heat rate for New England has been consistent, reflecting natural gas on the margin with oil and demand response for peaking as can be seen in Figure 2-11. Energy prices are based on the Boston zonal price for the day-ahead market and natural gas prices are based on Algonquin City Gate. The heat rate consistently peaks in the July and August around 11,000 to 12,000 Btu/kWh. ISO-NE's energy prices are driven predominantly by natural gas prices, since natural gas-fired generation is on the margin over 70% of the hours in the year. The New England system's market heat rate appears to be stable, exhibiting a diurnal and seasonal shape that has averaged about 8,600 Btu/kWh over the last five years. At a natural gas price of $5.00/MMBtu, wholesale electricity market prices would be about $43 MWh. The 2011 market heat rate did not follow the previous years' trend. In June 2011 New England experienced a heat wave where emergency purchases from neighboring regions and 600 MW of demand response were needed to meet operating reserve requirements.

Figure 2-11. New England Historical Market Heat Rate



Source: Navigant

Key Takeaway: NE historical market heat rate has averaged 8,600 BTU/kWh over the past several years. At a natural gas price of $5.00/MMBtu, wholesale electricity market prices would be about $43/MWh (USD).

2.7.2 Forward Capacity Market

The ISO-NE administers a FCM to assure that there are sufficient resources available to meet the projected capacity requirements for the system. The FCM allows generators to sell their capacity three years (40 months) ahead through an annual FCA. Capacity can be from new or existing resources including generation, demand resources, and imports. Resources must undergo a "qualification process" to participate in the FCA. Existing resources must demonstrate historic performance for the past five years. New resources can lock in auction clearing prices for up to five years, but must undergo a more rigorous qualification process, demonstrating development feasibility, interconnection reliability impacts, timing for commercially availability, and that they can provide the capacity bid into the auction.

The capacity auctions use a descending-clock format, in which the auction price is lowered in prescribed increments until total offered capacity equals the installed capacity requirement (ICR). Resources enter a dynamic delist bid at which they will withdraw from the auction. When the price drops such the available resources equal the ICR, the auction is stopped and the price that capacity clears the market is established for all capacity resources remaining in the auction process. The starting price of the first auction was set at two times the estimated cost of new entry (CONE). CONE was set at $7.50 per kW-month for FCA1, $6.00 per kW-month for FCA2, and $4.92 per kW-month for FCA3 and FCA4[10]. For

[10] Based on the current market rules, CONE was set at $4.918 per kW-month for FCA4 because there was no need for additional resources in FCA3.

FCA2 and FCA3, CONE was calculated as a function of the clearing price in the preceding auction. For FCA4, CONE was left at the same value as FCA3, and for FCA5 CONE was escalated at the Handy Whitman Index. A floor price is set at 0.6 times CONE to ensure that the resulting market pricing compensated capacity resources.

Another important provision of the market rule is Proration, which occurs when the auction price reaches the floor price in an FCA and the auction is stopped. There are two Proration options available for resources remaining in the auction: maintain the full Capacity Supply Obligation with a reduced payment rate (Price Proration); or receive a reduced Capacity Supply Obligation with the full capacity clearing price (MW Proration). The Proration option chosen by resources does not have an effect on the total amount of money paid by load and received by a resource.

The ICRs are determined based on an assessment of load, resources, and transmission limitations, resulting in a projected capacity requirement for each capacity zone. To calculate the amount of capacity needed in the auction, ISO-NE first subtracts the reliability benefits associated with the Hydro Quebec Phase II Interface. This benefit, called HQ Interconnection Capacity Credit ("HQICC") was 1,400 MW in the first auction and about 900 MW for subsequent FCAs. Based on the current market design, capacity zones with separate supply requirements can be established as they may become necessary due to transmission constraints on the system. Since the first auction, the Maine load zone has been defined as an export constrained zone, due to the transmission limitations between Maine and New Hampshire. Similarly, beginning with FCA7 the Northeast Massachusetts (NEMA) and Connecticut load zones have been defined as import-constrained areas and will be modeled separately.[11] As such, these three zones will likely clear at slightly different prices than the remaining zones.[12]

Results of the first five FCA are presented in Table 2-2. As can be seen, for each of the auctions the Capacity Supply Obligation exceeded the net installed capacity requirement (NICR), resulting in a capacity surplus of between 2,000 and 5,000 MW. The surplus is the result of the auction reaching the floor price and was stopped per auction rules with excess capacity remaining in the auction. Under the rules, all capacity remaining in the auction will receive a Capacity Supply Obligation. As discussed, the winning bidder will be able to take either the prorated payment or the full capacity clearing price with its capacity prorated. As can be seen, the surplus capacity has depressed the clearing price for capacity.

It is important to note that ISO-NE and the NEPOOL participants are currently exploring several market design frameworks that address alternative clearing price structures for the existing New England capacity market. These discussions are taking place as part of confidential settlement discussions. Based on the limited information available on the ISO-NE website, the redesign efforts are exploring a number of options, such as demand curve and mechanisms to reduce price volatility.

[11] See FERC Order ER12-953-000, dated March 30, 2012.

[12] NEPOOL participants are currently evaluating alternative capacity market structures that are designed

Table 2-2. FCA Results

FCA Capacity (MW)	2010-2011	2011-2012	2012-2013	2013-2014	2014-2015
AUCTION INPUT					
Peak Demand Forecast	28,160	28,575	29,020	28,570	29,025
Installed Capacity Requirement (ICR)	33,705	33,439	32,879	33,043	34,154
HQ Interconnection Capacity Credit (HQICC)	1,400	911	914	916	954
Net Installed Capacity Requirement (NICR)	32,305	32,528	31,965	32,127	33,200
AUCTION RESULTS					
Existing Generation Resources	30,239	31,050	30,558	32,103	31,397
Existing Demand Resources	1,366	2,483	2,588	2,834	3,327
Existing Imports	934	769	1,083	1,162	1,140
New Generation Resources	626	1,157	1,670	144	42
New Demand Resources	1,188	448	309	515	263
New Imports	0	1,529	817	831	871
Capacity Supply Obligation	34,077	37,283	36,995	37,589	37,040
Capacity Surplus	2,047	4,755	5,030	5,462	3,718
AUCTION PAYMENT ($/kW-month)					
Capacity Clearing Price	$4.50	$3.60	$2.95	$2.95	$3.21
Prorated Payment Rate	$4.25	$3.12	$2.54	$2.68	$2.88

Source: ISO-NE, Navigant

2.8 *Import and Exports*

New England has consistently been a net importer over the last several years, relying on significant intertie capacity with Canada to import from the north and several smaller interties with southern New York for exports from southern New England. As mentioned above, New England and New Brunswick are connected through two 345 kV ties; the average hourly energy flow is predominantly from New Brunswick to New England. The flow is greater during the on-peak hours. The flows have averaged about 140 MW, annually into New England. There seems to be no consistent pattern for the monthly flows for the 2006-2009 period.

New England has two HVDC interconnections with Quebec: a 225 MW back-to-back converter at Highgate in northern Vermont and a +/– 450 kV HVDC line with terminal configurations that allow up to a 2,000 MW delivery at Sandy Pond in Massachusetts. The average hourly energy flow pattern from HQ is shaped to flow at a higher rate during on-peak hours and less during off-peak hours. Flows from HQ are highest in winter and summer months and decrease in the spring and fall months. Flows have increased from Quebec consistently from 2006-2009 from 6 TWh to 11 TWh.

There are nine interconnections with New York: two 345 kV ties, one 230 kV tie, one 138 kV tie, three 115 kV ties, one 69 kV tie, and one 330 MW HVDC tie between Connecticut and Long Island. Exports to Long Island over the Cross Sound Cable have been almost at the line's full rating of 330 MW during the on-peak periods. An illustrative summary of annual energy imports and exports for 2010 is provided below.

Table 2-3. Electricity Trade with Neighboring Systems - 2010

Interface	Imports (MW)	Exports (MW)	Net (MW)
New Brunswick	1,224	487	737
Keswick	760	180	580
Pt. Lepreau	464	307	157
Hydro Quebec	9,561	347	9,214
Highgate	1,464	38	1,426
Phase II	8,096	309	7,787
New York	1,997	6,408	(4,412)
Cross Sound Cable	0	2,397	(2,396)
AC Ties	1,997	4,011	(2,016)
Total	12,781	7,242	5,539

Source: ISO-NE

Despite the large capacity for imports, most of the transmission import capability from New Brunswick is being used by Hydro Quebec and Boralex for 2013-2015. Transmission capacity between New Brunswick and New England appears limited, with no capacity available in the short term. Hydro Quebec secured fifteen year transmission rights to the 300 MW intertie between New Brunswick and Maine.[13] This will limit the ability for clean and renewable energy from Atlantic Canada to participate in the New England energy and capacity markets in the short term. Table 2-4 illustrates the available and unused transmission capacity between New Brunswick and Maine for the first five FCAs in ISO-NE through 2015. The annual periods are based on the FCA procurement period, from June 1-May 31.

Table 2-4. FCA Results New Brunswick

FCA Assumptions (New Brunswick)	2010-2011	2011-2012	2012-2013	2013-2014	2014-2015
Existing Interface Limits (MW)	1000	1000	1000	1000	700
Tie-Line Benefits (MW)	360	716	609	584	439
Available for Import (MW)	640	284	391	416	261
FCA Auction Results (New Brunswick)	2010-2011	2011-2012	2012-2013	2013-2014	2014-2015
Existing Imported Cleared (MW)	0	0	0	0	0
New Imports Cleared (MW)	0	0	0	366	286
Unused Capacity (MW)	640	284	391	50	-25

Source: ISO-NE, Navigant

[13] Carr, J, *Power Sharing: Developing Inter-Provincial Electricity Trade,* C.D. Howe Institute Commentary, pg. 10, available online: http://www.cdhowe.org/pdf/commentary_306.pdf

Looking beyond 2015 to the 2017/18 expected in-service date for the proposed Muskrat Falls hydroelectric project, Nalcor has secured access through Nova Scotia and New Brunswick into the New England markets through various transmission service, access and rights agreements with Emera. These agreements were among thirteen agreements that Nalcor and Emera executed on July 31, 2012[14] related to the Muskrat Falls and associated HVdc transmission (Labrador-Island Link and Maritime Link) projects. In combination with the transmission access it currently has through Quebec, these agreements will allow Nalcor to sell any available energy and capacity into the New England energy market that is not utilized by Nalcor or committed for delivery into Nova Scotia. If the electricity available from Nalcor is eligible to participate in any of the state REC markets, it would also be able to access these markets.

[14] The agreements are available at: http://www.nalcorenergy.com/formal-agreements.asp

3. Export Opportunities for Clean and Renewable Energy to New England

As discussed in the previous section, there are three distinct "markets" for clean and renewable energy in New England: 1) the New England energy market; 2) the New England capacity market; and 3) the various state Renewable Energy Credit (REC) markets. Generally speaking, the energy market is accessible to any supplier that can physically deliver electricity into New England and, similarly, the New England capacity market is accessible to any supplier with a firm transmission path into New England.[15] The rules for the individual state REC markets vary from state to state depending on each state's Renewable Portfolio Standard (RPS), particularly with respect to the type of renewable energy that is eligible to participate in the market.

The energy and capacity market demand and supply dynamics for clean energy in New England are distinct and different than those for the REC markets for renewable energy in New England. In this section we will review the demand and supply drivers for each separately. The potential for clean energy exports from Atlantic Canada that would sell into the New England energy and capacity markets include nuclear and large hydro power. Unlike some types of renewable resources, there is no legislative requirement in New England to procure energy from either of these fuel types. Therefore, the demand for clean energy in New England is dictated by the prevailing demand and supply dynamics in the ISO New England administered market. Clean energy exports from Atlantic Canada compete with all other fuel types in the market. Currently, New England has sufficient supply to serve its demand and is expected to have sufficient capacity and energy for the next 10-20 years, or short to medium term based on the most recent FCM auction.

The New England REC opportunities are driven by state level RPS requirements. These legislative requirements oblige utilities and load serving entities to supply a certain percentage of their energy demand with RPS compliant renewable generation. The legislation also generally requires physical delivery of the renewable energy into New England, so renewable energy exports will generally need to sell into the New England energy market in order to access the REC markets, and could potentially access all three of the New England markets (energy, capacity and RECs) depending on the nature and firmness of capacity offered by the renewable energy source.

The types of renewable generation that comply towards RPS requirements vary slightly by state. For example, some do not include large-scale hydro to count towards RPS compliance, while others allow it. The extent to which states within New England are short on renewable energy to satisfy their RPS compliance targets will dictate the size of the export opportunity for renewable energy from Atlantic Canada.

Although the demand drivers for clean and renewable energy exports from Atlantic Canada vary, there are at least two common limitations: transmission capacity and competition from both in-region and out-of-region resources. The transmission path from Atlantic Canada to New England runs through New Brunswick to Maine then further south into the rest of the New England. Limitations throughout the

[15] While not a requirement, a firm transmission path for renewable resources participating in the New England REC market may be a prudent business decision depending on any delivery shortfall charges or other penalties associated with not fulfilling specific contractual obligations for the sale of RECs.

transmission system, like those currently experienced in northeastern Maine, will tend to depress prices for deliveries of clean and renewable exports into Maine as compared to prices in ISO-NE's load centres in the south, such as around Boston. Competition from proposed projects in New England as well as exports from Quebec and New York will compete with generation coming from Atlantic Canada, both on the clean and renewable side.

This section of the report provides an update on the demand and supply for clean energy, followed by a similar discussion on the demand and supply for renewable energy.

3.1 Clean Energy

As described above, there is no formal or legislated distinction within any of the New England states between clean energy, as defined as large-scale hydro and nuclear power, and more polluting forms of power including coal or oil fired steam generation. The demand for clean energy is driven by the New England electricity market demand and supply fundamentals, and will compete with all forms of electricity on a cost basis. However, these demand and supply fundamentals are influenced by ISO-NE market rules evolution and federal environmental regulations. This section provides an overview of each state's position towards nuclear and large hydro, as well as the developments of new out-of-region capacity in Quebec.

3.1.1 Demand for Clean Energy

Each state has a varying degree of receptiveness towards electricity generated from large-scale hydro and nuclear sources. This section describes each state's objectives and outlooks as presented their state energy plans and other state objectives.

1. **Vermont:** In Vermont, nuclear is a contentious issue – there is a pending lawsuit to determine if a nuclear plant should be closed by March 2012.[16] Vermont's Comprehensive Energy Plan (CEP) states that utilities should plan for alternative supply sources, including out-of-state nuclear. While no specific clean energy provisions exist, Vermont does allow large-scale hydro to count towards its 90% renewable energy target by 2050.
2. **Connecticut:** Connecticut has a moratorium on the siting and construction of new nuclear generating facilities until the issues concerning the disposal of high level nuclear waste have been resolved. Furthermore, the state budget includes a tax of $2.50 / MWh on fossil and nuclear generation effective July 1, 2011 to June 30, 2013.
3. **Maine:** The State of Maine Comprehensive Energy Plan 2008–2009 demonstrates it is receptive to electricity imports from Atlantic Canada. In regard to transmission investment and improved coordination with the Eastern Canadian Provinces (including Quebec), the Energy Plan states that the ISO New England and its stakeholders are discussing bringing additional renewable and non-carbon emitting (such as nuclear) into the ISO New England energy portfolio.
4. **Massachusetts:** The Massachusetts Clean Energy and Climate Plan for 2020 (CECP) plans for more stringent EPA power plant rules and clean energy imports. This plan also notes that a new transmission line connection with Hydro Quebec will provide up to 15% of the state's electricity

[16] Vermont Department of Public Service, *Comprehensive Energy Plan 2011*, pg. 150, available on line: http://www.vtenergyplan.vermont.gov/sites/cep/files/Vol%202%20Public%20Review%20Draft%202011%20CEP.pdf

demand when it is complete.[17] The report also suggests that a Clean Energy Performance Standard could be developed to encourage increased imports. However, this policy idea is built on the premise that: "*Canada has substantial hydroelectric resources, which have very low emissions, and are available at relatively low cost and with no need for renewable energy subsidies.*"[18] Recently, the Massachusetts Green Communities Act, which establishes policies and goals for renewable and alternative energy and energy efficiency was amended to allow hydroelectric power, regardless of whether that power is eligible under the renewable energy portfolio standard, for meeting the state's previous goal of at least 20 percent of the Commonwealth's electric load by the year 2020 through new, renewable and alternative energy generation.

5. **New Hampshire:** New Hampshire has no explicit policy on the development or use of large-scale hydro, outside of its RPS legislation, which does not allow it to count towards its target. See Table 3-1 for more information. It does have an operating nuclear power plant that it anticipates to continue to operate to 2020.

6. **Rhode Island:** The majority of the electricity used in Rhode Island comes from out-of-state, with nuclear power representing 27.5% of power consumed.[19] RI's vision statement included in its March 2011 planning document is "*In 20 years, energy in Rhode Island will be more efficient, reliable, and secure and at least 30% of all energy used in the State will come from clean and renewable resources, with at least 20% of the total coming from within the State.*" Given the current level of imports, limited inside state generating capacity and target for future imports, RI is a state that is receptive to clean energy imports.

Based on our review of the state energy plans and other regional and state-level objectives, Table 3-1 summarizes the northeast states' perceived receptiveness towards nuclear and large-scale hydro imports.

Table 3-1. Receptiveness towards Clean Energy Imports

State	Nuclear	Large Hydro
Vermont	+/-	+
Connecticut	-	+/-
Maine	+	+
Massachusetts	+	+
Rhode Island	+	+
New Hampshire	+/-	+

Source: Navigant

[17] Massachusetts Clean Energy and Climate Plan, page 45, available on line: http://www.greenneedham.org/blog/wp-content/uploads/2011/02/2020-clean-energy-plan.pdf
[18] Ibid.
[19] Rhode Island Government Technical Committee Presentation, *RI Energy Plan (Update) and The Renewable Energy Siting Guidelines & Standards,* March 4, 2011, available on line: http://www.planning.ri.gov/landuse/Energy%20plan311.pdf

3.1.2 Out-of-Region Supply – Quebec

Quebec's market is dominated by Hydro Quebec a vertically integrated provincially owned corporation that includes three primary divisions: Hydro Quebec Distribution, the division that is responsible for operating Quebec's distribution system and ensuring there is sufficient supply to satisfy indigenous electricity demand; Hydro Quebec Production (HQP), which operates its generating assets including 34,500 MW of hydro, 675 MW of nuclear and 1,500 MW of thermal resources; and Hydro Quebec Transenergie, the division which operates and manages its bulk transmission system. Although they report their activities separately, these divisions operate collectively to maximize value for their common shareholder and to facilitate provincial government policy objectives.

Hydro Quebec's *Strategic Plan 2009 – 2013* includes increasing energy exports as one its strategic objectives for HQP, and has a number of hydroelectric expansion and infrastructure investments underway to support that objective.

1. **HQP's Major Projects:** One of the objectives identified in Hydro Quebec's *Strategic Plan 2009 – 2013* was the increase in Hydro Generating Capacity. The plan called for an increase of 1,000 MW of new capacity between 2008 and 2013, representing 8.7 TWh of new energy. The breakdown of new energy and capacity is provided in Table 3-2.

Table 3-2. Hydro Quebec Major Projects

Project	Energy (TWh)	Capacity (MW)	Commissioning
Construction: Eastmain-1-A/Sarcelle/Rupert	8.7	918	2009 - 2012
Refitting (capacity gains) La Tuque		38	2008 - 2009
Total – 2013	8.7	956	
Romaine Complex	8.0	1,550	2014 – 2020
Total – 2020 Horizon	16.7	2,506	

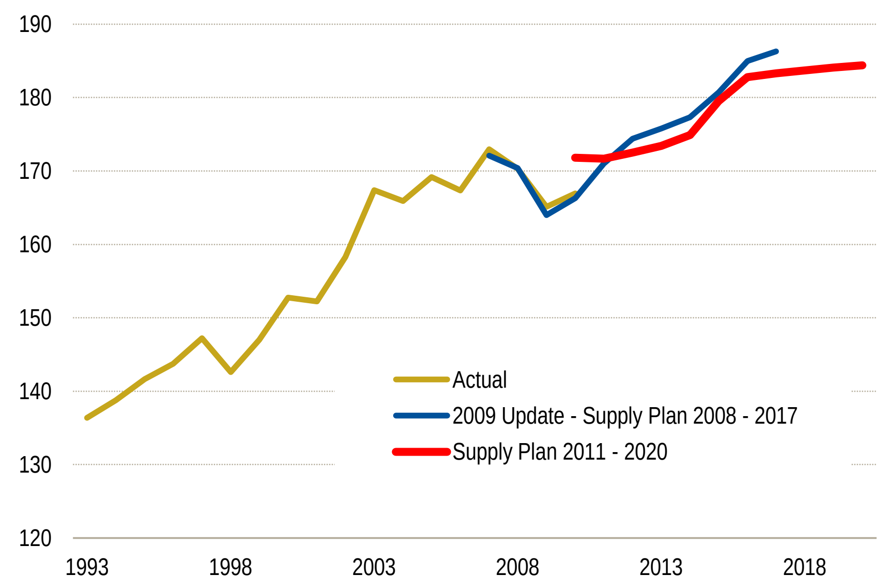
Source: Hydro-Quebec, Navigant

In addition to the investments in Eastmain-1-A/Sarcelle/Rupert and La Tuque, Hydro Quebec has broken ground on the Romaine Complex, which is a planned 1550 MW of new capacity, representing 8.0 TWh per year. Collectively these investments represent over 2,500 MW of capacity and 16.7 TWh of new energy supply. The energy from the Romaine project is planned to be used for export and is also part of Quebec's Northern Plan which calls for a total 4,500 MW of new generation investment (including the 1,550 from the Romaine Complex). Hydro Quebec is currently in a screening process for new projects.

2. **Hydro Quebec Distribution's 2011 – 2020 Supply Plan**: In November 2010, Hydro Quebec filed its 2011–2020 Supply Plan with the Regie de l'Energie. The 2011 – 2020 Supply Plan forecasted slower growth in electricity demand as compared to the previous supply plan as well as an energy surplus in the near term, causing Hydro Quebec Distribution (HQD), the retail load serving entity, to suspend existing supply contracts with independent power producers as well as cycling contracts it has in place with Hydro Quebec Production (HQP), the entity owning and operating the generation. The November 2011 update to the 2011 – 2020 Supply Plan has further

revised the energy forecast lower than in the November 2010. See Figure 3-1 below. The result of HQD forecasting lower growth is that HQP will have additional energy to export, over and above any new supply that it is developing or refurbishing.

Figure 3-1. Quebec's Forecasted Energy Demand (TWh)



Source: Hydro Quebec Supply Plans, Navigant

Key Observation: Hydro Quebec will have increased capacity and energy available for export as domestic demand remains lower than expected until 2020.

3.2 Renewable Energy

3.2.1 Demand for Renewable Energy

With the exception of Vermont, each of the New England states has a mandatory RPS requiring that a percentage of the retail consumption be procured from eligible renewable resources. These resource generally include wind, landfill gas, solar, photovoltaic (PV), small hydro, tidal power, biomass, and other technology types. Many of the states' RPS programs include separate requirements for new and existing renewable resources, with the requirement for new resources increasing over time. New resources may be used to fulfill either requirement. Load serving entities (LSEs), such as retail energy suppliers and electric utilities offering standard offer service, are required to meet state RPS requirements. In most states, municipal loads are not required to meet the requirement. Table 3-3 provides an estimate of the RPS requirements for new resources the New England states. A description of each States' requirements is also provided below.

Table 3-3. Overview of State RPS Standards

State	Incremental Amount	Year
Connecticut	20%	2020
Maine	10%	2017
Massachusetts	15%	2020
New Hampshire	16%	2019
Rhode Island	16%	2020
Vermont	20%	2017

Source: DSIRE, Navigant

Maine initially passed one of the highest percentage requirements of any state standard, requiring 30 percent of the generation sold in the state to come from eligible resources by 2000. This requirement, includes any renewable resources regardless of when it was developed (i.e., existing resources including hydro). Additionally, in June 2006, Maine adopted a renewable portfolio goal to increase new renewable energy capacity by 10 percent by 2017. This portion includes only new renewable energy sources entering commercial operation after September 1, 2005.

Massachusetts set incremental rising standards, beginning with a minimum requirement of 1 percent of renewable generation by 2003, with an annual increase of 0.5 percent through 2009, and a nominal 1 percent annual increase thereafter. Massachusetts LSEs are required to either procure a specified percentage of their retail sales from approved renewable sources or make an Alternative Compliance Payment (ACP). Ultimately, these monies provide incentives for renewable project development but there is not a requirement for actual renewable projects to be developed.

Rhode Island also set incrementally increasing requirements in its RPS program, requiring a minimum of 3 percent in 2007 and rising to 16 percent by 2019. Similar to Massachusetts, Rhode Island LSEs can also either procure renewable energy from a certified resource or make an ACP.

Connecticut set standards requiring that 7 percent of the energy procured by the LSEs come from Class I renewable resources and 10 percent from Class I or Class II renewable resources by 2010.

In April 2007, New Hampshire became the last state in the Northeast to enact a RPS by requiring 25 percent of the state's energy to come from renewable sources by 2025. Similar to the above programs, LSEs may either procure renewable energy from a certified resource or make an ACP.

Renewable resources can be imported from neighboring states or regions to meet the state requirements. For example, in 2007 Massachusetts LSEs purchased RECs from New York and Canada to meet their annual requirements. However, not all resources are qualified to provide RECs; each state has specific rules related to project size limits and other requirements.

Vermont does not have a typical RPS, but has a Sustainably Priced Energy Enterprise Development (SPEED) Program, created by to promote renewable energy development. Legislation enacted in March 2008 established a goal that 20% of total statewide electric retail sales be generated by new SPEED resources by 2017. Per state law, the SPEED Program must meet certain criteria by 2012. If the Vermont

Public Service Board (PSB) determines that the established minimum obligations of the SPEED program are not met, then a binding RPS would be developed. Currently large hydro resources of any size to count towards its SPEED Program renewable energy goals.[20] Provided below is summary of the programs and types of resources that qualify for participating in each of the state programs.

Table 3-4. Summary of RPS Rules and Requirements

State	Eligible Resources	Requirements
Connecticut	• Class I resources include: Solar, wind, fuel cells, landfills, sustainable biomass facilities, wave or tidal power, small hydro, and others. • Class II resources include: trash-to-energy, and existing biomass and small run-of-the-river hydro. • Class III includes combined heat and power (CHP) and energy efficiency.	• Class I renewable energy obligation begins in 2004 with 1%, increasing to 20 percent by 2020. • Class II is fixed at 3%. Class III begins at 1% in 2007 and increases to 4% by 2010, and is fixed thereafter.
Massachusetts	• Class I resources include: PV; solar; wind; ocean thermal, wave or tidal energy; fuel cells utilizing renewable fuels; landfill gas; and new hydro facilities. Class I is for facilities installed after December 31, 1997. • Class II includes PV; solar; wind energy; ocean thermal, wave or tidal energy; fuel cells utilizing renewable fuels; landfill gas; energy generated by certain existing small hydro facilities, and others. Class II resources include facilities operating before December 31, 1997.	• Class I begins in 2003 with 1%, increasing to 4% by 2009 and increasing thereafter annually by 1%. • Class II begins in 2009 and is fixed at 3.6%. Class II also includes a Waste Energy Minimum Standard that requires 3.5% of all sales to be met by waste energy.
New Hampshire	• Class I includes source which began operation after January 1, 2006 and includes wind; geothermal; biomass fuels; landfill gas; wave or tidal energy; solar, and other sources. • Class II includes new solar and solar technologies that began operation after January 1, 2006. • Class III includes existing biomass technologies (less than 25 MW) that began operation prior to January 1, 2006. • Class IV includes existing small hydro that began operation prior to January 1, 2006.	• Class I begins at 0.5% in 2009, increases to 1% in 2010, and increases by 1% annually thereafter to 16% by 2025. • Class II begins in 2010, increasing to 0.3% by 2014 and is fixed thereafter. • Class III begins at 3.5% in 2008, increasing to 6.5% in 2011 and is fixed thereafter. • Class IV begins in 2008 at 0.5%, increases to 1% in 2009, and is fixed thereafter.
Rhode Island	• The RPS includes: solar, PV, landfill gas, wind, biomass, hydro, geothermal, anaerobic digestion, tidal and wave energy, biodiesel, fuel cells using renewable fuels.	• The requirement begins at 3% by the end of 2007, and then increases an additional 0.5% per year through 2010, an additional 1% per year from 2011 through 2014, and an additional 1.5% per year from 2015 through 2019.
Maine	• Class I facilities include fuel cells, tidal power, solar, wind, geothermal, certain hydro, and biomass facilities that began operation after September 1, 2005. • Class II resources include all facilities included in Class I, including MSW and hydro that do not meet the requirements of Class I. Class II does not have any date restrictions. • Except for wind power installation, Class I and Class II renewable energy facilities must not have a nameplate capacity that exceeds 100 MW.	• The Class I requirement begins at 1% in 2008 and increases by 1% annually thereafter. • Class II is fixed at 30% annually.

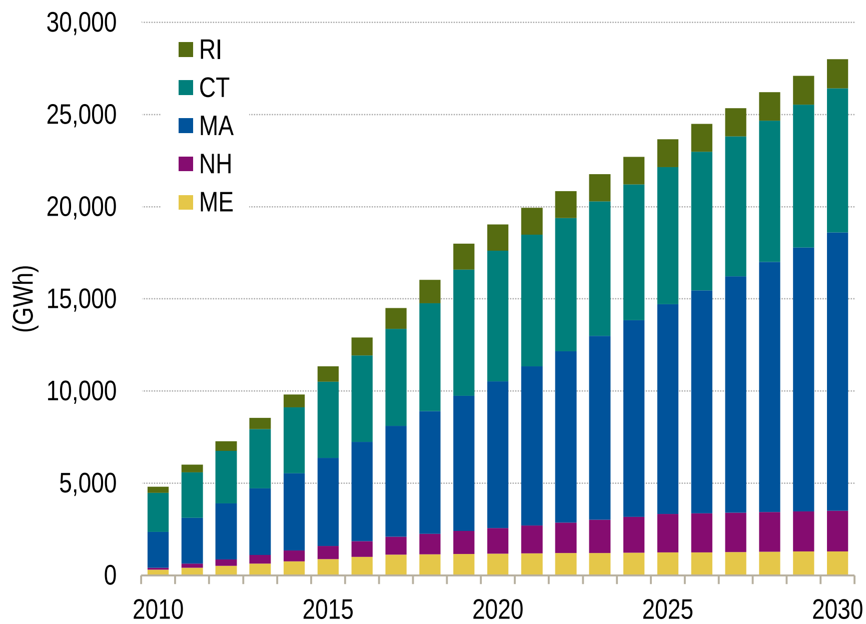
Source: Summarize from Dsireusa.org

[20] See Mary G. Powell, *Treatment of Large Hydropower as a Renewable Resource,* Energy Law Journal, Volume 32 at 553 for a discussion on the development of this program.

3.2.2 Supply of Renewable Energy

Based on ISO-NE assumptions on state energy growth, Navigant has prepared a projection of the state RPS requirements. As noted in Table 3-4, the RPS requirement increases as a percent of retail energy sales and as load grows. Figure 3-2 provides projection of the RPS requirements by New England state.

Figure 3-2. Projection of RPS Requirements by State



Source: ISO-NE, Navigant

The RPS programs for New England states required roughly 3,500 GWh of certified renewable energy resource be purchased in 2008. The RPS requirement is projected to increase from approximately 5,000 GWh in 2010 to over 19,000 GWh by 2020.

Based on state compliance reports, New England's LSE's have met their RPS requirements with a combination of new resources and imported purchases. This requirement was met through a mix of resources located in New England, New York, and Canada.

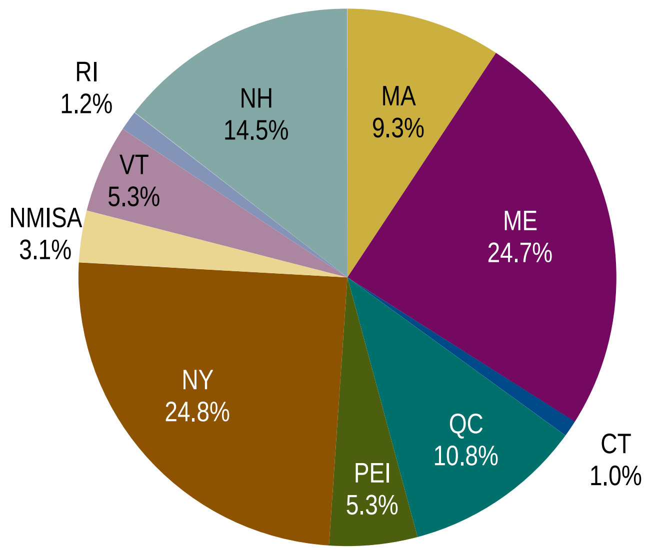
By way of example, Navigant researched where Massachusetts retail suppliers are purchasing renewable energy resources to meet their requirements. Based on our findings, we have identified that LSE's are purchasing RECs from entities located outside of the region to meet their requirements. Based on a compliance report prepared by the Massachusetts Division of Energy Resources (DOER), we have found the following:

- In 2009, Massachusetts retail electricity suppliers purchased 56% of the credits from suppliers inside New England, 28% from suppliers in Northern Maine and NY, and 16% from Canadian entities.
- Imports from Prince Edward Island (PEI) have increased significantly from 2007-2009. Other notable increases came from NH and VT.

- In addition to these purchases, NSTAR and National Grid, two of the largest REC purchasers in the region, banked credits for use in future years.
- NSTAR recently procured NEPOOL GIS RECs through a competitive bidding process that resulted in two long-term contracts.

Based on the DOER's analysis, Figure 3-3 identifies where Class I RECs as purchased by Massachusetts LSE's were sourced.

Figure 3-3. 2009 RPS Class I Compliance by Generator Location



Source: Compliance Report[21]

The renewable market will become increasingly more competitive as RPS requirements increase and the available sites for renewable resources are developed. The region will need to provide increased incentives and coordination as well as expansion of the transmission system if New England is to be self-sufficient in meeting its renewable resource requirements.

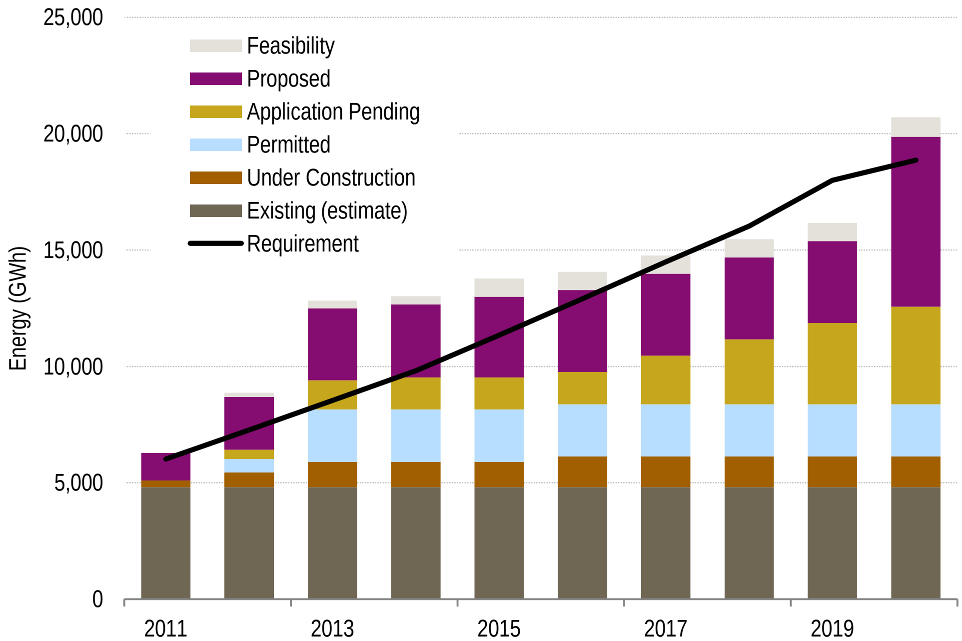
3.2.3 Current State of In-Region Supply

Wind resource development will likely make up the majority of renewable resources that are developed within New England, with minimal biomass and solar development. Wind resources will be predominantly located in Northern Maine, New Hampshire, Vermont, and off the coast of southeastern Massachusetts. These are the locations that have been identified in several studies related to renewable energy potential studies. However, to date renewable resources have been slow to develop, with energy providers opting for less expensive imports as opposed to developing new resources. As a result, regionally developed renewable resources are not expected to meet the projected RPS requirements, providing an opportunity for imports.

[21] Massachusetts Renewable and Alternative Energy Portfolio Standards (RPS & APS) Annual Compliance Plan for 2009, November 17, 2010 as revised January 11, 2011.

The chart below provides an estimate of the supply and demand balance for RECs New England. Assuming that the RPS requirements were completely met in 2010, there is a significant gap projected between future requirements and planned resources. The planned resources include Cape Wind, a controversial 500 MW wind farm planned for Nantucket Sound in Massachusetts. If this project does not materialize, the potential shortfall could be significantly larger than projected.

Figure 3-4. Projected Supply of Renewable Resources



Source: Energy Velocity, Navigant

3.2.4 Purchases of Renewable Energy in New England

New England's electric utilities, who are LSEs to those customers taking standard offer service, have issued solicitations to meet their state's RPS requirements. National Grid, the utility serving portions of Massachusetts, New Hampshire and Rhode Island, has held several renewable energy solicitations. For the most part they are issued in conjunction with RFPs for energy to shape their demand, and the renewable energy is required as a percentage of that – however, each solicitation specifies that the renewable energy can be in the form of NEPOOL GIS certified RECs, with REC prices to be offered separately. National Grid will accept energy bids separately from the RECs, so they are essentially running energy and REC RFPs in parallel, as they don't need to come from the same supplier. They have RFPs available for download back to 2008 on their web-site and most of them are essentially the same. Contract length tends to be anywhere from a few months to a few years. They also have a few RFPs for long-term contracts in Rhode Island based on their desire to have some renewable energy contracted long term even though they have already fulfilled their requirement for long-term contracts. One was also for renewable energy on Shoreham Island in Rhode Island. National Grid also had a couple of long-term RFPs for distributed energy offered in 15-year contracts. Unitil and NSTAR RFPs were also reviewed. Their RFPs appear to be for RECs only and relatively short term (1 year at a time).

3.2.5 Renewable Energy from Atlantic Canada

Currently, large hydro cannot participate in the RPS programs administered by the five New England states that have requirements (Maine is the one exception that will allow large hydro to qualify). Legislative changes would be necessary to change these rules. Recent legislative attempts to change these rules have stalled or have been tabled for discussion at a later time.

Table 3-5. State RPS Programs Regarding Large Hydro

State	Allows Imports from Canada to Meet RPS	Large Hydro Included in RPS	Class I RPS Requirement 2020 (GWh)	Market Potential for AC	Class I RPS Requirement 2030 (GWh)	Market Potential for AC
Connecticut	No – Must be located in ISO-NE or select states to qualify	No	7,100	0	7,800	0
Rhode Island	Yes – Must be located within or delivered into NEPOOL	No (30 MW limit)	1,400	1,400	1,600	1,600
Maine	Yes – Must be located within or delivered into NEPOOL	No (100 MW limit)	1,200	1,200	1,300	1,300
New Hampshire	Yes – Must be located within or delivered into NEPOOL	No	1,400	1,400	2,200	1,400
Massachusetts	Yes – Must be located within or delivered into NEPOOL	No	8,000	8,000	15,000	15,000
Total			19,100	12,000	28,000	20,200

Source: Navigant

3.2.6 Potential Changes to State RPS Programs

State's attempts in New England to change legislation to allow large hydro to count towards RPS requirements have not been successful.

Maine

- In 2012 the Maine Legislature introduced Legislative Document 1683, "An Act to Lower the Price of Electricity for Maine Consumers." The Act proposed to eliminate the 100 MW limit on the size of hydroelectric facilities included in the definition of renewable capacity resource. This Act died on April 13, 2012.

Connecticut

- The re-written SB493 removed the RPS Class I requirement rollbacks originally included in SB463, but retained the incentives for energy efficiency, CHP technology, and residential/commercial scale solar.[1,2]
- Another bill was proposed in early 2011 aimed at reducing the cost of renewable energy in Connecticut. Part of the bill would allow large-scale hydroelectric resource to count towards the RPS requirement. The bill was tabled in May, 2011 and has not had any progress since.[3,4]

New Hampshire

- Similarly to CT, the New Hampshire legislature proposed a new bill that would allow large-scale hydro to count towards its RPS requirements. However, the bill was halted in the house and deemed "inexpedient to legislate."[5,6]

3.3 Project Economics

This section of the report reviews the economics of selling the output of clean and renewable resources from Atlantic Canada into the New England market. For this assessment, we provide a comparison of the all-in costs of a wind project developed in Maine to the revenue that the project would receive from selling into the spot capacity and energy markets. For this analysis, the difference between the total costs and the total revenue is the value that the REC payment would need to be to support the project. We also calculate the "net back" value that would be realized by a project located in Atlantic Canada and selling into New England, net of transmission charges that would be required to deliver the output to the ISO-NE transmission system. Our assessment is based on a 20-year levelized cost analysis presented in 2013 dollars on a dollars per kWh basis. Note that these estimates reflect specific assumptions regarding the capital cost for wind generation, natural gas prices and ISO-NE market prices as provided to Navigant by the AEG participants for consistency with other AEG studies.

3.3.1 Levelized Cost Scenarios

To calculate the value of REC payments under a diverse but realistic set of assumptions, Navigant prepared an analysis of the costs and payments related to a wind plant developed in Maine. The wind turbine is considered the least-cost renewable resource option for New England. The analysis considered a 2013 commercial operation date, and relied on capital costs of $2,200/kW and energy pricing assumptions as provided by the AEG Project Steering Committee for consistency with other analysis being performed. We assume a 27% capacity factor and a $43/kW-year fixed O&M charge. Capacity payments are based on FCM results and Navigant forecasts, and a 6.0% nominal discount rate was used for the analysis.

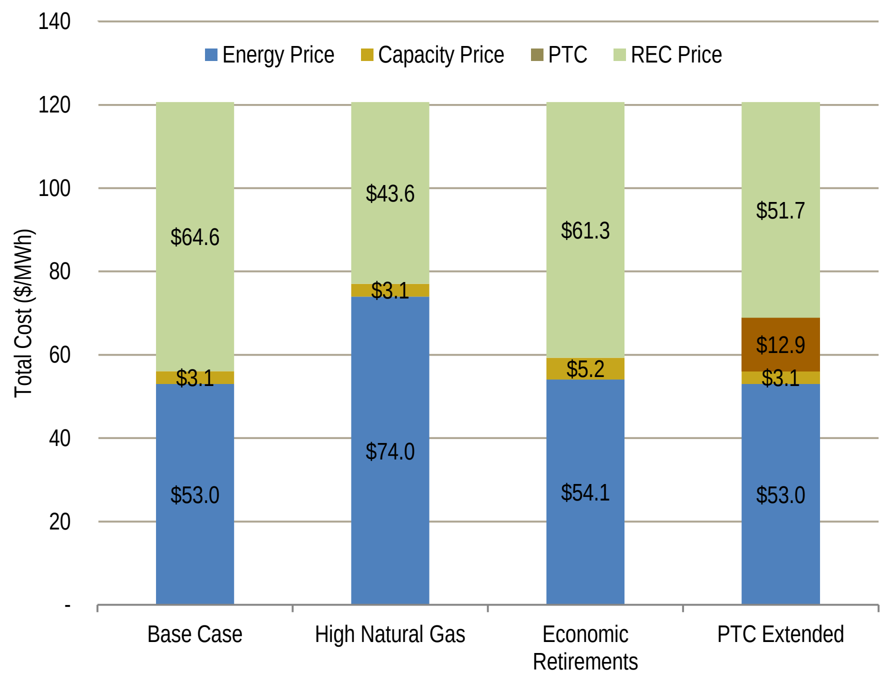
We prepared this analysis under four scenarios, reflecting several industry uncertainties as identified in this report. The analysis is presented in the form of a levelized price analysis, presented in $/MWh. The cases are as follows:

1. A base case, reflecting expected natural gas prices, no retirements, and no extension of the PTC;
2. A high natural gas price case, reflecting gas prices at 150% of base case gas prices and with all other parameters as above;
3. A retirement case, reflecting 3,500 MW of oil and coal assets being retired from the ISO-NE capacity market in 2016 and 2017. There is also a small impact to energy prices as a result of these retirements; and
4. A PTC extension case, reflecting all base case assumptions and the extension of the PTC for the first 10-years of the project.

Results of the levelized analysis are presented in the chart below. As mentioned above, the required REC price is calculated as the net revenue shortfall for the wind project, and does not reflect current REC prices. The results of the analysis indicate that the REC price would need to be $64.60/MWh under base case conditions to support the all-in costs of the project. The results for the high natural gas case indicate the REC payment would need to be $43.60/MWh to support the all-in costs of the wind project. Under this case, natural gas prices would need to return to the $7-8/MMBtu range. The results of the retirement case, where approximately 3,500 MW of oil and coal capacity is retired from the New England market, indicates the levelized REC payment would need to be $61.30/MWh to support the project. Finally, under the PTC case, which includes an extension to the PTC that impacts project revenue, require REC payment of $51.70/MWh to support the all-in costs of the project.

The Alternative Compliance Payment (ACP) in Massachusetts for 2012 is $64.02/MWh. This rate has increased at an average rate about 2.3% per year for the last 5-years. However, current REC market is significantly less than the ACP, due to a regional supply that will outpace demand for the next few years. Additionally, if a large-scale project is developed, such as the Cape Wind, the market could remain soft for several more years. Although the current REC market will not support wind development under any of the cases, results of this analysis conclude that when the market reaches equilibrium, the cases with high fuel costs or an extension of the PTC are most favourable for project development. Figure 3-5 provides a comparison of the revenues associated with the capacity and energy markets and the resulting REC pricing to support the all-in costs of the project.

Figure 3-5. Comparison of the Costs of a Wind Resource in New England



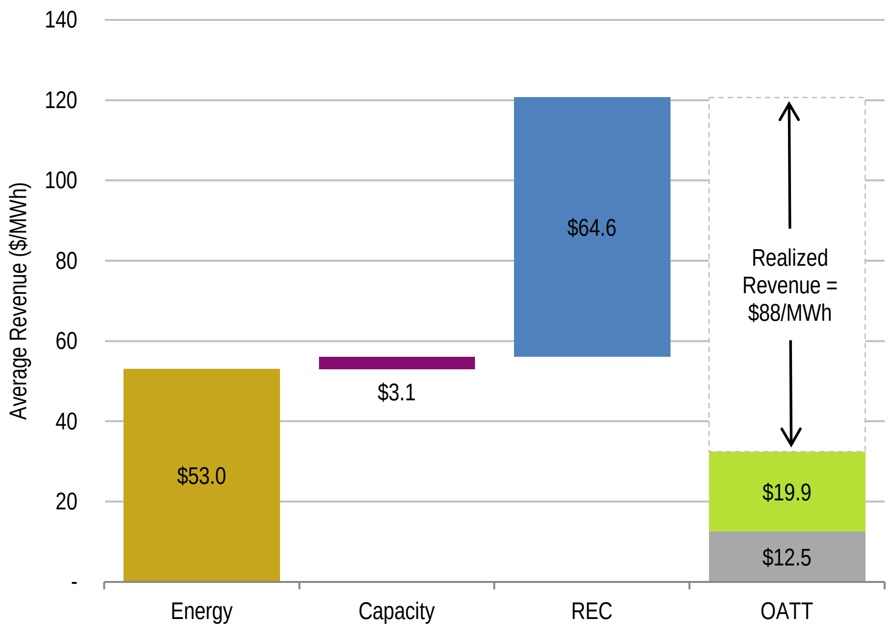
Source: Navigant

3.3.2 Netback Analysis

As mentioned above, as part of the scenario analysis Navigant also analyzed the "net back" price that would be realized by a project located in Atlantic Canada and selling into New England. The netback amount would be net of any transmission charges or losses required for delivering the energy into New England. Figure 3-6 provides a calculation of the netback price for a wind resource located in Nova Scotia and selling into New England. This analysis relates to the base case analysis described above. As can be seen, the netback price to wind located in Nova Scotia will be less transmission costs (identified as

OATT in Figure 3-6)[22]. A similar assessment can be developed for projects located in other provinces and for each of the scenarios presented in Figure 3-5.

Figure 3-6. Realized "Netback" Price of a Wind Resource from Nova Scotia

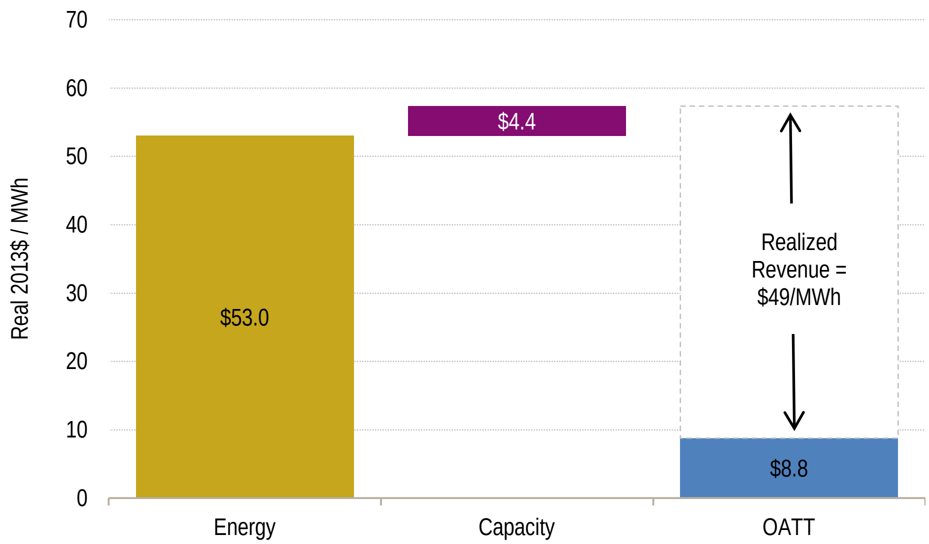


Source: Navigant

Similar to above, the netback price was also calculated for baseload clean energy sited in Nova Scotia. Under this case, the netback price firm clean energy would be the prevailing energy and capacity rate, less any transmission charges. A similar analysis can be constructed for each of the provinces and under each of the scenarios.

[22] For this illustrative analysis we have included non-firm transmission service. It should be noted that firm transmission service, while not a requirement for participating in the New England REC market, may be a prudent business decision depending on the non-delivery charges or other penalties associated with not fulfilling specific contractual obligations for the sale of RECs. For example, in a recent REC solicitation held by NSTAR, the standard form purchase agreement included a delivery shortfall charge which is based on the difference between the Alternative Compliance Rate and the contract price.

Figure 3-7. Realized "Netback" Price for Firm Clean Baseload from Nova Scotia



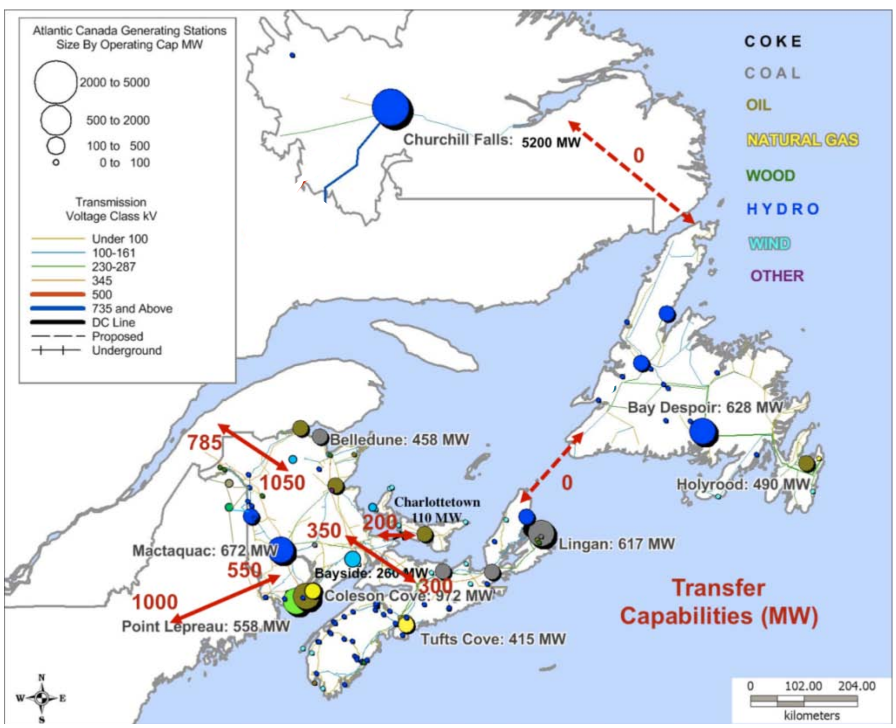
Source: Navigant

4. Opportunities for Greater Interprovincial Electricity Trade

The electricity system in the Atlantic region is comprised of three main components: (1) the Maritimes system, which is part of the Eastern Interconnection in North America and serves Nova Scotia (NS), New Brunswick (NB), Prince Edward Island (PEI) and portions of Northern Maine; (2) The Labrador system, which includes export transmission lines from Churchill Falls to the Labrador/Quebec border and serves the majority of customers in Labrador, with the exception of some remote areas; and (3) the Newfoundland system, which is currently isolated from other interconnections and serves all major communities in Newfoundland.

This region comprises five different utilities (Newfoundland and Labrador Hydro, Newfoundland Power, Nova Scotia Power Inc., NB Power, and Maritime Electric), and a number of different municipal electricity providers. Nova Scotia currently has six municipal electric utilities, New Brunswick maintains three, while PEI has one. While a few of these municipal utilities own and operate their own generating stations, the majority purchase bulk power from their larger counterparts to service their communities' needs. In addition to the primary electricity system, there are a number of remote or isolated areas relying primarily on small-scale diesel generators or wind power to supply isolated communities.

Figure 4-1. Atlantic Area Generation and Interconnections



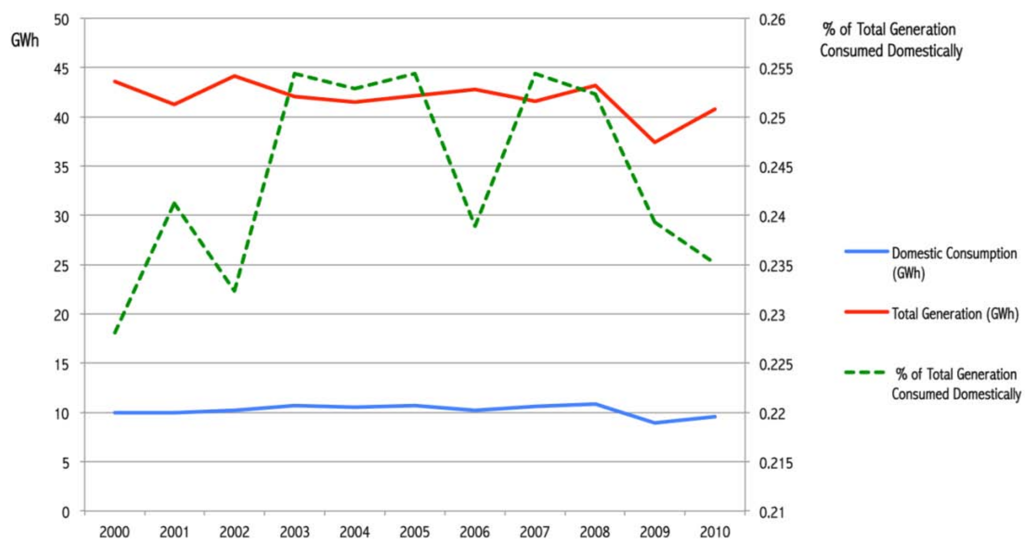
Source: WKM Energy Consultants Inc.

4.1 Newfoundland and Labrador

4.1.1 Current Supply and Demand Dynamics

Newfoundland and Labrador generates electricity from a variety of different sources, including hydropower, wind, heavy fuel oil, and diesel. The majority of electricity generated within the Province comes from hydroelectricity, and is exported to Quebec through a long-term supply contract. As a result, Newfoundland and Labrador is a net exporter of electricity, producing roughly four times more power than it consumed in 2010.[23] Figure 4-2 depicts the Province's electricity consumption relative to its overall generation.

Figure 4-2. Newfoundland and Labrador Electricity Generation and Consumption



Source: National Energy Board

Approximately 97% of total provincial electricity generation in 2010 was hydroelectric. Most of this is generated by the Churchill Falls generating station in central Labrador, which has a total capacity of 5,428MW, making it the second largest hydroelectric facility in Canada and the ninth largest in the world. In addition to Churchill Falls, the Province has a number of smaller hydroelectric facilities, adding a further 1,200 MW of capacity, a large oil-fired generating station at Holyrood (490 MW), four gas turbines generating stations and 25 diesel-fired thermal plants servicing mostly remote areas. In 2006, the Province also completed feasibility studies to develop several new small-scale hydro projects, which would collectively add approximately 59 MW of new capacity. Additionally, various long-term supply options have been considered including wind, small hydro, thermal, and Lower Churchill.

There are two utilities supplying power to the Province: Newfoundland Power, a private utility owned and operated by Fortis Inc., and Newfoundland and Labrador Hydro, a government owned energy service provider that owns many energy assets in the Province, including the existing Churchill Falls hydroelectric facility. Despite being the smaller of the two utilities with roughly 140MW of generating

[23] Source: National Energy Board (2011), http://www.neb-one.gc.ca/clf-nsi/rnrgynfmtn/nrgyrprt/nrgyftr/nrgyftr-eng.html#s7

capacity, Newfoundland Power services 86% of the Province's customers, with a customer base of 243,000 in 2010.[24] With annual sales in 2010 of 5.4 TWh, the utility has over 11,000km of transmission and distribution lines serving communities throughout the island portion of the province.

Newfoundland and Labrador Hydro has a smaller customer base than Newfoundland Power, but boasts a much larger asset base. Due to the Province's sparse population, Newfoundland and Labrador Hydro also provides electricity to several remote communities; many of these are located along the eastern coast of Labrador and southern Newfoundland.

Newfoundland and Labrador also has abundant wind power resources. A wind resource map completed for the Province shows that it has large expanses with average wind speeds at 50 meters of 8-10m/s, making it one of Canada's premier sites for wind power development. Operating wind farms in Newfoundland and Labrador include installations on the island of Ramea, as well as in St. Lawrence and Fermeuse. Collectively, these generation resources add 54 MW to the Province's total electrical capacity, and constitute less than 1% of the Province's overall generation mix. In total, approximately 97% of total provincial electricity generation in 2010 was hydroelectric, including Churchill Falls.

In a recent supply-side development, Nalcor Energy has recently proposed a plan for the long-term electricity supply for the Island of Newfoundland comprising development of the 824 MW Muskrat Falls hydroelectric facility in conjunction with the 900 MW, 1,100 km HVdc Labrador-Island Link (LIL) from Labrador to just outside St. John's[25]. This proposal was the subject of a recent Public Utilities Board proceeding and the Board's final ruling is expected by March 31, 2012.

Nalcor Energy and Emera, owner of Nova Scotia Power Inc., also reached agreement for the long-term supply of a 1 TWh block of power from Muskrat Falls (representing a portion of the projected supply in excess of the Island of Newfoundland's requirements) through the 500 MW HVdc Maritime Link from Newfoundland to Nova Scotia. The agreement also includes provision for Emera to upgrade intertie capacity with New Brunswick to facilitate potential export power sales from Newfoundland and Labrador into New Brunswick and New England.

In addition to Muskrat Falls, potential significant generation development opportunities in Labrador include the 2250 MW Gull Island hydroelectric facility. The federal government announced its support for the Muskrat Falls and associated HVdc links in August 2011 by agreeing to provide a loan guarantee.[26] It is estimated that the Muskrat Falls project will deliver 4.9 TWh of electricity per year.

Figure 4-3 provides an overview of the potential pathways for the export opportunities from the Lower Churchill project. Currently, the route being investigated would run into Newfoundland via an undersea cable, and then link to Nova Scotia at Lingan via a 180km HVDC undersea line.[27]

[24]http://www.newfoundlandpower.com/Content/ContentManagement/3464/File/2010%20Annual%20Report%20Final%20Mar%2021%202011.pdf

[25] Independent Supply Decision Review, Navigant Consulting Ltd,, September 14, 2011

[26] Source: NRCAN Press release: http://www.nrcan.gc.ca/media-room/news-release/2011/77/1395

[27] See Atlantica Center for Energy (2011). http://www.atlanticaenergy.org/uploads/file/Atlantica%20Centre%20for%20Energy%20Paper%20-%20Lower%20Churchill%20Final%20June%2030th%202011.pdf

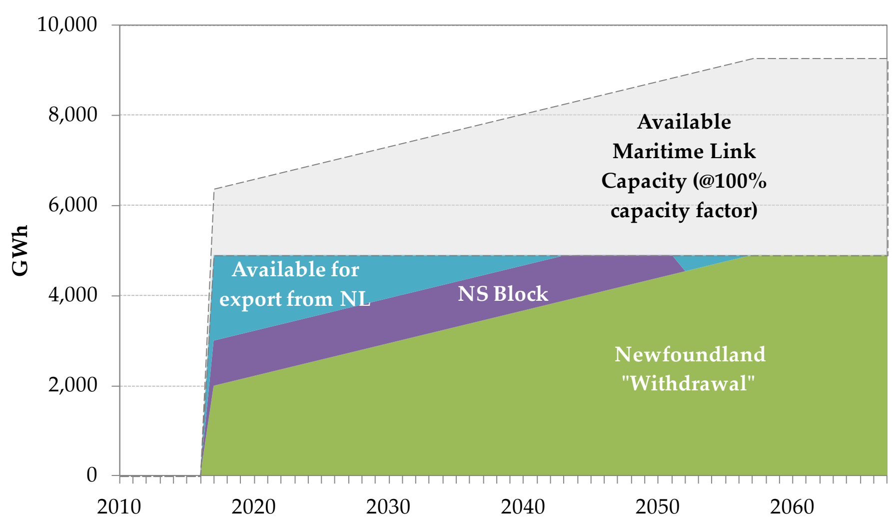
Figure 4-3. Map of the Lower Churchill Falls Projected Pathway

Source: Nova Scotia Power

The Island of Newfoundland's electricity requirements from Muskrat Falls are expected to increase with island demand until all of the Muskrat Falls output would serve the Island of Newfoundland by approximately 2055.

The following chart illustrates the approximate projected requirements of Newfoundland relative to the projected 4.9 TWh annual output from Muskrat Falls along with the 1 TWh "NS Block". The blue "slice" represents the projected Muskrat Falls output in excess of 1) the Newfoundland requirements and 2) the NS Block and would be available for export from NL.

Figure 4-4. Approximate Breakdown of Muskrat Falls Output and Available Maritime Link Capacity



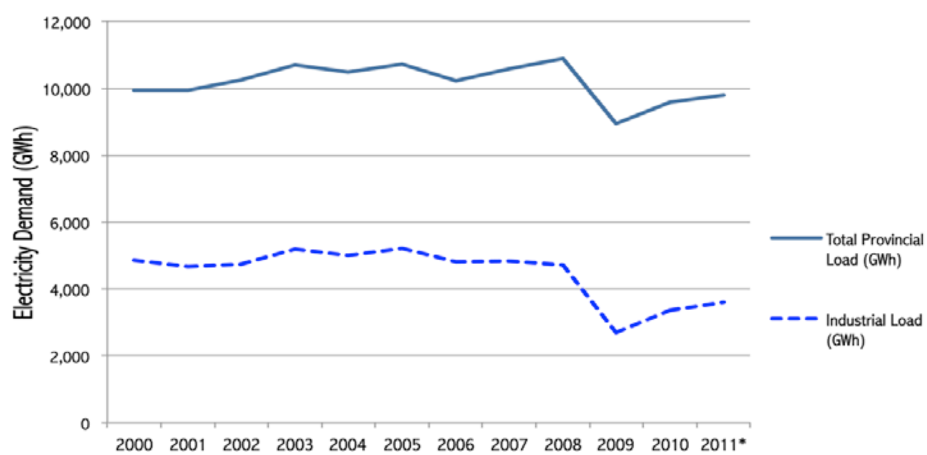
Source: Independent Supply Decision Review, Navigant Consulting Ltd, September 14, 2011

On July 31, 2012, Nalcor and Emera executed thirteen agreements covering the commercial and physical arrangements between these companies related to the Muskrat Falls hydroelectric and associated HVdc transmission (Labrador-Island Link and Maritime Link) projects.[28] Transmission access for Nalcor through Nova Scotia and New Brunswick into the New England markets is among the many arrangements covered in these agreements. The transmission capacity available to Nalcor through these agreements would allow any surplus energy from Muskrat Falls (the blue wedge of energy labeled as "*Available for export from NL*" in Figure 4-4) to be sold into New England if desired. Other possible markets for this energy include Nova Scotia, New Brunswick and, using the transmission access Nalcor currently has through Quebec, Ontario or New York.

The chart also shows the additional Maritime Link power transfer capacity of up to 4,400 GWh by 2055 (assuming 100% capacity factor) that would be available for additional exports from NL into Nova Scotia and beyond.

Turning to electricity demand, it can be seen that load in Newfoundland and Labrador is slightly below its level in 2000 (1-2% decline), despite a growing population in the St. John's area. This decrease in load is largely due to a decrease in industrial electricity demand in the Province. Figure 4-5 maps this decline in demand over the last decade. However, Newfoundland and Labrador's most recent energy forecast projects a near-term period of overall load growth for the Island interconnected system. The compound annual growth rate between for the Island System is projected at 2.7% between 2009 and 2014, 1.7% between 2009 and 2019, and 1.3% between 2009 and 2029[29].

Figure 4-5. Load Trends in Newfoundland and Labrador, 2000-2011



Source: National Energy Board

[28] The agreements are available at: http://www.nalcorenergy.com/formal-agreements.asp
[29] Source: Summary of Newfoundland and Labrador Hydro 2010 Long Term Planning Load Forecast, Muskrat Falls Project - Exhibit 27.

4.1.2 Policy and Regulatory

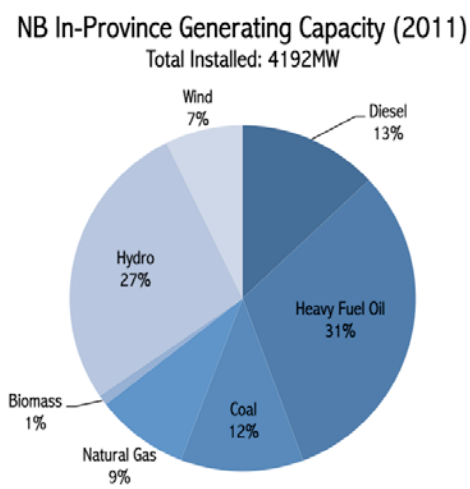
As for policy and regulatory developments, the Province remains committed to phasing out its Holyrood Generating Station if the Muskrat Falls project is completed. The Holyrood Generating Station is a significant source of price volatility and a major contributor to the Province's greenhouse gas (GHG) emissions. While the Province does not have a formal Renewable Portfolio Standard – largely due to the fact that approximately 97% of total provincial electricity generation in 2010 was hydroelectric and approximately 90% of capacity is clean/renewable – it is likely to continue to increase its domestic renewable energy capacity in the years ahead, both from the above noted Lower Churchill projects and continued wind power development.

4.2 New Brunswick

4.2.1 Current Supply and Demand Dynamics

New Brunswick has a highly diversified electricity generation mix, including hydro, coal, nuclear, wind, heavy fuel oil, diesel, biomass and natural gas. It has the most diversified supply mix of any Province in the region.

Figure 4-6. Total Electrical Capacity in New Brunswick



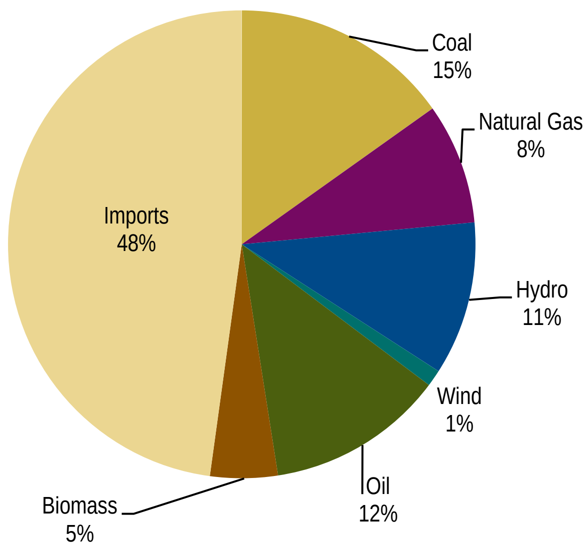
Source: New Brunswick System Operator 2011

While this represents the current installed capacity, it does not entirely reflect current generation trends. First, the Province's sole nuclear power plant, Point Lepreau, is currently under refurbishment; it is expected that when it comes back online in fall 2012, it will have a slightly higher installed capacity at 660MW, and will contribute approximately 30% of the Province's total generation. Combined with the recent closure of Grand Lake (a small, 57MW coal-fired generating station) and the pending closure of Dalhousie Generating Station (a 299MW facility burning primarily heavy fuel oil), the Province is poised to become less reliant on fossil fuel sources and more reliant on a combination of imports and low carbon power.

New Brunswick is currently benefiting from a number of favourable market circumstances. While the Province has historically been a net exporter to Maine and New England, it has recently become a significant net importer while Point Lepreau has been off-line, purchasing low-cost gas-fired generation. In addition to imports, it continues to benefit from competitively priced hydroelectricity from Quebec. These two sources of imports are currently less expensive than much of the Province's own generation fleet; as a result, they have helped NB Power uphold a government mandate to freeze rates for three years starting in 2010.

The current reliance on imports is most notable during the winter months. For instance, in January and February 2011, imports represented approximately half of total electricity consumed in the Province.

Figure 4-7. New Brunswick Electricity Generation Mix (Jan 2011)



Source: New Brunswick System Operator

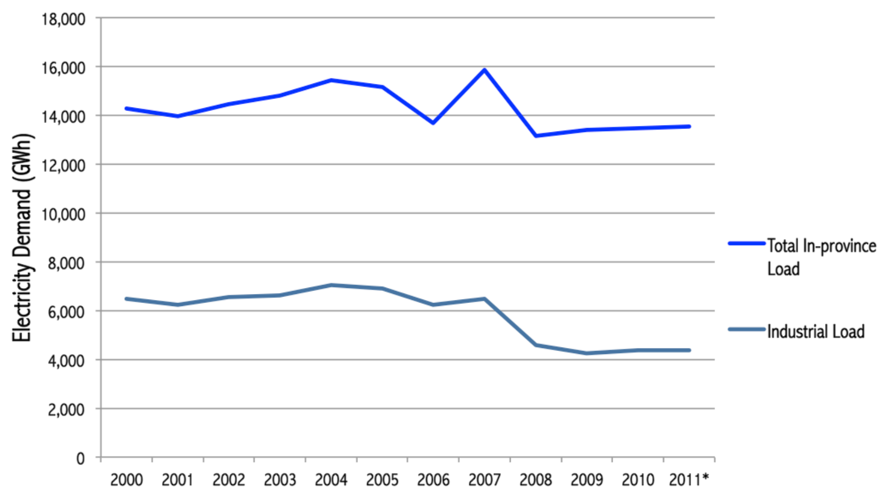
Other supply-side options that have been discussed to boost the supply of competitively priced electricity within the Province include the possibility of converting one or more units at the Coleson Cove generation station from heavy fuel oil to natural gas.[30] However, no concrete timeline has yet been set out for such a conversion.

Wind power represents roughly 300 MW of electrical capacity in the Province. When wind power flowing into New Brunswick from Northern Maine and PEI are included, the Province is responsible for balancing 550 MW of wind. Citing reliability and cost concerns, the government's recent *Energy Blueprint* has signaled a shift in strategy, and has chosen to put the brakes on further large-scale wind power development in New Brunswick, instead focusing on smaller, more widely distributed and locally owned renewable generation projects to meet its renewable energy targets. Aside from the return-to-operation of 660 MW of capacity from Point Lepreau, the Province's system operator does not foresee a requirement for any additional generation resources or electrical capacity over the next decade. In light of decreasing load, and the availability of low-cost imports, the Province has access to more than enough electricity to meet its own energy and reliability needs for the foreseeable future.

[30] http://www.cbc.ca/news/canada/new-brunswick/story/2011/05/18/nb-coleson-cove-natural-gas.html

Looking at the trend in electricity demand over the last decade, total load in New Brunswick has declined, with an acceleration of the trend since 2007. Since 2004, industrial electricity demand in the Province has decreased by 38%, representing a drop of almost 20% of total in-Province electricity use.[31] Considered as a whole, New Brunswick's in-Province load has decreased by approximately 2TWh since that time, or almost 13%. The downward trend in industrial demand is responsible for the largest share of this decline, but Efficiency NB's successful residential, commercial and industrial conservation initiatives have also contributed to this decline.

Figure 4-8. New Brunswick Electricity Demand, 2010-11



Source: National Energy Board

Despite this downward trend, current forecasts expect New Brunswick's electricity demand to return to an annual growth rate of 0.6%/year over the next decade. This includes an anticipated demand reduction of 390GWh/year from demand side management measures and naturally occurring efficiency improvements.

From a financial perspective, NB Power's high levels of debt, and ratio of debt to assets, remain among the highest in Canada. Debt service and depreciation make up between 30-35% of NB Power's annual expenses. This will remain a challenge in the years ahead, and will serve to further constrain NB Power's operational flexibility, as well as its ability to invest in new transmission or generation infrastructure on a stand-alone basis. However, the debt should not limit NB Power's ability or willingness to cooperate or partner on regional energy developments and projects. Further, the government has announced plans to initiate a debt reduction plan at NB Power with a goal of achieving a debt to equity ratio of 80/20 within ten years.

4.2.2 Policy and Regulatory

New Brunswick has recently revamped its RPS, aiming for a higher target, but with looser restrictions on eligible technologies. The previous RPS policy, adopted in 2006, established a target of 10% of total in-Province sales from new renewable sources by 2016. Changing market circumstances combined with a

[31] Source: NEB 2011, NBSO 2011

change in government have prompted a change in this strategy. The *New Brunswick Energy Blueprint*, launched in October 2011, establishes a new target of 40% renewable energy by 2020. Along with this new target, the eligibility requirements have been modified to include out-of-Province generation, and in particular, existing large hydroelectric and industrial biomass generation. The revised policy also places a greater focus on biomass resources, both for heating and for electricity generation.

The *Energy Blueprint* also sets out policies that require NB Power to purchase electricity generation from community-based renewable energy projects, including those developed by First Nations. If this proceeds to plan, it is expected to add another 75 megawatts of renewable capacity. A second development that aims to increase supply is the Large Industrial Renewable Energy Purchase Program (LIREPP) set out in the *Energy Blueprint*, which recognizes existing industrial biomass generation from the Province's pulp and paper mills for the purpose of the provincial RPS, and in future could result in new, in-Province generating capacity as eligible customers in other industrial sectors install renewable generation capacity to participate in the program.

4.3 Prince Edward Island

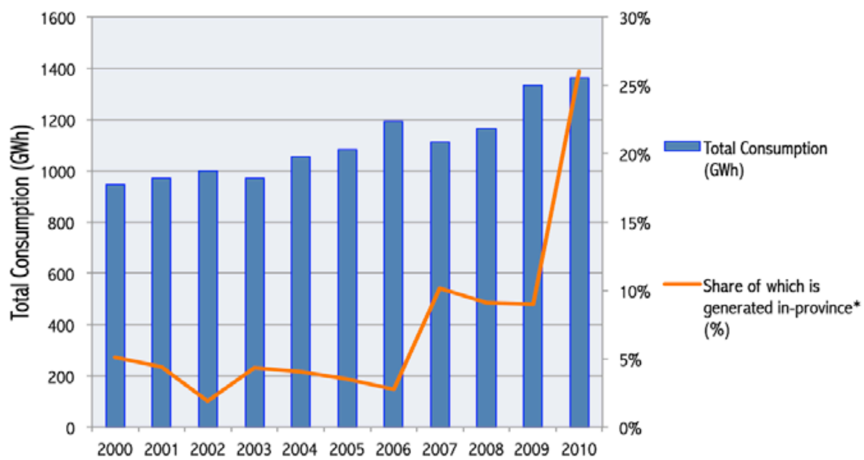
4.3.1 Supply and Demand Dynamics

PEI gets most of its electricity supply via two submarine cables that cross the Northumberland Strait and link up with the New Brunswick system. Each cable has a nominal capacity of 100 MW. There is currently 124 MW of export capacity from PEI to New Brunswick, and 200 MW of import capacity. The remainder of PEI's electricity comes from a combination of domestic wind power, biomass, and fossil fuel generation, including heavy fuel oil and diesel. The latter supply options are used primarily to service peak loads, and to provide reliability support.

From a technical standpoint, PEI is considered a load on the NBSO system. The latter has to manage load following and reliability for both provinces. The provincial utility, Maritime Electric, has recently renewed its purchase contract with NB Power, and both utilities are currently partnering to expand the transmission capacity linking the two provinces to enable greater interprovincial power flows.

Maritime Electric operates two generating stations in Charlottetown, one that burns heavy fuel oil with a capacity of 60 MW and the other a diesel-fired combustion turbine with a capacity of 49 MW. Maritime Electric also operates two diesel-fired combustion turbines with a combined capacity of 40 MW in the Town of Borden. The City of Summerside has a diesel-fired generating station as well, totaling a further 10 MW of available capacity. Due to the high cost of diesel generation, however, the Province relies far more on imports from New Brunswick than on domestic generation. While wind power has begun to increase the share of power generated for the island in recent years to over 20%, with a total installed capacity of over 160 MW, imports continue to supply the bulk of the island's electricity needs. Figure 4-9 highlights this trend.

Figure 4-9. PEI Electricity Demand, 2000-2010[32]



Source: NEB 2011; StatsCAN 2011

As the chart above shows, unlike other Atlantic Provinces, PEI's electricity demand has continued to grow steadily, and was only minimally impacted by the recent financial crisis. Since 2000, electricity demand has increased by 30%, making it the Atlantic Province with the highest and most sustained load growth over the past ten years.

4.3.2 Policy and Regulatory

In 2004, PEI became the first Province in the Atlantic region to adopt an RPS target, which aimed to meet 15% of its electricity needs with renewable energy by 2010.[33] It met its target three years ahead of schedule. Since then, PEI has adopted a comprehensive energy strategy that includes a goal of having 500 MW of wind power on line by 2013. While most of this will be for export, 100 MW is to be reserved for domestic use. By 2013, PEI aims to double the share of renewable energy in its electricity mix from 15% to 30%, and it has expressed a commitment to increase the share of renewable energy on the island from local and community-owned projects. This includes a stated objective to increase the use of biomass and biogas for electricity generation.

However, PEI has recently faced challenges delivering on this ambitious vision, partly due to transmission constraints and the difficulties of finding a suitable export market.

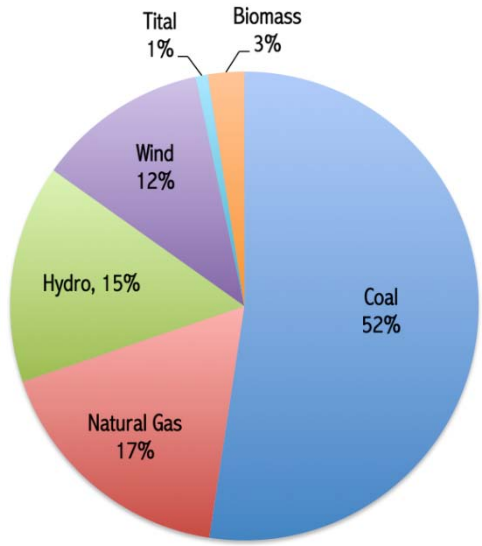
4.4 Nova Scotia

4.4.1 Supply and Demand Dynamics

Nova Scotia generates electricity from coal, fuel oil, natural gas, wind, hydropower, and tidal. The single largest source of generation in the Province, however, comes from coal, which represents over half of total installed capacity and approximately two thirds of total in-Province generation.

[32] Note that much of the growth in-province generation is wind power, and a significant share of this is being exported so the proportion of total consumption that is generated in province is less than implied.
[33] http://www.gov.pe.ca/news/getrelease.php3?number=3622

Figure 4-10. Nova Scotia Generating Capacity (2011)



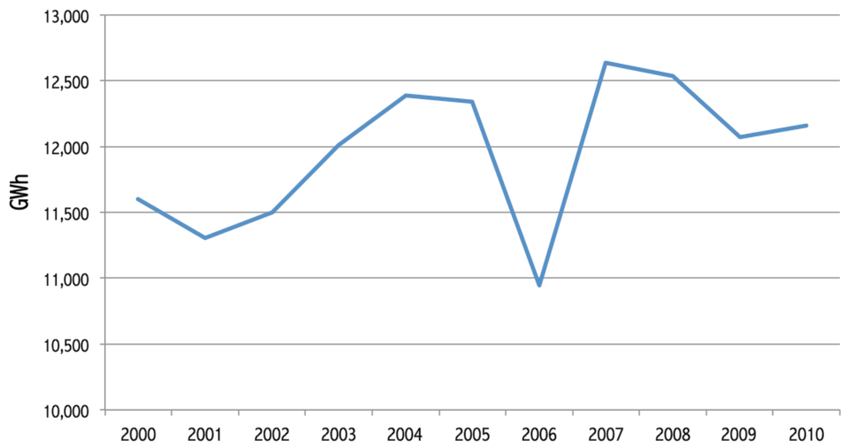
Source: NSPI 2011; StatsCAN 2011

In total, Nova Scotia Power Inc. (NSPI) has approximately 2,400 MW of installed electrical capacity. In addition to in-Province resources, it has three grid ties with New Brunswick that enable it to import up to 300 MW, and export up to 350 MW. In terms of renewable electricity (RE) capacity, Nova Scotia has 360 MW of hydroelectric capacity spread over several small and medium-sized facilities, and an additional 20 MW from the tidal power plant in Annapolis Royal. In recent years, it has added to that capacity a significant amount of wind power, totaling over 280 MW as of early 2011. Also, 2012 is expected to see several small wind projects added to the mix, including a 31.5 MW project in the Amherst area.[34]

In addition, and as discussed in the above section on Newfoundland and Labrador, Emera has recently signed an agreement with Nalcor to develop the 500 MW HVdc Maritime Link from Newfoundland to Nova Scotia and bring a minimum of 1 TWh of power from the Muskrat Falls hydroelectric facility into Nova Scotia. This will help meet Nova Scotia's ambitious energy and environmental objectives, and help gradually reduce its reliance on coal-fired generation. The proposed project will enable the province to replace a portion of its largest coal plant in Lingan at 620 MW. Electricity demand in the Province has experienced significant changes over the last five years, with a major decline in 2006, which rebounded back to previous levels by 2007.

[34] http://www.nspower.ca/en/home/environment/renewableenergy/wind/map.aspx

Figure 4-11. Nova Scotia Load (2000-2010)



Source: National Energy Board

This drop in demand, a decline of approximately 1.5TWh, was due to the temporary closure of a large pulp and paper mill in the Province in December 2005; the mill came back online at the end of 2006, returning provincial load back to its previous highs.[35] However, the onset of the financial crisis triggered a new downward trend in provincial demand. Since 2000, total electricity demand has increased by 4.5%, or just under 0.5%/year on average.

4.4.2 Policy and Regulatory

Nova Scotia's RPS sets out an ambitious target of supplying 25% of in-Province demand from renewable sources by 2015, and 40% by 2020. A significant driver of the RPS policy is to reduce the Province's reliance on coal-fired generation and meet federal air pollution regulations. In addition to these mercury-based regulations, Nova Scotia also has instated a hard cap on GHG emissions, aiming to reduce emissions by 10% below 1990 levels by 2020. This hard cap is only on the electricity sector, requiring a 2.5 MT reduction by 2020 or half of the Province's total GHG reduction goal of 5 MT.

In order to meet its RPS, Nova Scotia aims to use two tools: competitive solicitations, and a community-based feed-in tariff policy. The recently launched COMFIT policy, which came into effect in September 2011, is targeted at distribution-interconnected RE projects with a minimum annual load on the point of interconnection that is large enough to accept the rated generation output. This practically limits the average projects to less than 6 MW in size and in some cases less than 1 MW. In total, the Province aims to encourage some 300 GWh of new renewable electricity generation (up to 100 MW of new capacity) from locally owned renewable energy projects by 2020. Like many other feed-in-tariffs policies around the world, the tariffs are differentiated by technology type, including wind, tidal, biomass and small hydro, as well as by project size in the case of wind power.[36] If successful, this policy could lead to a significant surge in small, locally owned renewable energy projects in the Province, and help meet both environmental and energy security objectives..

[35] http://oasis.nspower.ca/site-nsp/media/Oasis/20110630%20NSPI%20to%20UARB%2010%20Year%20System%20Outlook%20Report%281%29.pdf
[36] See http://nsrenewables.ca/feed-tariffs

4.5 Regional Considerations

In addition to the specific considerations occurring in each of the four Atlantic Provinces discussed in the previous sections, there are a number of regional developments currently taking place that could have significant impacts on individual provinces' strategies in the years ahead. On one hand, these developments could serve as a catalyst for greater cooperation and could provide a template from which to discuss the opportunities for greater interprovincial power flows; alternatively, some provincial developments could be seen to be at odds with the AEG initiative and could even impede the expansion of interprovincial electricity trade. This section will briefly outline some of these developments.

The AEG strategy was launched by the federal government in collaboration with the Atlantic Provinces in 2009 in recognition of the region's significant potential for greater cooperation on energy issues. In the past, provinces have shown limited interest in expanding regional collaboration on energy trade, as each Province sought to further its own interests. However, both the Atlantica initiative[37] and the AEG initiative suggest the case for expanding such collaboration is enduring, and not simply a passing interest.

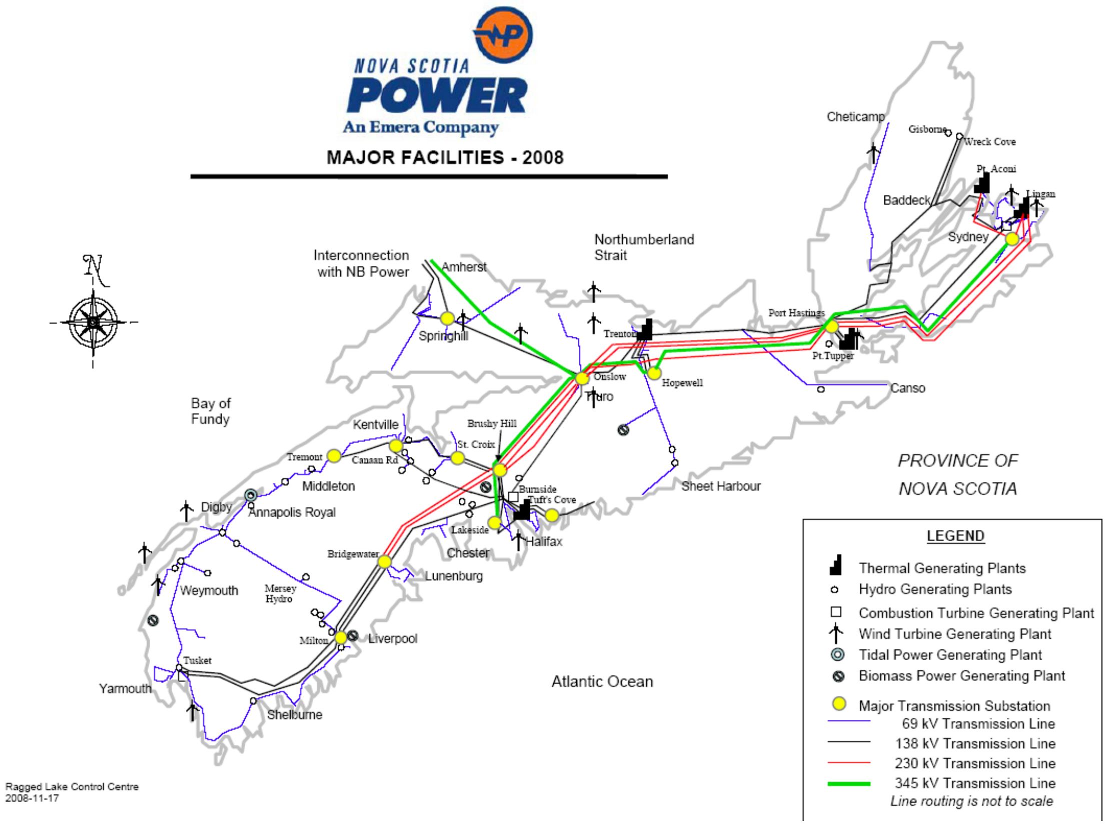
As the sections above have demonstrated, aside from the recent discussions between Nova Scotia and Newfoundland and Labrador to partner on the Lower Churchill project, and an upgrade to transmission links between New Brunswick and PEI, policymaking in the region is still largely undertaken on a Province-by-Province basis.

At a high level, the Maritime electricity system alone features three different electricity grids, five utilities and approximately a hundred power plants all within an electricity system of just over 6,000 MW. This presents significant challenges not only for power system efficiency; it also suggests a sub-optimal level of integration in the bulk power system in the region. While the development of Muskrat Falls will likely act as a catalyst for further system integration, by linking the Newfoundland and Labrador system with the Maritime Provinces, it will take greater cooperation for the full benefits of this integration to be achieved.

Nova Scotia currently has three major transmission interfaces, one linking Cape Breton to the rest of the Province, the other two splitting at Onslow to meet both Halifax and New Brunswick respectively. On July 20 2010, NB and NS announced that a new 345kV transmission line between the two provinces was being discussed with a transfer capacity of approximately 500 MW.

[37] Weil, G. (2003) "The Atlantica Power Market: A Plan for Joint Action," AIMS, Available at: http://www.aims.ca/site/media/aims/weilfinal.pdf

Figure 4-12. Transmission Map of Nova Scotia



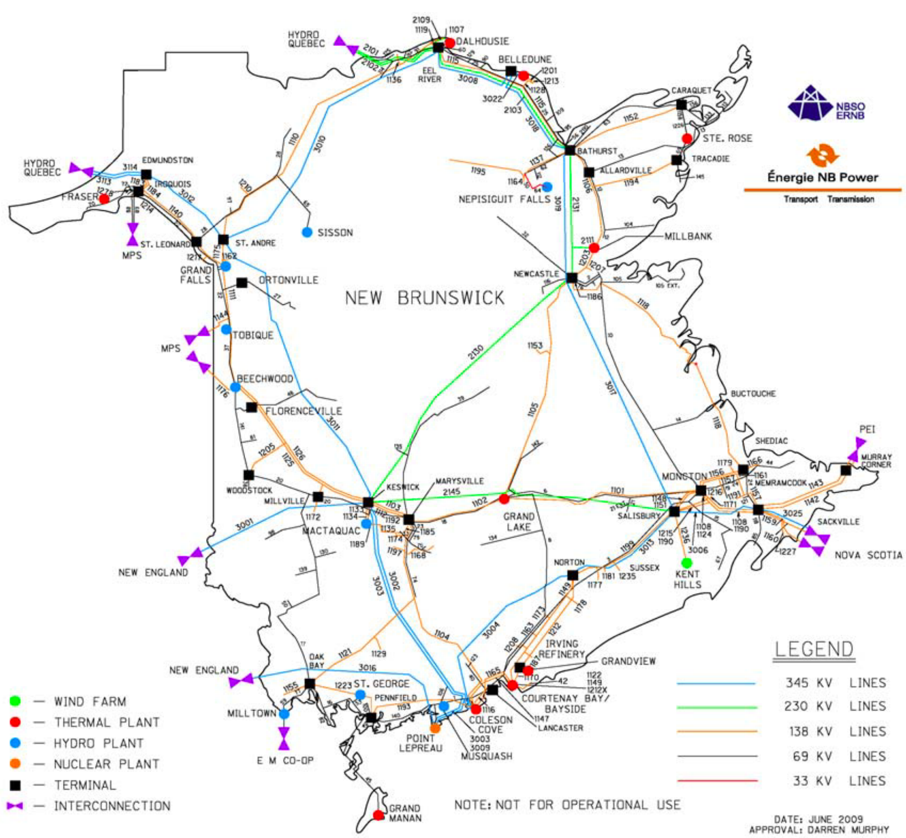
Source: SNC Lavalin 2009

Also, the Province is connected to New Brunswick via one 345kV line, and two 138kV lines for a total export capacity of 350 MW, and an import capability of approximately 300 MW. Despite this, Nova Scotia relies on NB at times for upwards of 10% of its in-Province demand, which means that any interruption to the primary 345kV intertie poses a tangible risk to electrical system reliability to many NSPI customers. Expanding this intertie would provide not only increased reliability and robustness for the NS system; it could provide value for New Brunswick as well, by boosting its ability to import power from Nova Scotia to meet load growth in the Moncton area, particularly during the winter months. Expanding the NB-NS intertie could also enable NSPI to import power from the Bayside Power Plant in Saint John, owned by NSPI's parent company, Emera, or from existing or future New Brunswick generation capacity, boosting system reliability and reducing the risks of interruption on both sides of the provincial border.

As highlighted in the section above, Nova Scotia also has significant coal and heavy fuel oil-fired generating capacity that it seeks to phase out in the years ahead. This will create a demand for greater electricity supply resources, whether domestic or imported. Regardless of the final decision on the Muskrat Falls project, Nova Scotia stands to benefit from greater interprovincial power flows. If the project proceeds, Newfoundland and Labrador will be the first recipient of Muskrat Falls power. Nova Scotia will also receive its allocation at in-service; if the project does not proceed, it will need to explore other opportunities to purchase or develop clean and renewable resources. While part of this can be met from existing policies and programs such as tendered wind and biomass projects, as well as the Province's recent COMFIT program, it is likely that it will need additional power from its neighbors to maintain system stability. This makes Nova Scotia a key player in determining the nature, scale and timing of discussions aimed at increasing interprovincial electricity trade.

On the northwestern front of the Maritime region, New Brunswick has approximately 1,100 MW of intertie capacity with Quebec, with one major intertie in Campbellton and another near Eel River, which is soon likely to be upgraded. The import transfer capability is 1100 MW while the export capability stands at 770 MW. However, the above-cited constraints on exports from NB to NS remain, and will likely need to be addressed to increase such power flows. In this area, New Brunswick will assume an important role and could ultimately help wheel power from Quebec to supply in-Province loads in the winter and eventually on to Nova Scotia, if the latter is in need of additional supplies to meet its energy and environmental targets.

Figure 4-13. Transmission Map of New Brunswick



Source: SNC Lavalin 2009

This notwithstanding, concerns remain over the recent shift in direction in New Brunswick, a key player in the region due to its strategic geographic location as the interface between the Atlantic Provinces and the U.S. Northeast. New Brunswick's recent *Energy Blueprint* has been identified as a turn inward, a shift toward focusing more on in-Province dynamics than on regional cooperation and collaboration.[38]

In parallel, some have argued for developing a regional or 'Maritime System Operator' that could provide coordinated balancing and load following services for the Maritime region.[39] A regional system operator could provide a more efficient and economic structure to facilitate interprovincial power flows. More specifically, it could help avoid "rate pancaking", which negatively impacts the economics of cross-provincial electricity trade. Paying for multiple transmission tariffs along the way makes the case for interprovincial flows, and by extension, for power exports more challenging to make. In addition to streamlining the tariff system, a regional system operator that had independence from individual provinces' political decision-making could improve market access for independent producers.

While the possibility has been discussed for over a decade, the initiative to develop a regional system operator has made little progress. It remains possible that if the Muskrat Falls project proceeds according to plan, the possibility of a sub-sea cable between Nova Scotia and New England could become more appealing, as it would help avoid tariff stacking and circumvent lengthy over-ground transmission expansions.[40] However, in light of recent developments, any discussion of such an export route remains speculative at best.

Turning to the U.S. side of the equation, due to the completion of a recent transmission project in 2007, New Brunswick now has two 345kV lines into Maine, linking it with the New England market. While rights to the new 345kV line's capacity have already been purchased, some additional developments are underway south of the border. As previously discussed, Maine has recently embarked on a $1.4 billion investment program for Maine's transmission system. The development plan is scheduled over five years, from 2009 to 2013, and involves the construction of six new substations, upgrades to more than 40 existing substations, as well as the addition of 700km of new transmission lines throughout the state of Maine.[41]

The addition of a new 345kV line south of Orrington, ME is also included as part of the MPRP plan, as are additional upgrades on existing substations. Although still under study by ISO-NE, this transmission project is estimated to increase the ability of the bulk power system to move power from the Northern Maine system to the rest of New England by approximately 150 MW.[42] While further bottlenecks in the New England system remain, the development of this intertie south of Orrington could eventually help facilitate the development of a regional power strategy between Maine, New England, and Atlantic Canada.

On the other hand, the Maritimes region has the opportunity to secure significantly more power in the years ahead, from a combination of Lower Churchill, New England, and even Hydro Quebec. Any of

[38] Weil, G. (2011) "A New Plan for NB Power: Analysis and Comment," Atlantic Institute for Market Studies (AIMS), Available at: http://www.aims.ca/site/media/aims/A%20New%20Plan%20for%20NB%20Power.pdf
[39] Weil (2003).
[40] SNC Lavalin 2009. Transmission and System Operator Options for Nova Scotia, Accessed September 15th 2011 at: http://www.gov.ns.ca/energy/resources/EM/renewable/NS-Transmission-SO-Options.pdf
[41] See http://www.mainepower.com/index.htm for further details.
[42] See ISO-NE's filing to FERC in Docket No. ER12-757-000, dated February 13, 2012.

these options could enable the Maritime Provinces to phase out some existing fossil fuel generation, while stabilizing rates in the years ahead. If this remains the case, the region's ability to market its power in an environment of abundant electricity supplies may be limited, at least in the near term.

One significant challenge that remains is the difficulty of lining up both the political and the technical (i.e. construction) timelines on cross-border energy initiatives like the AEG initiative. There are times when the technical, pre-feasibility work is well ahead of the politics and others when the politics are well ahead of the technical aspects. This will continue to be a challenge both for boosting interprovincial electricity flows, as well as for any power export strategy targeting the New England market. Making the case for greater interprovincial power flows will therefore likely require a clearly articulated vision of the shared value that such an approach can create.

History suggests that provinces will only cooperate, and truly "buy-in", if there is mutual gain. Given that greater interprovincial power cooperation is likely necessary for a successful New England export strategy; this puts a high premium on greater collaboration.

5. Conclusions on Market Opportunities

Navigant was retained to assess and quantify opportunities for both short-term and longer-term clean and renewable electricity exports (including associated renewable energy credits) from Atlantic Canada to New England; and assess opportunities for increasing the flow of clean and renewable energy within Atlantic Canada based on the concept of a more fully integrated Atlantic Canadian electricity market. Based on the above objectives, Navigant prepared this study to assess the potential export opportunities for clean and renewable energy. As part of this assessment, the following factors were analyzed: 1) current and anticipated future regional market demand drivers, 2) market barriers to the movement of clean and renewable energy within Atlantic Canada and New England, and 3) regulatory issues and considerations.

Based on the above identified factors, regulatory and market drivers, and the defining characteristics of the New England market, Navigant makes the following observations related to the opportunity for exports of clean and renewable energy to the New England power market:

1. There are three distinct "markets" for clean and renewable energy in New England: 1) the New England energy market; 2) the New England capacity market; and 3) the various state Renewable Energy Credit (REC) markets. Generally speaking, the energy market is accessible to any provider that can physically deliver electricity into New England and, similarly, the New England capacity market is accessible to any provider with a firm transmission path into New England. The rules for the individual state REC markets vary from state to state depending on each state's Renewable Portfolio Standard (RPS), particularly with respect to the type of renewable energy that is eligible to participate in the market.
2. The New England energy market has a significant amount of combined cycle natural gas capacity. Due to the discovery of unconventional gas resources, gas prices are low, and are projected to remain low for the foreseeable future. This has resulted in natural gas being on the margin for over 70% of the time. For example, with an average historic market average of 8,600 Btu/kWh and a natural gas price of $5/MMBtu, wholesale electricity market prices would be about $43/MWh (USD).
3. The New England capacity market has a significant surplus of capacity and is projected to remain in surplus until the end of the decade. This is the result of the implementation of a forward capacity market (FCM), and rules that support demand response resources competing against generation resources and imports to compete for a capacity supply obligation. It is expected to result in capacity prices that are well below the cost of new entry.[43]
4. The investment required for complying with some or all of the forthcoming environmental regulations could make a number of plants candidates for retirement. These plants include older steam coal, gas, oil units that are marginally economic and at risk of retirement given their limited

[43] ISO-NE and the NEPOOL market participants are currently evaluating alternative capacity market frameworks for the New England capacity market. These discussions are taking place as part of confidential settlement discussions resulting from FERC's Order in Docket No. ER12-953. Based on the limited information available on the ISO-NE website, the redesign efforts are exploring a number of options, such as demand curve and mechanisms to reduce price volatility.

operation. The removal of 3,500 MW of such capacity from the market would, as ISO-NE has indicated, eliminate much of the surplus capacity.

5. Current RPS policies provide incentives for renewable generation. There are no specific requirements, policies, or incentives for clean energy (e.g., large hydro and nuclear power), and the region does not distinguish between clean resources and other resources, such as natural gas plants, that meet the federal and state emission regulations. The PTC, if extended, would provide a competitive disadvantage to the AEG initiative.
6. New England's LSEs are currently relying on a mix of renewable resources located in New England, New York and Canada to meet their RPS requirements. New England is not expected to have enough "local" renewable resources to meet future RPS requirements. New England will need to import RECs to meet its future RPS requirements.
7. Large hydro cannot participate in the current RPS programs. There have been proposed changes to the RPS programs in Maine, Connecticut, and New Hampshire for allowing large hydroelectric generators to qualify. However, these legislative changes have either died due to unresolved differences or have been tabled for later discussion.[44] Maine currently allows hydroelectric resources of up to 100 MW to participate in its RPS Program and Vermont allows hydroelectric resources of any size to count towards its SPEED Program renewable energy goals.
8. There have been few long-term contracts offered to renewable energy projects in New England, and no long-term contracts offered to projects located outside of New England. If regional project development stalls and demand exceeds supply, long-term contracts could be offered to projects outside of New England to ensure compliance.
9. Maine is currently export constrained, with an abundance of natural gas-fired generation capacity. This has led to low energy prices, lower capacity prices, and reliability issues. The proposed transmission projects are being developed to address reliability concerns, and do not explicitly address the export constraints between New Brunswick and Maine or between Maine and the rest of New England.
10. Through various transmission service, access and rights agreements with Emera, Nalcor will have access through Nova Scotia and New Brunswick into the New England markets upon completion of the Muskrat Falls hydroelectric and associated HVdc transmission (Labrador-Island Link and Maritime Link) projects. In combination with the transmission access it currently has through Quebec, these agreements will allow Nalcor to sell any available energy and capacity into the New England energy market that is not utilized by Nalcor or committed for delivery into Nova Scotia. If the electricity available from Nalcor is eligible to participate in any of the state REC markets, it would also be able to access these markets.
11. Hydro Quebec is currently well positioned to sell into the New England market and its favourable market positioning is expected to continue into the future. It has transmission access into New England, surplus energy and is building additional hydroelectric generation facilities.

Based on the above observations and findings, there are two critical issues that must be addressed to maximize the New England market opportunity for Atlantic Canada clean and renewable electricity

[44] Recent legislation to eliminate the 100 MW limit on hydroelectric resources died on April 13, 2012. The bill died due to unresolved disagreements between the House and the Senate.

exports. First, the transmission capability from Atlantic Canada to New England is presently limited. The transmission infrastructure will need to be expanded to support significant long-term exports into New England. Second, large-scale hydro currently does not qualify to participate in state-mandated RPS programs. Legislative changes would need to be made to these programs to enable participation of Atlantic Canada's hydroelectric generation facilities. However, it is important to recognize that Vermont and Massachusetts have defined goals for "alternative" energy that may provide opportunities for Atlantic Canada's hydroelectricity facilities, but no penalties have been established for non-compliance with these goals (in contrast to the mandated RPS programs that have established penalties for non-compliance).

March 30, 2012

Atlantic Energy Gateway Report on Regional Electricity System Operations

MARTILLAC LIMITED and THOMPSON & ASSOCIATES

APPENDICES

Executive Summary

- The Atlantic Energy Gateway (AEG) is an Atlantic Canada electricity and clean renewable energy project funded and coordinated by the Federal Government Department of Natural Resources Canada and The Atlantic Canada Opportunities Agency, with participation from the governments of the four Atlantic Provinces, four of the major regional utilities, and the Region's two system operators.
- The AEG is focused on contributing to achieving greater regional cooperation, benefits, and efficiencies among the various participants in the electricity and clean renewable energy sectors.
- The Atlantic Canada electricity industry can be described as three distinct systems: the Maritime Provinces system consisting of New Brunswick, Prince Edward Island, and Nova Scotia; the Island of Newfoundland; and Labrador.
- Electricity demand in the region is growing slowly and there is overcapacity in current generating capacity, which when combined with proposed new power projects, the expansion of energy efficiency programs, and provincial policies for clean renewable energy levels, increases the uncertainty for the outlook of the region's electricity operations.
- The profile of the Atlantic region electricity industry consists of crown-owned utilities in NB and NL, investor-owned utilities: NSPI in NS, and Fortis's subsidiaries in PEI and its retail distribution utility on the Island of Newfoundland. There are two system operators: the functionally unbundled NSP System Operator, and the independent NB System Operator. Each of the provinces has a provincially legislated utility regulator, and the federal government has the National Energy Board.
- Atlantic Canada is a relatively small electricity marketplace with approximately 8900MW of generating capacity, not counting the Upper Churchill Falls output of 5428MW, which is mostly exported to Quebec. Peak load demand for the region in 2010 was approximately 6700MW or 75% of capacity.
- The Atlantic region, like other jurisdictions, has introduced policies and legislated rules that relate to cleaner sources of energy and reduced impacts on air emissions, and these policies and rules are beginning to have an impact on the existing portfolio of generation assets in

all four Atlantic Canada provinces and on electricity costs, on future planning for new generation, and also on the operations and requirements of a regional transmission system.

- This Paper contains a description of the regulatory systems in place in the Atlantic Provinces, and also other relevant regulators including FERC, NERC, NPCC, and NEB. Increasing cooperation and coordination in the Atlantic Provinces will require the examination of a number of approaches to system operations in the northeast region of North America.

- Proposed new developments such as the Labrador Muskrat Falls hydro project, increased renewable power, expanded regional transmission between NB / NS, between NL / NS and PEI / NB, plus the implementation of FERC Order 1000 dealing with regional and interconnection planning, will likely require individual or multiple jurisdictions to review various components of the regional electricity system.

- As the Atlantic Provinces and utilities look to the future of system operations, the completion of new and expanded transmission capacity and linkages will be a very important factor in determining the needs for greater regional cooperation and shared opportunities to increase efficiencies and generate savings for consumers. A number of approaches to systems operations could be considered, collectively and individually, in addition to the changes that are currently underway with the “status quo”: 1.) enhanced regional systems coordination; 2.) independent system administrator; and 3.) independent system operator.

- Planning in the Atlantic region is primarily within the control of the individual utilities, except in NB where the NBSO currently has the legal responsibility as resource planner and reliability planning coordinator. However, NBSO’s role will be significantly changed under the recently announced NB “Energy Blueprint” which commits to integrating the independent system operator back into NB Power.

- The planning function is a key ingredient of the United States FERC and NERC regulatory planning functions, where significant effort is being placed on creating a standard that strengthens interconnection compatibility and reliability. Therefore as a member of NERC and being interconnected to the US system, the Maritimes Region must also meet the reliability standards of NERC.

- Increasing regional electricity and clean renewable energy cooperation could achieve potential efficiencies and cost benefits to consumers and industry, and expand economic opportunities and benefits for the region. Implementation considerations and some areas that could be reviewed in exploring increased coordination are:

    i. existing generation and transmission structures and policies;

    ii. examining opportunities for regional planning for expanded renewable energy sources to maximise market competitiveness;

    iii. planning for future system operations on a regional basis; and

    iv. harmonizing certain regulatory functions, while ensuring the Atlantic region maintains its close regulatory, reliability, and business relationships with the Northeast USA and related agencies.

- Increasing cooperation and coordination by the Atlantic Provinces' electricity sectors could become the start of an Atlantic Canada power market that is more competitive, both locally and internationally.

1. Introduction

The Atlantic Energy Gateway ("AEG") is an Atlantic Canada electricity and clean renewable energy project funded and coordinated by the Federal Government Department of Natural Resources Canada ("NRCan") and The Atlantic Canada Opportunities Agency ("ACOA"), with participation from the Governments of New Brunswick ("NB"), Prince Edward Island ("PEI"), Nova Scotia ("NS"), and Newfoundland and Labrador ("NL"); four of the region's major electrical utilities: New Brunswick Power Group of Companies ("NB Power"), Maritime Electric Corporation ("MECL"), Nova Scotia Power/Emera Inc. ("NSPI/Emera"), and Nalcor/Newfoundland and Labrador Hydro Corporation ("Nalcor/NLH"); and the region's two system operators: New Brunswick System Operator ("NBSO") and Nova Scotia Power System Operator ("NSPSO").

The AEG is focused on contributing to achieving greater regional cooperation, benefits, and efficiencies among the various participants in the electricity and clean renewable energy sectors through increased collaboration, discussion and analysis of existing utility assets, and future requirements including additional clean renewable energy resources for regional and export purposes.

The AEG participants have worked collaboratively over the past two years sharing existing information pertaining to the electricity systems, development of Atlantic Canada's clean renewable energy resources, and where necessary, undertaking new analysis to improve the understanding of the region's electricity industry.

Some of the major components of the AEG work included: workshops on individual energy components in each of the four Atlantic Provinces; working committees on functional sectors such as transmission, resource generation, system operations; meetings and conference calls; participation by industry experts; and a number of external studies designed to provide a strategic and factual foundation on topics such as renewable energy financing, renewable energy R&D, supply chain development, and a study of the Eastern Canada and Northeast United States marketplace for electricity.

This Overview Paper supports the belief that the Atlantic Provinces have the opportunities and the natural resource base to expand its diverse clean and renewable energy potential, and to improve the efficiencies of its existing electricity generation and transmission assets, for both domestic and export markets. The region's portfolio of existing and potential indigenous energy assets includes large scale hydro, natural gas, and traditional clean renewable energy sources such as wind, solar, tidal, biomass, and small-scale hydro, as well as nuclear, coal and oil-fired generation assets.

Overview Paper Methodology

This Overview Paper describes the main characteristics of the current Atlantic Canada electricity system, including Eastern Quebec and the appropriate interconnected areas of the Northeastern United States. It focuses primarily on the organizational and system operations structures, relationships, regulatory, and administrative elements that currently comprise the electricity sector of the three Maritime Provinces and Newfoundland and Labrador. The Paper also presents an overview of the main policy and implementation considerations that have been identified in assessing areas and alternatives for increased Atlantic regional electricity cooperation and expanded clean renewable energy opportunities

The Paper utilizes relevant information and analyses provided by the provincial governments, utilities and system operators in the various AEG workshops and meetings.

1). PROFILE OF THE ATLANTIC CANADA ELECTRICITY INDUSTRY

The Atlantic Canada electricity industry can be described as three distinct systems:

1.) the Maritime Provinces' system consisting of New Brunswick, Prince Edward Island and Nova Scotia, where NBSO is the Regional Reliability Coordinator for the three systems plus Northern Maine, since that region of Maine is connected to the rest of the United States transmission system though the NB Power system.

2.) The Island of Newfoundland, which is currently isolated from both the mainland of Canada and from Labrador.

3.) Labrador has a domestic electricity network that serves a very spread out, coastal, and interior load for a small population and industrial base. It also has the huge Upper Churchill Falls hydropower plant (5428MW) that supplies the iron ore mining industry of Labrador City-Wabush, while the vast majority of the Upper Churchill power is exported to Hydro Quebec under a long-term contract.

Ownership of the main utilities in Atlantic Canada varies: crown corporations operate in New Brunswick (NB Power), and in Newfoundland and Labrador there is both a crown corporation (Nalcor and NLH) and an investor-owned utility, Newfoundland Power ("NP"), a subsidiary of publicly listed Fortis Inc. ("Fortis"); in Nova Scotia, Emera is an investor-owned corporation and NSPI is its 100% owned subsidiary; and in Prince Edward Island the main utility is MECL, a subsidiary of Fortis.

In addition to the main regional utilities, there are a number of municipal utilities, specific industry power generators (e.g. Kruger Paper in Deer Lake, NL), and a growing number of independent power producers for renewable energy, mostly wind.

Some Factors Impacting the Regional Industry

Atlantic Canada's combined population in the four provinces is 2,357,000 or 6.84% of Canada's population of 34,483,000. The cumulative growth rate for Atlantic Canada's population in the past 5-years is 1.35%, less than one third of Canada's 4.72% percentage growth.

The current population totals by Atlantic Province are:

a) Nova Scotia - 945,400

b) New Brunswick - 755,500

c) Newfoundland and Labrador - 510,600

d) Prince Edward Island - 145,900

The population growth rates within Atlantic Canada during the period 2007-08 to 2001-2012 ranged from 5.6% in Prince Edward Island to .8% in Newfoundland and Labrador.

Economic performance in Atlantic Canada has become a "tale of two economies" to quote the Atlantic Provinces Economic Council. Newfoundland and Labrador's extensive mining and oil and gas resources are driving growth rates that are above the national average, while the three Maritime Provinces are lagging the Canadian averages. This is creating a macro employment impact where NL will be struggling to find enough skilled workers, and PEI, NB, and NS may have less employment growth.

The trends in macroeconomics, population, and demographics in the Atlantic Provinces have implications for the demand forecasts for electricity. Electricity demand in the region is growing slowly. When combined with the expansion of energy efficiency, demand side management programs, and the adoption of much more aggressive provincial policies for "clean renewable energy levels and improved air emissions", these factors increase the uncertainty of the outlook for the electricity operations of the region as a whole.

Overview of the Four Provincial Electricity Sectors

New Brunswick

NB Power is a provincial crown corporation and is the largest of 4 distribution utilities in the Province of New Brunswick directly serving approximately 330,000 customers. The recent "Energy Blueprint" released by the provincial government signals a return to a fully integrated utility structure. Currently NB Power's responsibilities and operating conditions are established by the Electricity Act and related legislation. Regulatory oversight of the electricity industry in NB is provided by New Brunswick Energy and Utilities Board ("EUB"). The other 3 distribution utilities service specific municipalities serving markets from 36,000 customers by Saint John Energy to

1,000 customers with Perth Andover. The City of Edmundston with 5,700 customers operates its utility as part of a municipal government including generation capacity from small hydro. Saint John Energy purchases all its electricity from NB Power; Edmundston buys what it needs beyond its own production from NB Power; while Perth Andover purchases its energy from Algonquin Power's local Tinkers dam. Ownership of the municipal utilities is held by individual local governments.

NB Power provides its residential, commercial and industrial customers with electricity generated at 14 facilities including a Candu6 nuclear facility at Point Lepreau. The company generating capacity consisting of: 1728mw of thermal, 889MW of hydro, 525MW of combustion turbine capacity, and 635MW of nuclear capacity for total capacity of 3,777MW. There are also a number of private generation facilities that provide through power purchase agreements up to 721MW of energy to NB Power. These private facilities include wind, biomass, hydro, and natural gas facilities within the province, and additional wind from connected jurisdictions.

There are approximately 370,000 customers in the province, direct and indirect through municipal utilities, serviced by an extensive system with 6,703km of transmission lines, 46 terminals and switchyards, and 20,030km of distribution lines. NB Power is also active in the import/export market for electricity through interconnections with New England, Quebec, Nova Scotia, and Prince Edward Island.

The policy direction in the Energy Blueprint would result in significant changes in the operations of the provincial electricity system. It outlines changes in the regulatory role of the EUB, and a resulting expansion in the operational information that NB Power will have to present regularly to the EUB. These changes include submitting an Integrated Resource Plan; presenting all proposed rate changes for approval; and including generation operations in future rate change hearings. The Energy Blueprint also commits to integrating the current independent electricity system operator, NBSO, back into NB Power.

Nova Scotia

NSPI, a subsidiary of Emera, is a vertically integrated investor-owned utility that produces approximately 95% of the electricity consumed in Nova Scotia. NSPI is regulated by the Nova Scotia Utility and Review Board ("UARB"). In addition to NSPI, the Nova Scotia electricity sector is comprised of 6 small Municipal Utilities that buy almost all of their power from NSPI, and a number of Independent Power Producers ("IPP"), mostly generating wind power, and some hydro.

NSPI generates approximately 75% of its power from plants using imported coal and petroleum-coke, and one oil/natural gas plant. It generates 15% from its hydro plants and one tidal plant, and the balance from renewable energy, mostly wind, which on an average windy day will produce 10-

15% of NSPI's production. Total NSPI revenues in 2010 were $1.167 billion and profit after taxes were $121 million.

The transmission system of NSPI is 5,200 km and distribution lines total approximately 26,000km, serving 490,000 residential, commercial and industrial customers. Total power generation capacity from NSPI's fleet of oil, gas, coal, hydro, biomass and wind units is 2368MW, plus an estimated 186MW from IPPs. The NSPI system peak production in 2010 was 2121MW, and the low for the year was 771MW. The transmission inter-tie between Nova Scotia and New Brunswick historically has had export capacity of 350MW and import capacity of 300MW; however, in recent years the load growth in the Moncton, NB area in particular has significantly reduced the "firm transfer" capability of that interconnection.

NSPI's recent growth in electricity consumption has been in the range of 0.5 to 0.9 per cent, lower than the long-term historical average.

Prince Edward Island

MECL is a wholly-owned subsidiary of Fortis Inc. and operates under the provisions of the Electric Power Act and the Renewable Energy Act, and is regulated by the Island Regulatory and Appeals Commission ("IRAC"). MECL owns and operates a fully integrated system that provides the generation, transmission, and distribution of electricity to customers throughout Prince Edward Island, except for the City of Summerside.

The City of Summerside operates its own distribution utility with its own diesel and wind generation. In addition, it purchases electricity, under term contracts, from NB Power and NSPI, and from wind farms owned by private operators and the PEI government crown corporation, PEI Energy Corporation.

MECL sources the majority of its electricity from off-island sources which is transmitted over two submarine transmission cables under the Northumberland Strait from New Brunswick. The current import-electricity supplier is NB Power. MECL also purchases up to 52MW of wind generation from PEI Energy Corporation's North Cape and Eastern Kings wind farms, and has 149MW of oil and diesel fuelled capacity for peak periods and security from transmission disruptions from the mainland.

There are approximately 5,000 kilometres of power lines on Prince Edward Island with 4400km for distribution and 600km for transmission.

PEI has some of the highest electricity rates in the country and has taken steps in 2011 to manage the cost by entering into an "Energy Accord" between the provincial government and MECL. Under the Energy Accord electricity rates will be reduced by 14% due to a combination of the provincial government taking on responsibility for funding the deferral costs associated with the PEI commitment to the Point Lepreau nuclear plant (5%), and the terms of a new Power Purchase Agreement with NB Power.

The PEI government has identified total wind potential of 500MW and is working to expand wind-powered generation through the PEI Energy Corporation. In order to support greater wind generation, increased demand and reliability, the PEI government is in negotiations with the federal government to construct a third interconnection transmission line from PEI to the NB mainland.

Newfoundland and Labrador

Nalcor is the prime energy crown corporation for the Province of Newfoundland and Labrador. It has three subsidiaries that are in the electricity sector: NLH, Churchill Falls (Labrador) Corporation ("CFLCo"), and the Lower Churchill River Power Project (Muskrat Falls and Gull Island). NLH is the only regulated utility in the Nalcor group and is regulated by the Board of Commissioners of Public Utilities ("PUB") on the basis of cost of service and an approved return on rate base.

The main generator of power for domestic consumption in the province is NLH which has 1635MW of capacity, plus power purchase agreements for approximately 54MW of wind. NLH supplies the industrial load and also has 35,000 mostly rural retail customers in both Labrador (11,300) and on the Island (23,700). Most of NLH's generated power is supplied as wholesale energy to NP, a subsidiary of Fortis that has been in business for 125 years. NP buys 93% of its energy from NLH to service its 243,000 residential and commercial customers, while the remaining capacity of 140MW is generated from its own plants and delivered over its 11,000km of distribution and transmission lines.

NLH's generation comes from its 9 hydroelectric plants (939MW), one oil-fired plant (490MW), 4 gas turbines (150MW) and 25 diesel plants (58MW). NLH operates approximately 3750 km of transmission lines, while most of the Province's distribution lines are owned and operated by NP.

Nalcor owns 65.4% of CFLCo, which owns a large hydropower plant in Churchill Falls, Labrador, and Hydro Quebec owns the remaining equity. CFLCo has an 11-unit total capacity of 5428MW and annual power generation of 34 terawatt hours. Most of CFLCO's energy is sold to Hydro Quebec under a 1969 Power Contract that has a 40-year term to 2016 and a 25-year renewal to 2041.

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Nalcor is also the owner and developer of the Lower Churchill River Power Project which consists of the Gull Island site, 225km downstream of CFLCo (2000MW), and the Muskrat Falls site which is 60km downstream of Gull Island (824MW). The Muskrat project is under active development and in the environmental approval and engineering design stages, with in-service power targeted for 2017.

In November 2010 Nalcor and Emera announced a project partnership and a "Term Sheet" for the $6.2 billion Muskrat project. The project consists of: (1.) the 824MW (4.9 terawatt hours) generation plant at Muskrat Falls; (2.) an 1100km, 900MW transmission line from Muskrat Falls, Labrador by a 30km sub-sea cable under the Strait of Belle Isle, and a new transmission line across the Island to just outside St. John's; and (3.) a 180km, 500MW sub-sea cable across the Cabot Strait to Cape Breton, Nova Scotia to connect with the NSPI transmission system. In addition, Emera has assigned to Nalcor its "transmission rights" to 265MW of capacity on the NB transmission system that links to the New England marketplace. The Government of Canada has announced that it will provide a "loan guarantee or equivalent" to the Muskrat Falls project.

The Term Sheet between Nalcor and Emera outlines the expected consumption of the 824MW of capacity at Muskrat Falls to be: 20% or 170MW (.98 terawatt hours) to Emera for 35 years; decommissioning of Hydro's 490MW oil-fired plant at Holyrood and replacing it with Muskrat hydropower; leaving approximately 40% or 2 terawatts hours of energy annually for export to Canadian provinces and the Northeast USA, or new economic development opportunities in Labrador or on the Island.

Atlantic Region Regulatory Systems

Each of the four Atlantic Provinces has a regulator for its electricity sector that in some cases also regulates a number of other utility-type functions such as bus transportation, natural gas rates, automotive insurance rates, certain municipal services, petroleum pricing, and energy efficiency programs, and cost recovery. The provincial regulators are: Nova Scotia-UARB; New Brunswick-EUB; Prince Edward Island-IRAC; and Newfoundland and Labrador-PUB. The federal regulator for certain interprovincial and international electricity transmission and sales purposes is the National Energy Board of Canada ("NEB").

A summary of each of the provincial regulators and the NEB is contained in Schedule 1.

Regional Environmental and Renewable Policies, Rules, and Targets

The electricity sectors in Canada, North America, and in many parts of the world have undergone a significant shift in public policy and regulation in recent years as it relates to cleaner sources of energy and reduced impacts on air emissions. These policies and legislated rules will be having a significant impact on the existing portfolio of generation assets in all four Atlantic Canada provinces, on future planning for new generation, and also on the operations and requirements of the transmission systems.

The majority of growth in new generation capacity in the past five years in the Atlantic region has come from the addition of wind power, and a small amount from natural gas. No new coal or oil-fired generation has been built. In the near term, new clean renewable energy capacity is expected to come from wind power, biomass, solar, tidal, and the proposed 824MW hydropower plant on the Lower Churchill River in Labrador at the Muskrat Falls dam site.

Some of the key challenges for the regional electricity industry surround the need to reduce its dependence of fossil fuels in order to meet Greenhouse Gas ("GHG") policies that have been established at both the provincial and federal levels and to achieve the clean energy or renewable energy portfolio percentages that have been set. Since there are different mixes of generating assets in each of the Atlantic Provinces, addressing these challenges will not be the same for every province, and in some cases the challenges themselves will continue to be different. However, there would appear to be a number of areas where increased cooperation and the possibility of integrating certain electricity systems and assets could improve the overriding objective of cleaner energy sources and relatively more stable customer rates.

A summary of the environmental and renewable energy policies for each of the four Atlantic Provinces and of the recent federal government coal-generated power regulations, are contained in Schedule 2.

2). Regional Electricity System Operations

The electricity sector in North America continues to evolve from a collection of isolated, independent systems to a network of interconnected high voltage transmission systems. Increased interconnection has resulted in expanded regulatory oversight to reduce the potential of power outages occurring and spreading between jurisdictions. The need for expanded and more reliable interconnection was highlighted by the wide power outage of August 2003 when a rolling power black-out started in Ohio and spread all the way to New York through Ontario and numerous other states. The entry point from Maine through New Brunswick was able to prevent the spread of the black-out to the Maritime Region.

In Canada, the provinces have the authority to regulate the electricity sector within their boundaries and the federal government deals mainly with certain international transmission activities. The broader North American regulatory and reliability issues are dealt with mainly in the United States where the Federal Energy Regulatory Commission ("FERC") has the prime authority vested in it by the federal government. FERC and other regulatory agencies have established international approaches to the electricity sector focused on reliability, safety, and open access and include the North America Electricity Reliability Corporation ("NERC"), the Northeast Power Coordinating Council ("NPCC",) and the NEB.

A overview Note on the regulatory system affecting the Atlantic Provinces, including FERC, NERC, NPCC, NEB and other involved agencies, is contained in Schedule 3. This Note was developed for the AEG by the Nova Scotia Department of Energy in 2010, and while it is written from a Nova Scotia perspective, the information associated with the NSPI, NSPSO and the UARB could be largely applicable to all the regional jurisdictions seeking access to the US market.

NERC produced in 2009 Version 5 of its Reliability Functional Model, "Function Definitions and Functional Entities". The Model is intended to provide a framework for which NERC reliability standards are developed and applied. It is not a standard and does not have compliance requirements but serves as a guideline. The Functional Model describes a set of Functions that are preformed to ensure the reliability of the bulk electric system.1

These international regulators continue to add requirements to the bulk transmission system. An example is the July 2011 FERC Order 1000 which is focused on the transmission planning process and the approach FERC feels should be followed to secure the reliability of the North American transmission system.

1 http://www.nerc.com/files/Functional_Model_V5_Final_2009Dec1.pdf

Current Regional System Operations

There are a number of approaches to system operations in the northeast region of North America. These jurisdictions—Atlantic Provinces, Quebec, and New England—are connected and operate in a cooperative manner using different approaches. The ability to cooperate is tied to the international regulators requiring market standards to allow the movement of electricity.

A summary profile of regional system operations approaches in Atlantic Canada, Quebec and the Northeast USA is contained in Schedule 4. In brief:

- New Brunswick uses an independent system operator (NBSO) that serves as reliability coordinator for the Maritime Provinces region.
- Nova Scotia uses a functionally unbundled independent unit, NSPSO, within the utility NSPI that operates under a Standard of Conduct.
- Prince Edward Island uses a functionally independent unit within MECI, operated under a Standard of Conduct.
- Northern Maine utilities operate an independent system administrator (NMISA) with NBSO filling the role of Reliability Coordinator, Interchange Coordinator, and Balancing Authority.
- The Island of Newfoundland system has operating standards developed by NLH and administered by its system operators within the NLH Energy Control Centre.
- The Labrador system is operated by NLH using the same standards as the Island of Newfoundland.
- Quebec uses a functionally independent unit within Hydro Quebec operated under a Standard of Conduct with the Regie de l'energie which has been delegated, among other functions, responsibility for reliability coordination.
- New England uses an independent system operator (ISO-NE) that has responsibility for reliability market operations and planning for the six states.

These specific Standards of Conduct for NS and PEI were established to govern relationships that NSPI and MECL have with their transmission customers and potential customers, independent power producers, and includes detailed operating procedures and guidelines that cover the expected behaviour of employees of each utility and their affiliates. These Standards of Conduct are based on FERC Order 2004 and earlier Orders 889 and Order 888 regarding non-discriminatory transmission open access, i.e. OATT.

In most cases planning has remained the responsibility of the individual jurisdictions and utilities, with NBSO and ISO-NE having responsibility in New Brunswick and New England respectively, and the individual utilities being responsible in the other provinces.

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In the October 2011 New Brunswick's "Energy Blueprint", the government outlined the province's approach to energy development and management for the next ten years. As part of this policy, the government stated that many NBSO functions will be rolled back into the reintegrated utility, NB Power, and structured with a Standard of Conduct operating approach as is used elsewhere.

This new NB approach will result in the need for the region to determine how they will coordinate regional activities currently undertaken by NBSO. The establishment of system operations in NB Power could result in each of the provincial jurisdictions taking a similar approach of the provincial utility operating the transmission system under a Standard of Conduct.

The Atlantic region's electricity system operations could have a number of significant new developments in the next few years that may require individual or multiple jurisdictions to review various components of the regional system. Some examples of these factors include:

- The addition of new electricity generation from Muskrat Falls, tidal sites, wind, and upgraded hydro.
- Connection of Labrador to the Island of Newfoundland system and the Maritimes, thereby ending the current isolated system situation.
- The implementation of FERC Order 1000 which deals with an expanded approach to regional and interconnection planning.

The relatively small size of the Atlantic Canada regional electricity system with regard to generation capacity, load demand, and transmission highlights the need to examine all possibilities for regional cooperation and additional efficiencies.

System Operations Alternatives

As the Atlantic Provinces and utilities look to the future of system operations, there are a number of approaches to consider, collectively and individually. Regional cooperation and ccoordination can assist the review of reliability standards, compliance, planning and other functions outlined in the NERC Reliability Functional Model. The extent of any increased technical, policy and/or regional collaboration will depend on the utilities and governments assessing the importance of a number of factors and considerations, some of which are outlined in Section 4 .

The current "status quo" of the Atlantic region electricity system will not likely exist for much longer given the proposed restructuring of NB Power and elimination of the current scope of responsibilities for NBSO, and the probability that the Muskrat Falls hydropower project will proceed and result in significant changes to the transmission system and renewable energy portfolio because of the new high voltage transmission interconnections between Labrador and the Island of Newfoundland and also between the Island and Nova Scotia. The two most likely changes outlined above, plus slower market conditions for electricity demand, increased clean renewable energy sources, and the requirements to coordinate reliability standards with those of the USA, point in the direction of a changing "status quo" in the near term, and in the longer term, some evolving regional system operations coordination or cooperation arrangement or structure.

Outlined below are three alternative system operations approaches that could be considered for the region in the future.

Enhanced Regional Systems Coordination

Coordination and cooperation within the Maritime area and the Northeast USA have been underway for years. For example: coordinated emergency response, the Maritime Area Technical Planning Committee, the current AEG process, the multi-utility Power Shift Atlantic project, regional committees including NERC, the NPCC "Working Group on System Resource Adequacy", and the Northeast International Committee on Energy ("NICE") which is part of the Conference of New England Governors and Eastern Canada Premiers, focused on renewable energy. This broad range of electricity coordination occurs among utilities and provincial and federal governments, and the USA.

An interesting example of regional planning and policy_coordination at a government level can be seen in the New England States Committee on Electricity, or NESCOE.

> "*NESCOE represents the collective interests of the six New England states on electricity matters by advancing policies that will provide electricity at the lowest possible price over the long term, while maintaining reliable electric service and environmental quality*" *(http://www.nescoe.com)*

NESCOE is directed by Managers appointed by each of the six New England Governors and advances policies based on collective research currently in the areas of system planning and expansion, as well as resource adequacy. They work in a coordinated manner with the existing organizations and committees functioning in the region. Examples of their work include producing the New England Governors Renewable Energy Blueprint in 2009, commenting on national and international issues on behalf of the member states and providing comments on ISO-NE Draft Regional System Plan. The role and scope of NESCOE activities is established by state governors as they identify areas of common public policy interest.

NESCOE is a vehicle for government level planning and policy coordination with the technical coordination provided by ISO-NE. The NESCOE coordination and technical support model may have some future applicability to the Atlantic region. Such an organization would allow individual jurisdictions and utilities to continue to control their bulk transmission systems while having a common understanding and approach to identifying and reporting on potential common opportunities.

An approach as described above would allow utilities to examine services that are currently provided by the NBSO and the agreements it administers for utilities and regulators in the region—such as NSPI, NMISA, and MECL—and to assess whether enhanced interconnection and coordination agreements could produce regional system operations benefits in the future. This would include examining potential benefits that could be created from the proposed Nalcor/NLH new HVDC transmission system from Muskrat Falls to Nova Scotia by way of Emera/NSPI's proposed sub-sea transmission cable.

Cooperating on policy and enhanced technical coordination could provide the Atlantic region with an approach that provides value to the electricity and clean renewable energy sector without having direct involvement in the operations of the individual utility transmission systems. It could also provide governments and utilities with researched papers on policy initiatives, and technical and R&D reviews focused on topics such as improving the performance of the region's electricity market, and on some degree of regional planning, standards development, and compliance enforcement.

Independent System Administrator

Independent System Administrator ("ISA") is a term familiar to the Maritime Provinces' region because of the existence of the Northern Maine ISA ("NMISA") which provides select services to the utilities operating in those parts of Maine not connected to the rest of the State. The structure and the operating functions that are to be coordinated by an ISA are determined by negotiations among the affected utilities, regulators, and governments. There are no defined restrictions on what can be included in an ISA structure, including the possibility of incorporating an independent system operator role.

NMISA was established in 2000 in response to the development of FERC Orders respecting the ownership of integrated utilities, and the belief there should be separation and independence between the operation and ownership of generation and transmission functions. In Northern Maine this resulted in a number of small utilities that have transmission and distribution systems seeking a method of operating collectively in an isolated US region. These utilities currently have a combined peak load of 130MW.

The NMISA is the only example of a complete ISA system in North America and describes itself as follows:

> *"The NMISA, a non-profit entity responsible for the administration of the Northern Maine transmission system and electric power markets in Aroostook and Washington counties, with a load of approximately 130 MW. The NMISA is responsible for providing an independent, objective and non-discriminatory administration of all transmission access, transmission information access, and related functions, and will monitor and operate the markets in Northern Maine for energy, ancillary, and other services. The NMISA administers the transmission systems of the investor-owned and cooperatively-owned utilities in Northern Maine, and its members also include all municipally-owned utilities, generators, suppliers of energy, and large retail customers operating in the service area."*

NMISA entered into a Products and Services Agreement ("PSA") with NB Power in 2000, primarily because Northern Maine (N.ME") relies on NB Power for essential support as it is not connected directly to the New England transmission grid. The PSA ensured that N.ME could obtain balancing service, reliability and improved transmission access, notably with respect to tie line interruption. As the NPCC and NBSO developed, the operational terms of the PSA, though not technically abrogated, were replaced by a more integrated relationship between NMISA and NBSO. NBSO serves as the Reliability Coordinator and Balancing Authority for NMISA, both functions having been required by FERC/NERC. NMISA also is assigned its proportionate share of the operating reserve requirement of the Maritime Control Area. Power suppliers to N.ME are required to make their own transmission arrangements, and NMISA is responsible for ensuring adequate transmission in N.ME and the interconnections with NB Power.

An ISA-type structure allows individual system owners/operators to maintain operating control of their transmission systems while entering into agreements that establish an administrator, i.e. an ISA, to oversee agreements that establish rules agreed upon by participants in the system, including operators, utilities, governments and regulators. These agreements establish the rules, penalties, and roles of participants and other key elements of operating a system within the region. The role of an ISA could be expanded to be a more active participator in the operations of the electrical system, as noted in the Manitoba Hydro example below, or remain in a more administrative role as in N.ME.

Another example of a restricted operating agreement is the arrangement where Manitoba Hydro operates its system through a functionally independent system operator under a Standard of Conduct. However, it has established a regional operating relationship with the US Midwestern Independent System Operator ("MISO"). Under this MISO arrangement, Manitoba Hydro is associated as a Coordination Member with MISO, which by contractual agreement provides reliability coordination and regional planning services to Manitoba's provincial utility. This formal system coordination arrangement with MISO allows Manitoba Hydro to independently operate its system, while complying with North American standards that protect its position in the US market for the sale of surplus electricity.

There are other examples of multiple jurisdiction power cooperation structures such as the Nord Pool Spot group power exchange in Europe which originated in the Nordic countries of Norway, Finland, Sweden and Denmark starting with Norway in 1991 and now has market activities in many European markets. Nord Pool contributes to a more integrated and efficient energy market that offers its customers the highest standards and provides cost synergies. It is a model for a more connected and efficient European energy market whose vision is to stretch from Portugal to Finland.

In the Northeast USA, the original cooperation structure was the New England Power Pool ("NEPOOL") established in 1971, whose prime mission was "to ensure the reliability of the bulk power grid in New England and neighboring power systems at the lowest costs". NEPOOL was formed in response to the 1965 Northeast blackout, when the lack of shared resources and transmission management severely reduced reliability.

NEPOOL was known as a "tight power pool" where there was central dispatch of generating resources called economic dispatch and which allowed for the use of the lowest cost generation mix at any given moment. NEPOOL was also the control area for the New England region, ensuring that reliability was maintained at all times by having sufficient generating resources available.

The transmission system remained under the control of the individual transmission owners. A new generator was not allowed to connect to the New England grid unless its output could be dispatched anywhere in New England without degrading reliability. Some generators could be designated as "pool planned units" if they were considered to be necessary additions to the resources needed to maintain reliability.

The market was largely bilateral with buyers and sellers making their own deals. Utilities could also purchase through NEPOOL, especially for short-term needs. Thus, NEPOOL provided for the use of generating and transmission systems across six states and nine major systems to provide the lowest cost power supply and strong reliability. The NEPOOL structure created a basic open market without any utility which owned generation and/or transmission assets relinquishing control over its resources, except to meet NEPOOL requirements for ensuring reliability and dispatch both at a lower cost. NEPOOL and the transmission owners were FERC-regulated.

NEPOOL was later transitioned into the New England Independent System Operator ("ISO-NE"). ISO-NE took over the management of the transmission system and operation of the market, and

NEPOOL became the participants' committee of end-use customers, generators, and transmission owners for the regional stakeholders' consultations which are required by FERC.

Another example of cooperation is the currently evolving coordination of intra-hour revisions to "tie schedules" between New York and Quebec as part of a broader regional market initiative.

In summary, there can be significant operational benefits obtained from establishing a regional ISA, or some other system administrative and operations structure among a number of utilities that could focus on some or all of the following system functions:

- Planning for the area covered by the ISA agreement for transmission, reliability and resource requirements;
- Market design and administration including balancing mechanisms, reserve margins, economic dispatch, ancillary services, and resource/capacity adequacy;
- Tariff design to deal with issues including pancaking, treatment of losses, out charges, and cost allocation; and
- Regulatory oversight required by international and regional regulatory authorities.

Independent System Operator

An Independent System Operator ("ISO") is an organization formed to coordinate, control, and monitor the operation of the bulk transmission system within a single jurisdiction. Examples of an ISO exist in Ontario, Alberta, New Brunswick, and there is a multiple jurisdictional ISO in New England (ISO-NE). An ISO operates a region's electricity grid, administers the region's wholesale electricity markets, and provides reliability planning for the jurisdiction's bulk electricity system. The extent of an ISO's role is established through agreements with participants, or through legislation. The mission statement for ISO-NE can be summarized as follows:.

ISO-NE is*: through means including, but not limited to, planning, central dispatching, coordinated maintenance of electric supply, and demand-side resources and transmission facilities, obtaining emergency power for market participants from other control areas, system restoration (when required), the development of Market Rules, the provision of an open access regional transmission tariff (OATT), and the provision of a means for effective coordination with other control areas and utilities situated in the United States and Canada.*

The New Brunswick independent system operator, NBSO, currently has responsibility for a number of the functions described in the NERC Reliability Functional Model. NBSO has operating responsibility as "regional reliability coordinator" on behalf of the entire Maritime Region, and also performs, on behalf of PEI and N.ME, the interchange and balancing functions. On behalf of New Brunswick, the NBSO current responsibilities are:

1. Facilitate the operation of a competitive electricity market;
2. Direct the operation and maintain the adequacy and reliability of the system operator controlled grid and integrated electricity system;
3. Undertake and coordinate power system planning;
4. Develop and adopt mandatory reliability standards and criteria;
5. Perform functions such as the Reliability Coordinator for the Maritime Provinces and N.ME;
6. Be the Balancing Authority for NB-PEI-N.ME;
7. Do the administration of the OASIS for NB and NS;
8. Perform transmission operation functions on behalf of NB Power Transmission through an operating Agreement; and
9. Administer the NB Open Access Transmission Tariff (OATT) and is subject to EUB oversight for its revenue requirements.

In summary, NBSO's activities cover planning reliability, resource planning, market operations, transmission service, and transmission operations. These tasks are undertaken in most other provinces by the utilities with regular staff or in-house system operators.

The NB Energy Blueprint policy direction of establishing the system operation function inside NB Power leaves the regional provincial utilities with the similar basic structure for system operation. However, NBSO's current provision of the reliability coordination services is a 24/7 activity that requires active supervision of the region's bulk transmission system and reporting to the regulators on 'as required basis'. In the absence of a NBSO carrying out these reliability functions for the region, an alternative will be required.

Schedule 5 is a "Matrix of Regional Electricity System Operations Options" which summarizes and compares various system operations structures and characteristics, including implementation considerations.

Current System Planning

Planning in the Atlantic region, while subject to provincial public policy and regulatory oversight, is primarily within the control of the individual utilities, except in New Brunswick where NBSO has the legal responsibility as resource planner and reliability planning coordinator. As a member of NERC and interconnected to the US system, the Maritime region must also meet the reliability standards of NERC as laid out in its Reliability Functional Model. The Model's three main planning areas are Planning Reliability, Resource Planning, and Transmission Planning:

- Planning Reliability Coordinator – the functional entity that coordinates, facilitates, integrates and evaluates (generally one year and beyond) transmission facility and service plans, resource plans within a Planning Coordinator area and coordinates those plans with adjoining Planning Coordination areas.
- Resource Planner- the functional entity that develops a long term (generally one year and beyond) plan for the resource adequacy of specific loads (customer demand and energy requirements) within a resource planning area.
- Transmission Planner – the functional entity that develops a long term (generally one year and beyond) plan for the reliability (adequacy) of the interconnected bulk electric transmission systems within a Transmission Planner area.

ISO-NE undertakes all of these functions as part of its mandate. Significant coordination among the Atlantic utilities now occurs, with management of confidential economic data being a priority. The planning function is a key ingredient of the FERC and NERC regulatory planning functions, with significant effort being placed on creating a standard that strengthens interconnection compatibility.

Recently FERC released Order 1000 which is a Final Rule addressing electric transmission planning and cost allocation requirements for public utility transmission providers. This Order builds on the reforms of Order 888 by Order No. 890 and corrects what it states are remaining deficiencies with respect to transmission planning processes and cost allocation methods.

The impacts of Order 1000 on the planning and operating systems of Atlantic Canada are not known yet as each jurisdiction must determine where they fit, how they fit, and who they will have to work with on regional planning and with interconnecting regions. New Brunswick would be the most affected because of its multiple interconnections, especially with ISO-New England and N.ME.

FERC Order 1000 establishes three requirements for transmission planning:

1. Each public utility transmission provider must participate in a regional transmission planning process that satisfies the transmission planning principles of Order No. 890 and produces a regional transmission plan.
2. Local and regional transmission planning processes must consider transmission needs driven by public policy requirements as established by state or federal laws and regulations. Each public utility transmission provider must establish procedures to identify transmission needs driven by public policy requirements and evaluate proposed solutions to those transmission needs.

3. Public utility transmission providers in each pair of neighbouring transmission planning regions must coordinate to determine if there are more efficient or cost-effective solutions to their mutual transmission needs.

FERC Orders are significant as they not only establish the approaches being followed in the US electricity industry, but are also used to determine the standard of interconnection provincial jurisdictions must have with the US market. FERC Orders are mandatory on NERC who has authority in certain Canadian provinces, including New Brunswick and Quebec that have signed agreements or established laws empowering NERC authority; and Nova Scotia where the UARB and NERC have two MOUs that include NERC, NPCC, and NSPI activities.

The impact of FERC Order 1000 is not known, but with the expanded emphasis on regional transmission plans and the role of public policy, its objective clearly seems to be to regulate on the basis of greater regional cooperation and cost effective solutions. Atlantic Canada's electricity systems, with its interconnections to five eastern provinces and New England, will have to take into consideration this new FERC Order and regulatory approach, especially as increased renewable energy sources and the planned interconnections of Labrador and the Island of Newfoundland are achieved in the next decade.

4. Regional System Operations Issues and Implementation Considerations

An objective of increased regional cooperation in the electricity sector is to create efficiencies and cost benefits to consumers and industry and broader economic benefits for the region and the rest of Canada.

Atlantic Canada is a relatively small electricity marketplace with approximately 8900MW of generating capacity, not counting the Upper Churchill Falls output of 5428MW, which is mostly exported to Quebec. Peak demand for the region in 2010 was approximately 6700MW or 75% of capacity. Current Atlantic regional capacity compares with approximately 42,000MW in Quebec, 40,000MW in Ontario, and 38,000MW in New England. However, even a relatively small Atlantic regional system is quite complex, spread over a large and often rural geography with broad differences in social and economic circumstances and also in environmental and clean energy policies and targets.

The regional electricity landscape and the North America world of electricity has changed significantly since 2007. The global economic downturn has resulted in an absolute drop in electricity consumption in most North America markets rendering previous growth forecasts obsolete and creating over capacity in many marketplaces. The optimism for exporting large amounts of clean renewable energy has dimmed in the near term, and the rapid growth of natural gas extracted by new technologies from shale has fundamentally changed the North America and global prices for gas for the foreseeable future, making natural gas the "power generation fuel of choice" in many markets.

These rapid industry-wide changes, together with some of the new proposed major regional projects such as Muskrat Falls and the energy and environmental policy changes in NB and NS, have created changing dynamics for the electricity sector in Atlantic Canada. Therefore, it can be argued that this same climate of change and uncertainty presents a compelling case for increased regional cooperation and improved economies though partnerships and integration that could produce efficiencies, benefits, and more stable future electric prices for customers.

The importance of open transmission access and preventing "market power" by any one or small group of utilities is at the center of any electricity transmission system that is interconnected to other jurisdictions, especially the US marketplace. These regulatory rules and standards will continue to grow in influence as the Atlantic region's system changes and expands.

Some of the regional electricity systems operations issues, factors, and planning considerations that governments and utilities may need to examine in the future are discussed below. The region currently has both an over capacity of conventional generation and large undeveloped wind, tidal and hydropower renewable energy potential. The future impact of individual provincial and regional collaboration actions on future sources of electrical energy and prices to consumers could result in region-wide changes. However, any changes that may be agreed to in the future are more likely to occur over time as various changes, adjustments, and collaborative actions are identified, assessed, and executed.

System Operator

An example of the changing landscape is the NB policy decision to combine most of the functions and responsibilities of the current independent system operator, NBSO, into its crown utility, NB Power. This will have a number of operating consequences for both the NB electricity administrative situation as it relates to generation and transmission in New Brunswick and also for its inter-relationships with other provinces and the Northeast USA. Any plan for transferring specific NBSO functions and responsibilities into NB Power will also need to take into account those responsibilities that still require an "independent" entity, such as regional reliability coordination.

Some of the regional systems operations activities that any new regional governance model or independent entity may be required to administer include: regional operating reserves, regional systems balancing, and regional systems reliability coordination and inter-facing with the Northeast USA. In order to carry out any or all of these functions, such an entity would require some degree of system-wide modeling and access to relevant multi-utility data.

While, in the short term, enhanced coordination may be the next stage in expanding regional electricity and clean renewable energy cooperation, in the longer term there may be merit in examining potential benefits and implementation considerations for an ISA or similar administrative and system operations concept, as well as the option of a common regional market and regional ISO such as exists in New England and Ontario. Any expanded regional cooperation would require negotiations to ensure that there are benefits to all jurisdictions.

Regulation

Another area that increased regional electricity cooperation and systems operations would impact is the nature of industry regulation in the provinces and regionally. The current regulatory organizations and legislative regimes of the four Atlantic Provinces have many similarities, but also many differences in mandates and professional resources. However, in the electricity industry there are established standards of reliability, safety, cost-of-service principles, rate setting, and other key factors. None of these variances are insurmountable. To achieve greater regional collaboration and efficiencies would require clear objectives and policies that are shared by all the major stakeholders. In some instances, it could also require coordination and alignment of provincial legislation.

USA Regulatory Interrelationships

Another major regulatory area that will require ongoing change, and in some cases expanded coordination and compliance, is the region's administrative relationship and role with the USA and specifically FERC and NERC.

Because Atlantic Canada is linked to the United States electricity transmission systems in a number of places such as New Brunswick directly and through Quebec, and Labrador through Quebec, there are a number of US regulatory policies and regulations that Canada's utilities must adhere to. For example, FERC's policy of non-discriminatory open access to transmission (OATT) is a mandatory policy for which any Canadian utility exporting to the US must meet FERC approval. As outlined previously in this Overview Paper, the rules and regulations regarding the operation and infrastructure necessary for the safe and reliable operation of the electricity generation transmission system are the responsibility of a number of organizations in the US that interact with Canada's electricity industry.

In addition to these US regulatory organizations, there is Canada's National Energy Board (NEB) and its regulatory role with respect to cross-border transmission of electricity of all Canadian utilities.

Regional Planning

Currently each regional government, regulator, and respective utilities conducts its own planning functions, analyzes, and approval processes for each of the four provincial electricity systems. The opportunity for increased regional planning may be opportune because of the short term regional electricity forecast indicating over capacity and the competitive situation for exporting electricity is more challenging due to Quebec's surplus capacity and New England's power supply, demand, and pricing situation,

Four of the major planning functions and approaches that could be part of any future cooperation considerations include:

- The role of government as developers of public policy.
- The potential for increased efficiency from broader area planning versus commercial confidentiality of individual utilities.
- Reliability standards and their application to small provincial transmission systems.

- Resource planning requirements that integrate renewable targets as set by individual provinces.

The regional electricity capacity situation will continue to change with the return to production of the Lepreau nuclear plant in 2012, the development and in-service of Muskrat Falls hydropower by 2017, and the expected addition of clean renewable energy projects. In the longer term, there are several other potential major electricity projects that could be developed in Atlantic Canada for domestic use and/or export including: 2200MW Gull Island hydropower project in Labrador; a 2nd nuclear plant in NB; large scale tidal power in NS and NB on the Bay of Fundy; additional natural gas from NS, NB, and offshore Newfoundland and Labrador; and large wind projects in PEI and elsewhere in the Atlantic Provinces.

Implementation Opportunities, Challenges, and Constraints

As previously outlined in this Overview Paper, there are many factors and forces impacting the electricity and clean renewable energy jurisdictions of the four Atlantic Provinces. The relatively small size of the regional marketplace, combined with the continuing upward pressures on power rates to all consumers, increases the need for policy makers and utilities to seek opportunities to improve operating and transmission efficiencies and create reduced costs, and to expand the development of new renewable energy resources. Existing surplus capacity and future new power developments can create economic opportunities for local economic growth and for sales to export markets.

Pursuing future regional cooperation and growth opportunities will face a number of challenges and structural constraints. It will require closer provincial policy and regulatory interaction by all of the participants. This will lead to more openness in sharing information, conducting joint analyses, and negotiating with a longer-term perspective versus a short-term “must gain” approach.

Such a regional approach to increased cooperation and integration of some of the activities of the electricity and clean renewable energy sectors could signal the beginning of developing a truly “Atlantic Canada regional power market”.

Some of the factors, policies, and structural constraints that would need to be addressed are identified and briefly described below:

a. Both the proposed addition of a third sub-sea cable between PEI and NB strengthening the NB/NS interconnection, and the Muskrat Falls hydropower project’s sub-sea linkage from the Island of Newfoundland to NS will involve new high-voltage transmission lines. This is an opportunity for increased regional cooperation and for improvements to transmission capacity and reliability among the four Atlantic Provinces, and for higher export capacity to the New England market and Canadian provinces west of Quebec.

b. The goal of increasing clean renewable energy sources from PEI, NS, and NB will require additional transmission capacity and inter-ties because the total wind capacity of 774MW that is currently in-place in the three Maritime Provinces is stretching the regional system's ability to deliver this intermittent power to acceptable reliability standards. This opens up the opportunity to cooperate on integrating wind and other renewable power on a region-wide basis, thereby assisting each province and its utilities to meet the policy goals that have been set, while also pursuing new economic development potential.

c. Regional cooperation to build increased transmission capacity and to develop additional renewable energy sources such as wind demonstrates the need for some form of expanded regional regulatory coordination and governance of interprovincial power transactions. Such regulatory coordination has already been occurring on certain system reliability actions and standards in compliance with NPCC rules.

d. Developing a regional power market approach with a goal of delivering the lowest-cost and reliable power, while achieving the various clean and non-emitting energy policies and targets, will highlight the need to cooperatively assess the most economic use of various existing and future generation and transmission assets. A more efficient integrated system should lower electricity costs to all consumers.

e. A regional approach will require examination of systems operations factors such as:

   - the current transmission tariff structures and the manner in which each individual system operates its OATT;
   - the operating procedures for existing balancing and reserve capacities and whether there are savings to be achieved from integrated operations by reducing the amount of reserve capacity currently being tied up by individual systems; and
   - in light of the proposed roll-up into NB Power of the region's only independent system operator, NBSO, how will the critically important managing the operation of the transmission system to region-wide reliability standards, operational balancing requirements, and to some degree of regional resource planning be achieved?

f. Increasing regional cooperation and coordination for the electricity sector and related environmental and renewable energy policies will require an examination of existing provincial electricity, renewable energy, and regulatory legislation. Such an examination will likely result in some increase in the harmonization of such policies, regulations, and legislation.

Concluding Comments

There are opportunities for the four Atlantic Provinces to increase cooperation and coordination of their electricity sectors and to start on a path to create an Atlantic Canada power market. This course of action will be a strong signal that the region intends to improve its competitiveness for economic development, to actively pursue export markets for its power, and to achieve the lowest-cost power possible for its residential and business consumers. This road will require cooperative action and will not be without its challenges as the various opportunities are identified, assessed, and implemented in a mutually acceptable manner.

Schedule 1: Atlantic Region Electricity Regulatory Systems

Each of the four Atlantic Provinces has a regulator for its electricity sector that in some cases also regulates a number of other utility-type functions. In addition, the NEB is the federal regulator and has certain functions in the interprovincial and international transmission and sale of electricity.

Newfoundland and Labrador

The PUB is an independent, quasi-judicial regulatory body appointed by the Lieutenant Governor in Council, and operates primarily under the authority of the Public Utilities Act, R.S.N. 1990. The Board was established in 1949.

The PUB is responsible for the regulation of the electric utilities in the province to ensure that the rates charged are just and reasonable, and that the service provided is safe and reliable. The PUB is responsible for the general supervision of NLH and NP, and for the electricity rates, borrowing programs, and capital programs. The basis of electricity regulation is on a cost of service methodology whereby both NLH and NP are entitled to recover through customer rates all reasonable costs incurred in providing electricity service to their customers, plus a return on rate base.

The PUB has approved a 2011 rate of return range on rate base for NP of 7.78-8.14%, and NLH has received Government approval to seek a similar rate of return range in its next general rate application.

Nova Scotia

The UARB is an independent quasi-judicial body which has both regulatory and adjudicative jurisdiction flowing from the NS Utility and Review Board Act. It was established in 1992 and has evolved to be a very diverse regulatory and supervisory organization with a Chair and nine commissioners. It is responsible to the NS Legislature through the Minister of Finance for the all public utilities including NSPI. Its jurisdiction with respect to NSPI includes setting rates, tolls and charges; regulations for provision of service; approval of capital expenditures in excess of $250,000, and any other matter the UARB feels is necessary to properly exercise its mandate.

The UARB rate-making methodology is based on a cost of service model whereby rates are to reflect the cost to the utility of providing electric services to each distinct customer class so as to generate total revenue requirements to the utility that include a fair return. A principle of this rate-making model is to achieve price stability from year-to-year as much as possible. One recently introduced new and important component to this model, effective January 2009, is a "fuel adjustment mechanism" ("FAM") formula whereby NSPI is entitled to seek annual adjustments, either up or down, to its rates because of changes in its costs of fuel for generation. The first FAM was approved in August 2010.

NSPI has to periodically provide a comprehensive Cost of Service Study to the UARB and its stakeholders, and also to prepare a long-term Integrated Resource Plan ("ISP") which is a forecast of all of its operating and financial components and their projected impacts on the utility's revenue requirements. Under all significant assumptions, NSPI is in the late stages of regulatory and stakeholder consultations for a new IRP.

The provincial energy efficiency corporation, Efficiency Nova Scotia, had its first UARB public hearing in 2011 and in a Board Decision on June 30, 2011, the Board approved a ratepayer funded Demand Side Management program for 2012 totalling $43.7 million, which will be included in future electricity rates.

New Brunswick

The New Brunswick EUB is an independent crown agency established by the Legislature to regulate the electricity, natural gas, motor carrier industries and set maximum gasoline prices for the province.

The EUB was established in 2007 by the New Brunswick legislature with the implementation of the Energy and Utilities Board Act. The EUB is the successor to the Public Utilities Board that had operated in New Brunswick since the 1920's. The Board's duties are carried out by a staff of 16 including a full-time chair and vice-chair. There are up to eight part-time Board members who are called upon as needed to participate in hearings. The Board members are appointed by the Lieutenant Governor in-Council.

The role of the EUB is to act as an independent, quasi-judicial agency to oversee aspects of the energy sector and to regulate the charges passed on to customers by the province's various utilities, including NB Power. The EUB is required to balance consumer rights to reasonable prices with the company's right to a fair return on its investment.

The EUB has a variety of responsibilities in relation to the electricity market in NB. In terms of NB Power, only the Distribution and Customer Service, the subsidiary that delivers electricity to the homes of most New Brunswick residential customers, is under the jurisdiction of the EUB for any changes in rates in excess of three percent. The EUB also reviews and approves an annual revenue requirement for the system operator NBSO that covers the cost of operating the transmission system, including the costs associated with the transmission subsidiary company of NB Power. Generation facilities are not the responsibility of the EUB because under the NB electricity industry restructuring in the early 2000s, it was expected that a competitive market would develop and result in open bidding for electricity supply. This has not occurred.

Prince Edward Island

The IRAC is an independent tribunal that hears appeals on issues relating to a wide range of public policy areas such as land use and certain water and wastewater utilities. It is also responsible for the regulation of electric utilities.

The IRAC was established in 1991 following the amalgamation of the former Public Utilities Commission, Land Use Commission, and the Office of the Director of Residential Rental Property (Rentalsman).

The IRAC operates at arm's-length from the Provincial Government. It has three full-time and up to five part-time Commissioners and a staff complement of 18. It reports to the Legislative Assembly of PEI through the Minister of Education.

National Energy Board

The NEB is an independent federal agency established in 1959 by the Parliament of Canada to regulate international and inter-provincial aspects of the oil, gas and electric utility industries. The purpose of the NEB is to promote safety and security, environmental protection, and efficient energy infrastructure and markets in the Canadian public interest, within the mandate set by Parliament in the regulation of pipelines, energy development and trade. The NEB is accountable to Parliament through the Minister of Natural Resources Canada.

Most electric power lines and facilities fall within provincial jurisdiction. The NEB authorizes the construction and operation of international power lines and designated inter-provincial lines under federal jurisdiction. In determining the suitability of an application, the NEB reviews, among other things, the technical feasibility of the project, its effect on adjacent provinces, and its environmental impact. Almost all Canadian provinces bordering the U.S. have interconnections with neighboring American utilities.

Typically, permits are issued to export electricity without a public hearing unless the Governor in Council, after recommendation by the NEB, designates a particular application for licensing or certification. The NEB does not regulate electricity imports. Issues that the NEB considers when making its decisions may include the effect of exports on adjacent provinces, the environment, and fair market access for Canadians.

SCHEDULE 2: REGIONAL ENVIRONMENTAL AND RENEWABLE POLICIES, RULES, AND TARGETS

The Atlantic Provinces electricity industry, like other electricity sectors in Canada, North America, and in many parts of the world, have undergone a significant shift in public policy and regulation in recent years as it relates to cleaner sources of energy and reduced impacts on air emissions.

The Atlantic region's electricity industry has a variety of Greenhouse Gas ("GHG") policies, both provincial and federal, and also a variety of renewable energy portfolio goals or targets, some set in legislation.

Provincial Policies and Air Emission Targets

Nova Scotia

NSPI is required to operate under the Nova Scotia Public Utilities Act and must comply with the NS Renewable Electricity Regulations and the NS Air Emissions Act that include the only hard caps for CO2 emissions in Canada. Specifically, the NS requirements cover and mandate that a portion of electricity is to come from NS sources; state air quality requirements with respect to NS facilities, and state hard caps on GHG's.

The major environmental and clean renewable energy policies that apply to NSPI are:

- 25% Renewable Electricity by 2015- The NS plan commits the 2015 target of 25% renewable electricity to law.
- 40% Renewable Electricity by 2020- By 2020, this goal means more than 500,000 homes will be running on renewable power, more than enough energy for every residential customer in Nova Scotia. This has recently been put into law, and draft regulations are receiving public comment.
- Community Projects- This plan establishes a community-based feed-in tariff for municipalities, First Nations, co-operatives and non-profit groups.
- Renewable Energy Competition- Half of all large and medium-scale renewable energy projects will be set aside for Independent Power Producers, with bidding to take place under a competitive system. All bid processes will be managed by a new authority, the Renewable Electricity Administrator. NSPI will be responsible for the other half, with projects evaluated and approved by the UARB.

The GHG targets are contained in the NS Environmental Goals and Sustainable Prosperity Act ("EGSPA") established in 2007. This Act set targets for the following GHGs: carbon dioxide, methane, nitrous oxide, hydrofluorocarbons, perfluorocarbons, and sulphur hexafluoride These GHGs and Mercury targets will have a significant impact on the power generation and operations of NSP because they are 'hard caps' that must be met by reducing or "scrubbing" fossil fuels such as coal and oil, and/or replacing them with clean energy sources. The overriding target of the EGSPA is that by 2020 Nova Scotia will have 10% less greenhouse gas emissions than 1990 levels.

New Brunswick

The NB Electricity Act also includes the electricity from Renewable Resources Regulations, which requires NB Power to procure 10% of its energy requirement from new renewable energy sources by 2016. There is no provision in the regulation that the energy be sourced in New Brunswick, although government policy to date has been to include this requirement in the requests for proposals for new wind capacity.

NB introduced its Climate Change Action Plan in 2007 that established a target for reducing GHGs to 1990 levels by 2012, and by 10% below 1990's level by 2020. In addition, a long-term goal of a total reduction of 65% by 2050 was set. These GHG goals are broken down by sectors and summarize what each sector is expected to contribute to achieving these GHG reduction goals. In addition, the provincial government provided funding to the NB Energy Efficiency and Conservation Agency ("Efficiency NB") to develop and implement Demand Side Management programs to assist in achieving these environmental and air emission policies and goals.

Prince Edward Island

PEI has a Renewable Energy Act that was introduced in March 2011 and operates together with the provincial Electric Power Act. PEI's original Renewable Portfolio Standard ("RPS") was introduced in 2003 and set a target that 10% of energy used would come from renewable energy sources by 2010. Wind power was expected to account for most of that 10%, or about 35-40MW of capacity. A later RPS set a target for renewable energy of 15% by January 1, 2010; however, this target was reached in 2007.

PEI has a diverse portfolio of renewable energy sources that include wind power, solar, biomass, biogas, and biofuels, geothermal, and a wind/hydrogen demonstration project. The Province also has an energy efficiency and conservation program delivered through the Office of Energy Efficiency that was established in 2008.

PEI's 2008 Climate Change Strategy established a goal of reducing 2001 levels of GHGs by 75-85% by 2050, and also committed to reducing carbon dioxide ("CO2") levels per megawatt of electricity by 20% by 2020. The core programs to achieve the Province's climate change goals are adaption and public education and awareness. While the electricity sector only generates 30% of PEI's air emissions, compared to an average of 56% nationally, the sector will achieve its reduction goals by a significant increase in wind power generation.

Newfoundland and Labrador

NL generates approximately 85% of its electricity from clean renewable hydropower and a small amount (51MW) from wind. As a result, only 12% of the total provincial per capita GHGs come from the electricity sector. However, the annual percentages can be as high as 35% on the Island because of the 490MW oil-fired (Bunker C) thermal plant at Holyrood, 30 miles outside of St. John's, which accounts for 1.3 million tonnes of GHGs and other pollutants annually. The proposed 824MW hydro plant on the Lower Churchill River in Labrador will increase the Island to almost 100% clean renewable energy and also contribute annual reductions of approximately 5 million tonnes of GHGs, equivalent to an estimated 900,000 car emissions.

The development of Muskrat Falls will also permit an increase in wind power generation over the current system's constrained limit of 80MW, because the system will be able to "balance and integrate" larger amounts of wind due to water storage capabilities and the new transmission interconnection with Labrador and expanded Island transmission.

NL has an Office of Climate Change, Energy Efficiency, and Emission Trading, and introduced a new Climate Change Action Plan in August 2011. The Plan reaffirmed the provincial goal on GHGs to achieve a 10% reduction over 1990 levels by 2020, and an overall reduction of 75-85% reduction by 2050. In addition, NL has policies in place that will reduce sulphur dioxide (SO2) levels by 50% and particulate pollutants by 40%. Currently NL's per capita GHGs are 15% lower than the national average. The existing 51MW of wind power have reduced NL's GHGs by 15%.

The Climate Change Action Plan has a number of industry-wide and societal goals and programs to achieve a broad improvement in environmental and air emission standards. The government's initial funding for energy efficiency was $5 million, and it is committed to increased investment. An important element of this Plan is a short- and long-term commitment to adaption, education and awareness programs in all sectors of the economy and for individuals.

Federal Government Coal Regulations

In August 2011, the federal government published proposed regulations for coal-fired electricity generation units. Quoting from the federal Release: "The proposed '*Reduction of Carbon Dioxide Emissions from Coal-Fired Generation of Electricity Regulations*' will set a stringent performance standard for new coal-fired units and for those that have reached the end of their useful life. This will phase out high-emitting coal-fired generation and promote a transition towards lower or non-emitting types of generation such as high-efficiency natural gas, renewable energy, or fossil fuel-fired power with carbon capture and storage.” The regulations set individual retirement dates for Canada’s 21 coal plants.**

The central action in the proposed regulations is to limit each unit's emissions to 375 tonnes of carbon dioxide for each gigawatt-hour (GWh) of electricity produced from all fossil fuel sources in a calendar year. These regulations would apply only to coal-fired units commissioned after July 1, 2015, and to those that have reached the end of their useful lives. In most cases, a unit has reached the end of its useful life on the later of 45 years from its commissioning, or 2020.

The federal government stated that its approach to addressing climate change is based on the principle of balancing environmental and economic considerations while recognizing the electricity industry requires significant capital expenditures and that regulatory uncertainty could impede investments in new generation capacity.

NB has one coal-fired plant, while NS has three coal generation plants that, together with petroleum-coke, produce approximately 75% of its annual energy.

The proposed regulations were open for comment until October 26, 2011. Final regulations are expected to be published in 2012 and come into effect on July 1, 2015.

* The Federal Government and some of the provinces and utilities have been holding discussions to find alternate methods of achieving these environmental and emission goals.

SCHEDULE 3: SUMMARY OF NOVA SCOTIA ELECTRICITY REGULATORY RELATIONSHIPS, AUTHORITIES, AND RESPONSIBILITIES IN THE MARITIME PROVINCES AND NORTHEAST USA (*)

Introduction

The electricity system transmission grid is connected throughout all jurisdictions in North America including cross-border interconnections between Canada and the United States. Due to the nature of electricity, transmission and generation operational outage occurrences in one jurisdiction may have a significant impact on the operation of connected jurisdictions. This was clearly evident in 2003 when a major substation outage occurred in Ohio resulting in a cascading effect throughout the Northeastern region of the United States and Canada. The Maritime region was fortunate during that major outage only because the system operator for the region (New Brunswick System Operator) was able to disconnect from the Northeast before the Maritime region was affected.

The rules and regulations regarding the operation and infrastructure necessary for the safe and reliable operation of the electricity generation transmission system are the responsibility of a number of organizations. These organizations include the United States Federal Energy Regulatory Commission (FERC), the North American Electric Reliability Corporation (NERC), the Electric Reliability Organization (ERO), the Northeast Power Coordinating Council (NPCC), the National Energy Board (NEB), the Competition Bureau (Canada), and in the Maritimes, the New Brunswick System Operator, the Nova Scotia Power System Operator, and the Nova Scotia Utility and Review Board (UARB). Each of these organizations has a role and responsibility regarding the safe and reliable operation of the generation and transmission system.

Federal Energy Regulatory Commission (FERC)[2]

The US Department of Energy Organization Act established the US Federal Energy Regulatory Commission (FERC) in 1977. FERC has no direct authority in Canada. FERC is an independent agency that regulates, and has jurisdiction over, interstate electricity sales, wholesale electric rates,

*-Source-Memo for AEG by Richard Penney, Nova Scotia Department of Energy,2010

[2] http://www.ferc.gov/about/about.asp

hydroelectric licensing, natural gas pricing, and oil pipeline rates. FERC also reviews and authorizes liquefied natural gas (LNG) terminals, interstate natural gas pipelines and non-federal hydropower projects. In 2005 the Energy Policy Act gave FERC additional responsibilities. Those additional responsibilities relating to the electricity sector include:

- The review of mergers and acquisitions and corporate transactions by electricity companies.
- The review of siting applications for electric transmission projects.
- Protecting the reliability of the high voltage interstate transmission system through mandatory standards.
- Monitoring and investigations of energy markets.
- Oversight for environmental issues relating to electricity projects.
- The ability to enforce FERC regulatory requirements through civil penalties.

Figure 1

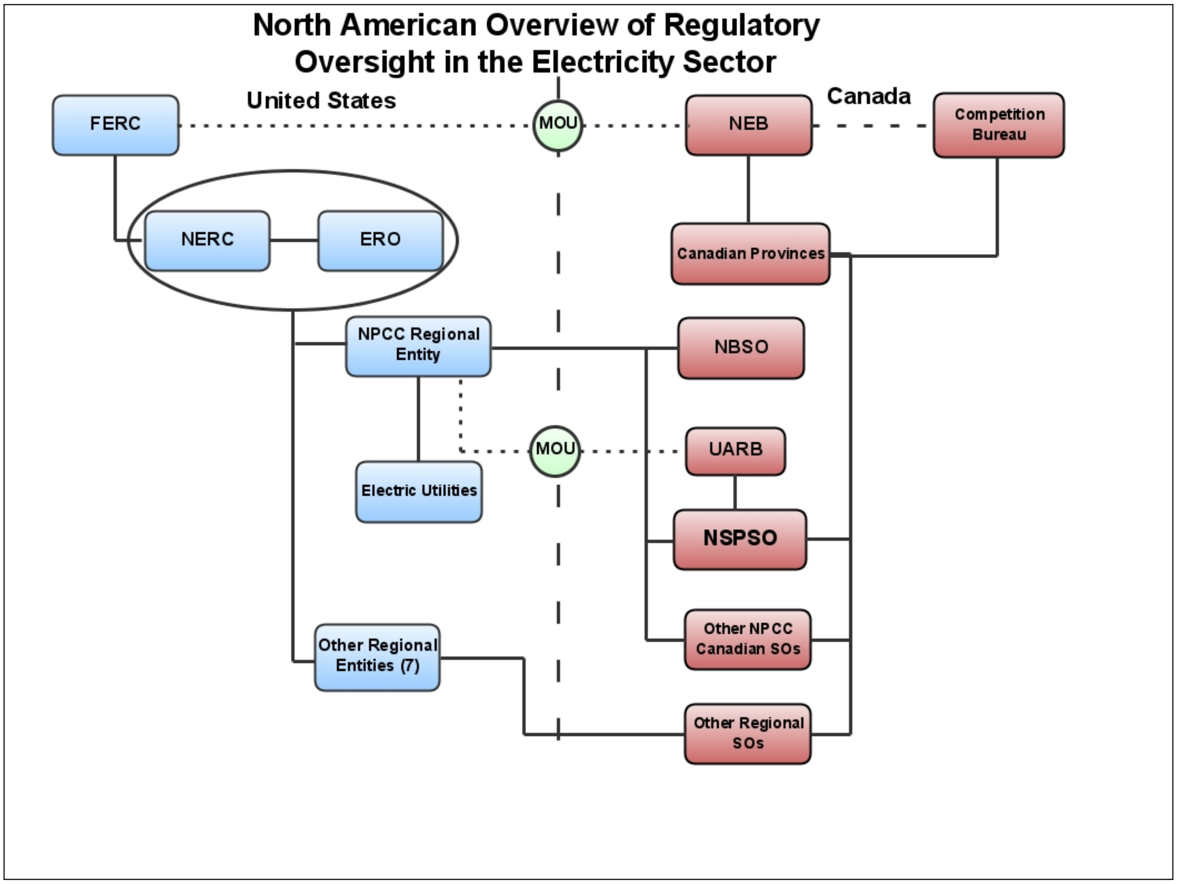

Figure 1 shows a high level North American overview of regulatory oversight for the electricity sector.

FERC's mission is to assist consumers in obtaining reliable, efficient and sustainable energy services at a reasonable cost through appropriate regulatory and market means. FERC is the umbrella under which most other energy organizations operate, and its mission involves two primary goals:

- Ensure that energy rates, terms, and conditions are just, reasonable, and not unduly discriminatory or preferential
- Promote the development of safe, reliable, and efficient energy infrastructure that serves the public interest.

AEG Report on Regional Electricity System Operations – March 30, 2012

In September 2003, a trilateral agreement was signed between the NEB, the Comision Reguladora de Energia , (CRE, Mexico) and FERC in which the three agencies agreed to regularly share perspectives on regulatory approaches and to work on eliminating inconsistencies in regulation to the extent possible. The NEB, CRE and FERC have been meeting three times a year to pursue these objectives.

It was at the trilateral meeting in May 2004 that the NEB and FERC signed a Memorandum of Understanding (MOU) to enhance inter-agency coordination. This agreement reinforces the existing cooperative relationship and further commits each agency to work together to the extent possible within our respective legal mandates to harmonize our regulatory approaches to cross-border projects.

From time to time, when there is a demand for regulatory guidance relating to the electricity industry issues, FERC establishes regulations and orders to address the situation. Orders 888 and 889 are of particular interest to the industry because they address the promotion of wholesale market competition through open access non-discriminatory transmission tariffs and services (OATT), standards of conduct, and open access same-time information systems (OASIS).

North American Electric Reliability Corporation (NERC)[3]

The NERC is a non-profit corporation with a responsibility to ensure the reliability of the bulk power system in North America. NERC operates under the rules and regulations established by FERC, and in 2008 FERC certified NERC as the *Electric Reliability Organization*[4] (ERO), a self-regulating reliability organization with the authority to establish and enforce reliability standards for the bulk power system in North America

The investigation report into the 2003 North American Eastern Seaboard blackout recommended that mandatory and enforceable reliability standards were the key to improving the reliability of the North American bulk power system. In 2006, NERC filed the first set of enforceable standards with FERC and FERC approved 83 of the 102 proposed standards.

NERC has no authority in Canada. However, NERC currently has signed memorandums of understanding (MOU) with provincial authorities in New Brunswick, Quebec, Ontario, Saskatchewan, and the Canadian National Energy Board (NEB). Both Ontario and New Brunswick have established provincial law that makes NERC standards mandatory and enforceable within their jurisdiction. Manitoba and NERC have a signed agreement that reliability standards mandatory for Manitoba Hydro, and Manitoba has recently adopted legislation setting out a framework for

[3] http://www.nerc.com/

[4] http://www.nerc.com/files/NERC_Rules_of_Procedure_EFFECTIVE_20080321.pdf

reliability standards to become mandatory for all electricity users, owners, providers and operators in Manitoba. Under Alberta's Transportation Regulation, NERC is designated as the ERO in that province. Alberta has approved a number of NERC's reliability standards and a number are pending approval. In Quebec, the Regie de l'energie of Quebec has recognized NERC and the Northeast Power Coordinating Council (NPCC) as standards-setting organizations. Quebec has also put the necessary legislative framework in place to make reliability standards mandatory within Quebec's jurisdiction.

British Columbia and Nova Scotia are also developing the necessary framework to make NERC's and NPCC's reliability standards mandatory and enforceable. In Nova Scotia, NERC and NPCC are working with the Nova Scotia Utility and Review Board (UARB) to adopt reliability standards, although the Nova Scotia Power System Operator (NSSO) has adopted and maintains compliance with the NERC standards. NERC is working with the remaining Canadian governmental authorities to establish equivalent recognition.

Northeast Power Coordinating Council (NPCC)[5]

NPCC is one of 8 regional entities under the NERC umbrella. NPCC is a not-for-profit corporation in the state of New York. It is responsible for promoting and improving the reliability of the international, interconnected bulk power systems in the northeastern region of North America. Responsibilities include:

- Development of regional reliability standards
- Reliability standards compliance assessment
- Enforcement of continent-wide and regional reliability standards
- Coordination of system planning, design and operations
- Assessment of regional reliability
- Establishment of regional specific reliability criteria
- Monitoring and enforcement of compliance with reliability criteria

NPCC provides its member jurisdictions with the functions and services of a cross-border regional entity through a regional entity division, along with regionally specific criteria services through a criteria services division.

The NPCC region covers nearly 1.2 million square miles, populated with more than 55 million people. The NPCC region includes the state of New York and all six New England states in the US, and the provinces of Quebec, Ontario, New Brunswick and Nova Scotia. Prince Edward Island is represented by New Brunswick and is part of the Maritime area. From a net energy for load

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[5] http://www.npcc.org/

perspective, NPCC is 45% US and 55% Canadian. The NPCC Canada region represents nearly 70% of the net energy-for-load in all of Canada.

Although Nova Scotia's electric utility, Nova Scotia Power, is a member of NPCC, it does not have any direct international cross-border interconnection with the US. Nova Scotia is interconnected to the US via New Brunswick and the New Brunswick System Operator.

National Energy Board (NEB)[6]

The NEB is an independent federal agency established in 1959 by the Parliament of Canada to regulate international and inter-provincial aspects of the oil, gas and electric utility industries. The purpose of the NEB is to promote safety and security, environmental protection and efficient energy infrastructure and markets in the Canadian public interest within the mandate set by Parliament in the regulation of pipelines, energy development and trade. The NEB is accountable to Parliament through the Minister of Natural Resources Canada.

Most electric power lines and facilities fall within provincial jurisdiction. The Board authorizes the construction and operation of international power lines and designated inter-provincial lines under federal jurisdiction. In determining the suitability of an application, the NEB reviews, among other things, the technical feasibility of the project, its effect on adjacent provinces, and its environmental impact. Almost all Canadian provinces bordering the U.S. have interconnections with neighboring American utilities.

Typically, permits are issued to export electricity without a public hearing unless the Governor in Council, after recommendation by the NEB, designates a particular application for licensing or certification. The NEB does not regulate electricity imports. Issues that the NEB considers when making its decisions may include the effect of exports on adjacent provinces, the environment, and fair market access for Canadians.

The amount of electricity exported is influenced by several factors. First, the amount exported cannot exceed the limits set by the NEB. Secondly, the weather plays an important role because approximately 70 per cent of exports are generated by hydro-electric facilities; low water levels in Canada reduce the amount of power generated and the amount available for export. Strong domestic demand can also reduce quantities available for export. Finally, the economics of export transactions influence the amount sold.

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[6] http://www.neb.gc.ca/clf-nsi/rcmmn/hm-eng.html

The NEB, when required, conducts studies or research into energy matters to meet its regulatory responsibilities. The NEB may also hold inquiries on its own initiative, when appropriate. With this knowledge and expertise, the NEB reports to and advises the Minister of Natural Resources on energy issues

Competition Bureau (CB)[7]

The Competition Bureau is an independent law enforcement agency that contributes to the prosperity of Canadians by protecting and promoting competitive markets and enabling informed consumer choice in Canada. The Competition Bureau is responsible for the administration and enforcement of the Competition Act (among other acts) that is a federal law governing most business conduct in Canada. The Act contains both criminal and civil provisions aimed at preventing anti-competitive practices in the marketplace. Its purpose is to maintain and encourage competition in Canada in order to:

- Promote the efficiency and adaptability of the Canadian economy
- Expand opportunities for Canadian participation in world markets while at the same time recognizing the role of foreign competition in Canada
- Ensure that small and medium-sized enterprises have an equitable opportunity to participate in the Canadian economy
- Provide consumers with competitive prices and product choices.

The Competition Bureau's primary operating principles are confidentiality, fairness, predictability, timeliness and transparency.

New Brunswick System Operator (NBSO)[8]

The NBSO is a not-for-profit independent corporation with the responsibility to ensure the reliability of the bulk power system and to facilitate the continued development and safe and reliable operation of a competitive electricity market in New Brunswick. The NBSO is one of 17 Reliability Coordinators in North America and is designated as the Reliability Coordinator for the Maritime area. The NBSO is the authority responsible for the operation of the bulk power in New Brunswick, Nova Scotia, Prince Edward Island and a small portion of Northern Maine.

The NBSO is also the Balancing Authority for New Brunswick, Prince Edward Island and Northern Maine. The NBSO provides load following and regulation service to the electrical system in order

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[7] http://competitionbureau.gc.ca/eic/site/cb-bc.nsf/eng/home

[8] http://www.nbso.ca/Public/en/docs-EN/NBSO%20Annual%20Report%202007-2008%20(en).pdf

to provide in-province customer load, while maintaining scheduled flows on interconnections within the established limits set out in interconnection agreements with neighbouring system operators. Neighbouring system operators include Nova Scotia, New England and Quebec.

Nova Scotia Power System Operator (NSPSO)[9]

The NSPSO is owned and operated under the umbrella of Nova Scotia Power. The NSSO is considered to be functionally independent from all other Nova Scotia Power operations under a Standards of Conduct that was approved by the Nova Scotia Utility and Review Board (UARB). The NSSO is responsible for the safe, reliable and efficient operation of Nova Scotia's bulk power system.

Nova Scotia has more than 5,200 kilometers of bulk transmission lines and about 25,000 kilometers of distribution transmission lines that are operated by the NSPSO. Nova Scotia has one major 345 kv transmission interconnection with New Brunswick and the rest of North America. Nova Scotia's transmission system is part of the Maritime regional transmission area within the NPCC that is part of the NERC. NSPSO must maintain reliability compliance with the NPCC and NERC reliability standards.

The NSPSO operates by remaining functionally independent from NSPI's generation and marketing functions. Standards of Conduct and the organizational structure for the various functions help the NSPSO operate a reliable and safe system and provide non-discriminatory access to the transmission system and transmission system information, without advantage to any power producer, including NSPI.

NSPI's Control Centre Operations (NSPSO) is the Balancing Authority for NS; NBSO is the Reliability Coordinator for the Maritimes Region. The Interconnection Agreement (a confidential contract between NSPI and NBSO) establishes a framework for the following functions related to the Reliability of interconnected operations between the Parties:

- Establishing the NBSO as the Reliability Coordinator for the Maritimes Area
- Coordinating operation of the New Brunswick and NSPI Transmission Systems
- Developing and issuing Operating Instructions and Security Limits

[9] http://www.nspower.ca/

- Implementing the respective requirements of each of NERC and NPCC in respect to the operation of the NSPI Transmission System and the New Brunswick Transmission System
- Developing and adopting Operating Instructions
- Conducting operating performance reviews of the Interconnection Facilities
- Considering matters of transmission service priority and access
- Providing assistance in an Emergency and system restoration
- Developing procedures to notify adjacent areas of new or modified facilities and their expected impact on the interconnected transmission systems.

The Nova Scotia Power Open Access Transmission Tariff (OATT)[10] came into effect on November 1st, 2005. NSPI applied to the Nova Scotia Utility and Review Board for an OATT on May 12, 2004, and the tariff was approved on May 31, 2005. Subsequently, Market Rules were developed for the operation of the NS wholesale market. Government approved the Market Rules and issued regulations and the wholesale market officially opened on February 1, 2007.

Nova Scotia Power has contracted the New Brunswick System Operator (NBSO) to manage its Open Access Same-Time Information System (OASIS) reservation web site for transmission services. The OATT provides equal and fair opportunity to access the transmission system to all market participants. .Since the NSPI electrical system is integrated with the bulk power system across North America, NSPI is required to comply with standards and codes as governed by the NERC and the NPCC. This obligation to comply extends to market participants and generators interconnected with the Nova Scotia Power grid.

Nova Scotia Utility and Review Board (UARB)[11]

The Nova Scotia Utility and Review Board (UARB) is an independent quasi-judicial body which has both regulatory and adjudicative jurisdiction flowing from the Utility and Review Board Act. It reports to government through the Minister of Finance. The UARB was established on December 14, 1992 under the Utility and Review Board Act. The UARB exercises general supervision over all electric utilities operating as public utilities within the Province. This jurisdiction includes setting rates, tolls and charges; regulations for provision of service; approval of capital expenditures in

[10] http://oasis.nspower.ca/en/home/oasis/default.aspx

[11] http://www.nsuarb.ca/index.php?option=com_frontpage&Itemid=1

excess of $25,000 and any other matter the Board feels is necessary to properly exercise its mandate.

Nova Scotia Power Inc. (NSPI), an investor owned utility, is the largest public utility regulated by the UARB. NSPI is a fully-integrated public utility incorporated under the Nova Scotia Companies Act.

In 2004, the Nova Scotia Government passed the Electricity Act that, among other things, gave the Nova Scotia wholesale customers the right to purchase electricity from competitive suppliers. Nova Scotia Power Inc. (NSPI) was directed to apply to the UARB for an Open Access Transmission Tariff (OATT).

Under the Market Rules, the role of Market Monitoring is assigned to the UARB. The Nova Scotia System Operator provides the UARB with a report on the past year's activities. Parties can also appeal to the UARB for resolution of items covered under the Market Rules.

The government Regulations includes:

- *Marketing monitoring* – The market rules must provide for collecting, maintaining, reporting on and analyzing information and data required for the operation of the market.
- *Market surveillance* – NSPSO must provide the Board with the information and data that the UARB requests for market surveillance and for any investigation directed by the UARB.

In November, 2009, NSPI and NPCC met to draft an MOU to implement NERC standards with a target of submitting the agreement to the NSUARB in the next few months. NSPI are actively reviewing all the NERC standards to ensure compliance. NSPI has undergone several compliance audits from NPCC

SCHEDULE 4: PROFILES OF ATLANTIC, QUEBEC, AND NORTHEAST USA REGIONAL SYSTEM OPERATIONS

New Brunswick

NB established the Electricity Act (2004) which created a transmission operating system based on an independent system operator, NBSO, as a not-for-profit independent corporation whose primary responsibilities are to ensure the reliability of the electrical system and to facilitate the development and operation of a competitive electricity market in New Brunswick. NBSO ensures transmission system reliability; access to and use of the transmission grid (the high voltage wires); and administers the Open Access Transmission Tariff (OATT), the Market Rules, and also the "Open Access Same Time Information System ("OASIS") which is a secure, web-based interface to each transmission system's market offerings and transmission availability announcements. NBSO makes its OSASIS system available to NSPI, NSPSO and other market participants.

NBSO is also the Balancing Authority for NB, PEI and Northern Maine ("N.ME"), and has responsibilities for integrating resource plans, maintaining generation-load interchange balance, and conducting interconnection frequency in real-time.

NBSO is the Reliability Coordinator for NB, NS, PEI, and N.ME, and has responsibilities for maintaining the real-time operating reliability of the bulk electrical system within the reliability coordination footprint.

Nova Scotia

Nova Scotia's major utility, NSPI, has a "functionally unbundled" system operations entity, Nova Scotia Power System Operator ("NSPSO") which is a non-legal entity but with a clearly defined set of independent responsibilities and staff resources that provide the Wholesale Electric Transmission Services within Nova Scotia, and certain other functions and services to Independent Power Producers and Municipal Utilities. NSPSO's functions are administered using a FERC compliant Standards of Conduct. This specific code of conduct was established to govern NSPI's relationships with its transmission customers and potential customers, including the behaviour of employees of Nova Scotia Power and its Affiliates. These Standards of Conduct are based on FERC Order 2004 and earlier Orders 889 and Order 888 regarding non-discriminatory transmission open access, i.e. OATT.

Prince Edward Island

PEI has an operating system for the provision of transmission service based within Maritime using a Standard of Conduct similar to the approach followed in Nova Scotia. The Standard of

Conduct allows for the servicing of the independent municipal utility of Summerside and independent wind power generators.

Northern Maine

N. ME. is overseen by the Northern Maine Independent Administrator Inc. (NMISA), which is a non-profit entity responsible for the administration of N.ME's transmission system and electric power markets in Aroostook and Washington counties. This system has a load of approximately 130 MW. The NMISA is responsible for providing an independent, objective and non-discriminatory administration of all transmission access, transmission information access, and related functions. It also monitors and operates the markets in Northern Maine for energy, ancillary, and other services. NMISA administers the transmission systems of the investor-owned and cooperatively-owned utilities in N. ME. Its members include all municipally-owned utilities, generators, suppliers of energy, and large retail customers operating in the service area. Individual utilities continue to operate their section of the transmission system, subject to established agreements with the NMISA. NBSO serves as the balancing authority and reliability coordinator for N. ME.

Island of Newfoundland

The Island of Newfoundland has an isolated system with NLH as the provider of bulk transmission services and the primary supplier of generation for the isolated interconnected island electrical system. Reliable operation of the Island system whether for energy delivery, response to contingencies, performance of maintenance, or system restoratio is achieved through adherence to operating standards developed by NLH, and administered by its system operations personnel within the NLH Energy Control Centre. NLH acts as the province's balancing and control authority as well as its reliability coordinator.

Labrador

NLH coordinates operations with Churchill Falls Labrador Corporation (CFLCo) for all of Labrador retail, industrial and export power. CFLCo operates a 735KV system for deliveries to Hydro Quebec for the bulk of its 5428MW generation capacity with the remainder being delivered to the mining industry in Labrador City and the town of Happy Valley-Goose Bay. There are many small diesel systems in isolated communities along the coastline.

Quebec

Quebec's crown-owned utility, Hydro Quebec, has one of the largest electricity systems in North America and is an integral part of the NERC and NPCC's transmission oversight system. Hydro Quebec has an established Standard of Conduct to establish the protocols required by the various international agencies. The role of the provincial regulator, the Regie de l'energie, includes watchdog powers over the application of mandatory transmission system reliability standards.

New England

The various states in the New England area operate their transmission systems under an organization they set up as an “independent system operator (ISO). It is known as ISO-New England (ISO-NE) which is a regional transmission organization (RTO), serving Connecticut, Maine, Massachusetts, New Hampshire, Rhode Island and Vermont. ISO-NE is an independent, not-for-profit corporation. ISO-NE meets the electricity demands of the region's economy and people by fulfilling three primary responsibilities to ensure minute-to-minute reliable operation of New England's bulk electric power system:

- Provision of centrally dispatched direction for the generation and flow of electricity across the region's interstate high-voltage transmission lines;
- Development, oversight and fair administration of New England's wholesale electricity marketplace; and
- Management of comprehensive bulk electric power system and wholesale markets' planning processes that address New England's electricity needs well into the future.

Schedule 5: Matrix of Regional Electricity Systems Operations Options

This matrix is intended to outline the issues and considerations facing Atlantic Canada public policy makers when they consider the options for structuring the future of the bulk transmission system operations in the region. The current system will change assuming the New Brunswick Energy Blueprint stated policy of returning many of the New Brunswick System Operator ("NBSO") functions to NB Power is implemented. The NBSO currently performs services for the Maritime Provinces area and Northern Maine, and the proposed changes will require utilities, governments, and regulators to consider how these and possibly other system operations services can be best managed in the future.

This considerations and options matrix provides an overview of the current situation, the identified options for possible future consideration, and describes some of the factors and issues that might face regional system operations under each of these options. The matrix is a summary, and there is a great deal more information available concerning each of the options and related topics.

The regional system operations options are more completely explained in the AEG "Overview Paper on Regional Electricity System Operations." A brief definition of each of the identified Options follows:

Enhanced Regional Systems Coordination allows cooperating on policy and limited technical coordination without having direct involvement in the operations of the individual utility transmission systems. Coordination could be through separate bilateral agreements between pairs of utilities (like the coordination agreement between NBSO and NS Power), or could be a multiparty agreement. Such an arrangement could also provide governments and utilities with an approach to producing common research papers on policy initiatives, and technical and R&D reviews focused on topics such as improving the performance of the region's electricity market, and on some degree of regional planning, standards development, and compliance enforcement.

Independent System Administrator ("ISA") structure allows individual system owners/operators to maintain operating control of their transmission systems while entering into a multilateral agreement that establishes an administrator (i.e. an ISA) to oversee agreements that establish rules agreed upon by participants in the system, including operators, utilities, governments and regulators. These agreements establish the rules, penalties, and roles of participants and other key elements of operating a system within the region. The structure and the operating functions that are to be coordinated by an ISA are determined by negotiations among the affected utilities, regulators, and governments. An ISA can take a role extending from administration, through to hands-on system involvement. A hands-on role would require “tools” to carry out this role. There are no defined restrictions on what can be included in an ISA structure, including possibly incorporating an independent system operator role.

Independent System Operator (“ISO”) is an organization formed to coordinate, control, and monitor the operation of the bulk transmission system for a defined region. An ISO operates a region's electricity grid (either directly through a central control centre or through satellite centres, or through both); develops and administers the region's transmission tariffs and wholesale electricity markets, and provides reliability planning for the jurisdiction’s bulk electricity system. The extent of an ISO’s role is established through multilateral agreements among the participants that are approved by regulators, or more likely in the case of Atlantic Canada, through legislation.

System Operations Considerations and Issues	Current Situation (NB Energy Blueprint ("NBEB") impact is assumed)	Enhanced Regional System Coordination ("ERSC")	Independent System Administrator (ISA)	Independent System Operator (ISO)
1. General	Current	ERSC	ISA	ISO
a. Regional Operations	Currently overall regional responsibilities are not addressed collectively which raises the risk that beneficial issues and opportunities are overlooked or understated.	Agreements once struck leads to a level of certainty, but the concern is conflicting individual priorities could prevent agreement.	Independent oversight of agreements would allow specific areas of cooperation to be defined and coordinated toward established objectives	When mandates are clearly defined in policy, and stakeholders accept and adhere to those mandates, ISO reduces the risk of regional issues and opportunities being overlooked
b. Efficiency	Currently certain roles performed in each jurisdiction could be more efficiently performed by a single identity , leading to greater efficiencies due to economies of scale.(NBEP ends role of NBSO).	Coordination agreements that lead to greater cooperation, or sharing, of functions could lead to greater efficiency (reserve sharing as done today is an example),	Independent oversight of areas of greatest opportunity could be established by agreements and operating plans to achieve benefits through coordinated efforts	Potential for greater efficiencies due to economies of scale with respect to the functions that are performed centrally for the region.

2.	System Planning Requirements	Current	ERSC	ISA	ISO
a.	Planning Reliability Coordinator * (the functional entity that coordinates, facilitates, integrates and evaluates (generally one year and beyond) transmission facility and service plans)	Provincial approach with individual utilities and NBSO responsible in their province (NB Power takes over in NBEB)	As a planning function This function could be carried on by way of agreement which would require the sharing of relevant information, Currently NBSO files with NPCC , Maritimes Area Adequacy reports	Independent planning function could be carried on by way of agreement which would require the sharing of information. The function would not affect the operation of individual systems.	Identified in the NERC Version 5 Reliability Functional Model as function for an ISO to undertake
b.	Resource Planner* (the functional entity that develops a long term (generally one year and beyond) plan for the resource adequacy of specific loads (customer demand and energy requirements) within a resource planning area)	Individual utilities undertake. (No change in NBEB)	As a planning function could be carried on by way of agreement which would require the sharing of relevant information	As a planning function could be carried on by way of agreement which would require the sharing of information. The function would not affect the operation of individual systems.	See comment in 2 a. ISO
c.	Transmission Planner* (the functional entity that develops a long term (generally one year and beyond) plan for the reliability (adequacy) of the interconnected bulk electric transmission systems within a Transmission Planner area) **Function that could be affected by FERC Order 1000 (see Sec 3)f)*	Individual utilities and NBSO each responsible in their province (NB Power takes over in NBEP)	As a planning function could be carried on by way of agreement which would require the sharing of relevant information	As a planning function could be carried on by way of agreement which would require the sharing of information. The function would not affect the operation of individual systems.	See comment in 2 a. ISO

3. Regulatory Requirements	Current	ERSC	ISA	ISO
Provincial				
a. Transmission Rate Structuring (all provinces operate an OATT in order to sell into the US market)	Each province establishes policy and provides direction to the provincial regulator who establishes rate structure	Coordination of OATT and other tariffs policy could allow a reduction in system costs, and common regulatory approach could be defined where needed	Independent oversight of common operating agreements could lead to efficiency in costs and approaches to sharing costs rather than duplication	An ISO with a regional dispatch could create transparent, competitive costs which could be used by any of the provinces to establish innovative rate structures (eg real-time pricing).
b. Environmental Standards	Each province establishes targets and develops strategies for their own jurisdiction	Regional approach by agreement could allow environmental targets for the generation sector to be reached regionally with maximum efficiency	Independent oversight of regional system agreements could allow for a cost/benefit formula to establish dispatch on a regional approach	ISO would be responsible for implementing established targets that if not coordinated could add emissions and costs
Federal				
c. National Energy Board ("NEB")	Utilities seek their own permits, if needed, for particular projects	Project specific agreements could allow for a regional approach to multi province actions	Not an ongoing requirement as permitting is project specific	Not an ongoing requirement as permitting is project specific
d. Environmental Legislation(ie coal generation regulations)	Each province manages it own implementation and relationship with the federal government	Agreement could allow a regional approach to federal requirements resulting in a more efficient and timely approach.	Oversight of the electricity role in agreement implementation could be undertaken. Advice on regional approaches would be available.	An ISO structure could take direction on environmental emission reduction as a determining element in system operation.
International				
e. International Standards (FERC, NERC etc.)	NBSO manages many aspects of the standards and provincial regulators with individual agreements address others (NBEB will affect region's approach)	Regional approach by agreement would provide efficient approach to regulatory requirements as noted in System Operation requirements below (see Sec.	Agreements on regional approach, monitoring and reporting could reduce cost and improve efficiency as noted in System Operations requirements below. (see Sec.	Identified in the NERC Version 5 Reliability Functional Model as a function for an ISO to undertake

f.	FERC Order 1000 (see System Planning Requirements Sec 2)	Final FERC Order just established and no application experience to determine cost or role requirement	4) As a planning function could be accomplished by agreement and the sharing of necessary information.	4) As a planning function could be carried on by way of agreement which would require the sharing of information. The function would not affect the operation of individual systems.	See comment in 3 e. ISO

4.	***System Operation Considerations***	Current	ERSC	ISA	ISO
a.	Reliability Coordination (Transmission owners are obligated to provide real-time information and equipment limitations to the Reliability Coordinator.)	NBSO undertakes this role for the Maritime Provinces Area and Northern Maine, subject to an agreement(NBEB eliminates current NBSO role)	Coordination agreements existed pre NBSO and are needed to meet regulatory requirements. Post Muskrat Falls NL may need to be added.	A technical operation if undertaken regionally requiring “tools” to undertake monitoring and enforcement of coordination agreement but would not conduct system operation as utilities would be bound to follow direction.	A typical ISO performs the Reliability Coordination function. A typical ISO has the tools and information about the system which it operates (and its neighbours system) to allow it to perform this function.
b.	Balancing (Supply and Demand)	NBSO balances with NB P resources supply and demand for NB/PEI/N.ME. NSPSO balances for NS. NALCOR balances for the island of NL. resources.(NBEB change could affect the current arrangement)	A regional balancing agreement (similar to NB/PEI/NME)would require mandatory participation and provision of regional balancing information about the real-time supply and demand, the availability and cost of balancing resources to a selected utility to conduct the balancing dispatch.	A coordination agreement would require mandatory participation and provision of necessary information and the ISA would do the balancing dispatch and direct the utilities to follow . It would not have any real time control unless the necessary tools are provided.	A typical ISO would assess the need for balancing resources outside bilateral agreements and have adequate information about availability and cost of balancing resources. The ISO would select the optimum combination of resources to be ready to provide the service and then dispatch energy from those resources as required. . It would have real time control of many resources and directional control of others.
c.	Resource Adequacy	Each province’s utility or SO assesses the ability of resources to meet the	Current coordination agreements would be replaced and could expand to	Agreement could allow for the development of a regional resource adequacy plan based	A typical ISO would set resource adequacy criteria for the region served (or zonal as

		respective provincial peak demands. The onus to procure adequate electricity is on the respective load-serving utility and the regulatory regime. NBSO conducts Maritimes Area Resource Adequacy analysis as part of its reliability coordinator role and files it with NPCC. (Under NBEB utilities will need new agreements)	include NL It may be possible to plan to meet a regional peak need, but a fair and deterministic method of allocating the needs to the respective provinces would be required. A robust agreement would be required on how to establish and allocate the regional requirement including taking into account transmission constraints.	on a pre determined criteria. An ISA could do everything for resource adequacy that an ISO would do.	dictated by transmission congestion) subject to mandatory reliability standards. An ISO would typically have the data to perform this assessment and would be doing so from an independent perspective. Transparent process, stakeholder and regulatory oversight bolster the robustness and integrity of the process.
d.	Operating Reserves	A negotiated resource sharing in the Maritime Provinces Region currently reduces total requirements, but there is no dynamic optimization of the sharing. (NBEB could affect the current arrangement)	Coordinated dynamic optimization may be possible by agreement, but would require at least one entity to have all of the relevant information including costs.	A regional agreement would require mandatory participation and provision of necessary information to the ISA which would do the scheduling (and possibly dynamic optimization) and direct the utilities to follow it. It would not have any real time control unless the tools were provided.	A typical ISO would establish regional (and zonal as required) reserve requirements and dynamically optimize the selection of resources to meet those requirements. . It would have real time control of many resources and directional control of others.
e.	Tariff Design	Each province has a separate tariff designed by the utility and approved by the provincial regulator. (Design by NBSO will pass to NB Power under NBEB)	A single coordinated tariff is unlikely through utility agreement. Also, any cost allocation on a regional basis would require local regulatory approvals which may not have authority to make such decisions and furthermore would require	An ISA could independently develop a regional tariff design but would need legislative changes for regulatory approvals.	An ISO, similar to an ISA, could independently develop a regional tariff design but would need legislative changes for regulatory approvals.

4.	***System Operation Considerations***	Current	ERSC	ISA	ISO
a.	Reliability Coordination (Transmission owners are obligated to provide real-time information and equipment limitations to the Reliability Coordinator.)	NBSO undertakes this role for the Maritime Provinces Area and Northern Maine, subject to an agreement(NBEB eliminates current NBSO role)	Coordination agreements existed pre NBSO and are needed to meet regulatory requirements. Post Muskrat Falls NL may need to be added.	A technical operation if undertaken regionally requiring "tools" to undertake monitoring and enforcement of coordination agreement but would not conduct system operation as utilities would be bound to follow direction.	A typical ISO performs the Reliability Coordination function. A typical ISO has the tools and information about the system which it operates (and its neighbours system) to allow it to perform this function.
b.	Balancing (Supply and Demand)	NBSO balances with NB P resources supply and demand for NB/PEI/N.ME. NSPSO balances for NS. NALCOR balances for the island of NL. resources.(NBEB change could affect the current arrangement)	A regional balancing agreement (similar to NB/PEI/NME)would require mandatory participation and provision of regional balancing information about the real-time supply and demand, the availability and cost of balancing resources to a selected utility to conduct the balancing dispatch.	A coordination agreement would require mandatory participation and provision of necessary information and the ISA would do the balancing dispatch and direct the utilities to follow . It would not have any real time control unless the necessary tools are provided.	A typical ISO would assess the need for balancing resources outside bilateral agreements and have adequate information about availability and cost of balancing resources. The ISO would select the optimum combination of resources to be ready to provide the service and then dispatch energy from those resources as required. . It would have real time control of many resources and directional control of others.
c.	Resource Adequacy	Each province's utility or SO assesses the ability of resources to meet the	Current coordination agreements would be replaced and could expand to	Agreement could allow for the development of a regional resource adequacy plan based	A typical ISO would set resource adequacy criteria for the region served (or zonal as

		respective provincial peak demands. The onus to procure adequate electricity is on the respective load-serving utility and the regulatory regime. NBSO conducts Maritimes Area Resource Adequacy analysis as part of its reliability coordinator role and files it with NPCC. (Under NBEB utilities will need new agreements)	include NL It may be possible to plan to meet a regional peak need, but a fair and deterministic method of allocating the needs to the respective provinces would be required. A robust agreement would be required on how to establish and allocate the regional requirement including taking into account transmission constraints.	on a pre determined criteria. An ISA could do everything for resource adequacy that an ISO would do.	dictated by transmission congestion) subject to mandatory reliability standards. An ISO would typically have the data to perform this assessment and would be doing so from an independent perspective. Transparent process, stakeholder and regulatory oversight bolster the robustness and integrity of the process.
d.	Operating Reserves	A negotiated resource sharing in the Maritime Provinces Region currently reduces total requirements, but there is no dynamic optimization of the sharing. (NBEB could affect the current arrangement)	Coordinated dynamic optimization may be possible by agreement, but would require at least one entity to have all of the relevant information including costs.	A regional agreement would require mandatory participation and provision of necessary information to the ISA which would do the scheduling (and possibly dynamic optimization) and direct the utilities to follow it. It would not have any real time control unless the tools were provided.	A typical ISO would establish regional (and zonal as required) reserve requirements and dynamically optimize the selection of resources to meet those requirements. . It would have real time control of many resources and directional control of others.
e.	Tariff Design	Each province has a separate tariff designed by the utility and approved by the provincial regulator. (Design by NBSO will pass to NB Power under NBEB)	A single coordinated tariff is unlikely through utility agreement. Also, any cost allocation on a regional basis would require local regulatory approvals which may not have authority to make such decisions and furthermore would require	An ISA could independently develop a regional tariff design but would need legislative changes for regulatory approvals.	An ISO, similar to an ISA, could independently develop a regional tariff design but would need legislative changes for regulatory approvals.

			unanimous approvals from each jurisdiction. Legislation is required.		
f.	Tariff Management	Utilities under Codes of Conduct implement the tariff through OASIS's. Discounting between areas to reduce pancaking is possible but rarely implemented. (Management by NBSO will pass to NB Power under NBEB)	Coordination of a discount mechanism, bilaterally between utilities or multilaterally across the region, is possible and could get regulatory approval. It could be, either in combination with a regional dispatch, or as an attempt to move toward more regional interchanges.	An ISA could independently develop a regional discounting mechanism and obtain regulatory approvals. (A regional tariff is not required for a regional market)	An ISO, similar to an ISA, could independently develop a regional discounting mechanism and obtain regulatory approvals. (A regional tariff is not required for a regional market)
g.	New energy sources entering Atlantic regional market (Muskrat Falls, Lepreau II, tidal, wind)	Current approach is relatively individual other than NPCC reliability requirements.	A regional committee (like the Maritimes Area Technical Planning Committee organized by NBSO) could be formed. Without NBSO the future of MATC is unknown and possibly there will be no one entity having an explicit and exclusive mandate to perform coordination of the necessary work.	A regional ISA could, as a minimum, provide overview coordination in Atlantic Canada and with adjoining Planning Coordinator areas, or be empowered, in addition, to facilitate, integrate and evaluate transmission facility and service plans, and resource plans. Dependent on the "tools" available agreements could establish a mechanism for the ISA to follow in establishing the requirements for the introduction of new capacity based on individual utility strategies.	A regional ISO would be empowered to coordinate, facilitate, integrate and evaluate transmission facility and service plans, and resource plans within Atlantic Canada and coordinates those plans with adjoining Planning Coordinator areas.

			unanimous approvals from each jurisdiction. Legislation is required.		
f.	Tariff Management	Utilities under Codes of Conduct implement the tariff through OASIS's. Discounting between areas to reduce pancaking is possible but rarely implemented. (Management by NBSO will pass to NB Power under NBEB)	Coordination of a discount mechanism, bilaterally between utilities or multilaterally across the region, is possible and could get regulatory approval. It could be, either in combination with a regional dispatch, or as an attempt to move toward more regional interchanges.	An ISA could independently develop a regional discounting mechanism and obtain regulatory approvals. (A regional tariff is not required for a regional market)	An ISO, similar to an ISA, could independently develop a regional discounting mechanism and obtain regulatory approvals. (A regional tariff is not required for a regional market)
g.	New energy sources entering Atlantic regional market (Muskrat Falls, Lepreau II, tidal, wind)	Current approach is relatively individual other than NPCC reliability requirements.	A regional committee (like the Maritimes Area Technical Planning Committee organized by NBSO) could be formed. Without NBSO the future of MATC is unknown and possibly there will be no one entity having an explicit and exclusive mandate to perform coordination of the necessary work.	A regional ISA could, as a minimum, provide overview coordination in Atlantic Canada and with adjoining Planning Coordinator areas, or be empowered, in addition, to facilitate, integrate and evaluate transmission facility and service plans, and resource plans. Dependent on the "tools" available agreements could establish a mechanism for the ISA to follow in establishing the requirements for the introduction of new capacity based on individual utility strategies.	A regional ISO would be empowered to coordinate, facilitate, integrate and evaluate transmission facility and service plans, and resource plans within Atlantic Canada and coordinates those plans with adjoining Planning Coordinator areas.

Schedule 5: Matrix of Regional Electricity Systems Operations Options

This matrix is intended to outline the issues and considerations facing Atlantic Canada public policy makers when they consider the options for structuring the future of the bulk transmission system operations in the region. The current system will change assuming the New Brunswick Energy Blueprint stated policy of returning many of the New Brunswick System Operator ("NBSO") functions to NB Power is implemented. The NBSO currently performs services for the Maritime Provinces area and Northern Maine, and the proposed changes will require utilities, governments, and regulators to consider how these and possibly other system operations services can be best managed in the future.

This considerations and options matrix provides an overview of the current situation, the identified options for possible future consideration, and describes some of the factors and issues that might face regional system operations under each of these options. The matrix is a summary, and there is a great deal more information available concerning each of the options and related topics.

The regional system operations options are more completely explained in the AEG "Overview Paper on Regional Electricity System Operations." A brief definition of each of the identified Options follows:

Enhanced Regional Systems Coordination allows cooperating on policy and limited technical coordination without having direct involvement in the operations of the individual utility transmission systems. Coordination could be through separate bilateral agreements between pairs of utilities (like the coordination agreement between NBSO and NS Power), or could be a multiparty agreement. Such an arrangement could also provide governments and utilities with an approach to producing common research papers on policy initiatives, and technical and R&D reviews focused on topics such as improving the performance of the region's electricity market, and on some degree of regional planning, standards development, and compliance enforcement.

Independent System Administrator ("ISA") structure allows individual system owners/operators to maintain operating control of their transmission systems while entering into a multilateral agreement that establishes an administrator (i.e. an ISA) to oversee agreements that establish rules agreed upon by participants in the system, including operators, utilities, governments and regulators. These agreements establish the rules, penalties, and roles of participants and other key elements of operating a system within the region. The structure and the operating functions that are to be coordinated by an ISA are determined by negotiations among the affected utilities, regulators, and governments. An ISA can take a role extending from administration, through to hands-on system involvement. A hands-on role would require "tools" to carry out this role. There are no defined restrictions on what can be included in an ISA structure, including possibly incorporating an independent system operator role.

Independent System Operator ("ISO") is an organization formed to coordinate, control, and monitor the operation of the bulk transmission system for a defined region. An ISO operates a region's electricity grid (either directly through a central control centre or through satellite centres, or through both); develops and administers the region's transmission tariffs and wholesale electricity markets, and provides reliability planning for the jurisdiction's bulk electricity system. The extent of an ISO's role is established through multilateral agreements among the participants that are approved by regulators, or more likely in the case of Atlantic Canada, through legislation.

System Operations Considerations and Issues	Current Situation (NB Energy Blueprint ("NBEB") impact is assumed)	Enhanced Regional System Coordination ("ERSC")	Independent System Administrator (ISA)	Independent System Operator (ISO)
1. General	Current	ERSC	ISA	ISO
a. Regional Operations	Currently overall regional responsibilities are not addressed collectively which raises the risk that beneficial issues and opportunities are overlooked or understated.	Agreements once struck leads to a level of certainty, but the concern is conflicting individual priorities could prevent agreement.	Independent oversight of agreements would allow specific areas of cooperation to be defined and coordinated toward established objectives	When mandates are clearly defined in policy, and stakeholders accept and adhere to those mandates, ISO reduces the risk of regional issues and opportunities being overlooked
b. Efficiency	Currently certain roles performed in each jurisdiction could be more efficiently performed by a single identity , leading to greater efficiencies due to economies of scale.(NBEP ends role of NBSO).	Coordination agreements that lead to greater cooperation, or sharing, of functions could lead to greater efficiency (reserve sharing as done today is an example),	Independent oversight of areas of greatest opportunity could be established by agreements and operating plans to achieve benefits through coordinated efforts	Potential for greater efficiencies due to economies of scale with respect to the functions that are performed centrally for the region.

2.	System Planning Requirements	Current	ERSC	ISA	ISO
a.	Planning Reliability Coordinator * (the functional entity that coordinates, facilitates, integrates and evaluates (generally one year and beyond) transmission facility and service plans)	Provincial approach with individual utilities and NBSO responsible in their province (NB Power takes over in NBEB)	As a planning function This function could be carried on by way of agreement which would require the sharing of relevant information, Currently NBSO files with NPCC , Maritimes Area Adequacy reports	Independent planning function could be carried on by way of agreement which would require the sharing of information. The function would not affect the operation of individual systems.	Identified in the NERC Version 5 Reliability Functional Model as function for an ISO to undertake
b.	Resource Planner* (the functional entity that develops a long term (generally one year and beyond) plan for the resource adequacy of specific loads (customer demand and energy requirements) within a resource planning area)	Individual utilities undertake. (No change in NBEB)	As a planning function could be carried on by way of agreement which would require the sharing of relevant information	As a planning function could be carried on by way of agreement which would require the sharing of information. The function would not affect the operation of individual systems.	See comment in 2 a. ISO
c.	Transmission Planner* (the functional entity that develops a long term (generally one year and beyond) plan for the reliability (adequacy) of the interconnected bulk electric transmission systems within a Transmission Planner area) **Function that could be affected by FERC Order 1000 (see Sec 3)f)*	Individual utilities and NBSO each responsible in their province (NB Power takes over in NBEP)	As a planning function could be carried on by way of agreement which would require the sharing of relevant information	As a planning function could be carried on by way of agreement which would require the sharing of information. The function would not affect the operation of individual systems.	See comment in 2 a. ISO

System Operations Considerations and Issues	Current Situation (NB Energy Blueprint ("NBEB") impact is assumed)	Enhanced Regional System Coordination ("ERSC")	Independent System Administrator (ISA)	Independent System Operator (ISO)
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3. Regulatory Requirements	Current	ERSC	ISA	ISO
Provincial				
a. Transmission Rate Structuring (all provinces operate an OATT in order to sell into the US market)	Each province establishes policy and provides direction to the provincial regulator who establishes rate structure	Coordination of OATT and other tariffs policy could allow a reduction in system costs, and common regulatory approach could be defined where needed	Independent oversight of common operating agreements could lead to efficiency in costs and approaches to sharing costs rather than duplication	An ISO with a regional dispatch could create transparent, competitive costs which could be used by any of the provinces to establish innovative rate structures (eg real-time pricing).
b. Environmental Standards	Each province establishes targets and develops strategies for their own jurisdiction	Regional approach by agreement could allow environmental targets for the generation sector to be reached regionally with maximum efficiency	Independent oversight of regional system agreements could allow for a cost/benefit formula to establish dispatch on a regional approach	ISO would be responsible for implementing established targets that if not coordinated could add emissions and costs
Federal				
c. National Energy Board ("NEB")	Utilities seek their own permits, if needed, for particular projects	Project specific agreements could allow for a regional approach to multi province actions	Not an ongoing requirement as permitting is project specific	Not an ongoing requirement as permitting is project specific
d. Environmental Legislation(ie coal generation regulations)	Each province manages it own implementation and relationship with the federal government	Agreement could allow a regional approach to federal requirements resulting in a more efficient and timely approach.	Oversight of the electricity role in agreement implementation could be undertaken. Advice on regional approaches would be available.	An ISO structure could take direction on environmental emission reduction as a determining element in system operation.
International				
e. International Standards (FERC, NERC etc.)	NBSO manages many aspects of the standards and provincial regulators with individual agreements address others (NBEB will affect region's approach)	Regional approach by agreement would provide efficient approach to regulatory requirements as noted in System Operation requirements below (see Sec.	Agreements on regional approach, monitoring and reporting could reduce cost and improve efficiency as noted in System Operations requirements below. (see Sec.	Identified in the NERC Version 5 Reliability Functional Model as a function for an ISO to undertake

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f.	FERC Order 1000 (see System Planning Requirements Sec 2)	Final FERC Order just established and no application experience to determine cost or role requirement	4) As a planning function could be accomplished by agreement and the sharing of necessary information.	4) As a planning function could be carried on by way of agreement which would require the sharing of information. The function would not affect the operation of individual systems.	See comment in 3 e. ISO

4.	***System Operation Considerations***	Current	ERSC	ISA	ISO
a.	Reliability Coordination (Transmission owners are obligated to provide real-time information and equipment limitations to the Reliability Coordinator.)	NBSO undertakes this role for the Maritime Provinces Area and Northern Maine, subject to an agreement(NBEB eliminates current NBSO role)	Coordination agreements existed pre NBSO and are needed to meet regulatory requirements. Post Muskrat Falls NL may need to be added.	A technical operation if undertaken regionally requiring "tools" to undertake monitoring and enforcement of coordination agreement but would not conduct system operation as utilities would be bound to follow direction.	A typical ISO performs the Reliability Coordination function. A typical ISO has the tools and information about the system which it operates (and its neighbours system) to allow it to perform this function.
b.	Balancing (Supply and Demand)	NBSO balances with NB P resources supply and demand for NB/PEI/N.ME. NSPSO balances for NS. NALCOR balances for the island of NL. resources.(NBEB change could affect the current arrangement)	A regional balancing agreement (similar to NB/PEI/NME)would require mandatory participation and provision of regional balancing information about the real-time supply and demand, the availability and cost of balancing resources to a selected utility to conduct the balancing dispatch.	A coordination agreement would require mandatory participation and provision of necessary information and the ISA would do the balancing dispatch and direct the utilities to follow . It would not have any real time control unless the necessary tools are provided.	A typical ISO would assess the need for balancing resources outside bilateral agreements and have adequate information about availability and cost of balancing resources. The ISO would select the optimum combination of resources to be ready to provide the service and then dispatch energy from those resources as required. . It would have real time control of many resources and directional control of others.
c.	Resource Adequacy	Each province's utility or SO assesses the ability of resources to meet the	Current coordination agreements would be replaced and could expand to	Agreement could allow for the development of a regional resource adequacy plan based	A typical ISO would set resource adequacy criteria for the region served (or zonal as

		respective provincial peak demands. The onus to procure adequate electricity is on the respective load-serving utility and the regulatory regime. NBSO conducts Maritimes Area Resource Adequacy analysis as part of its reliability coordinator role and files it with NPCC. (Under NBEB utilities will need new agreements)	include NL It may be possible to plan to meet a regional peak need, but a fair and deterministic method of allocating the needs to the respective provinces would be required. A robust agreement would be required on how to establish and allocate the regional requirement including taking into account transmission constraints.	on a pre determined criteria. An ISA could do everything for resource adequacy that an ISO would do.	dictated by transmission congestion) subject to mandatory reliability standards. An ISO would typically have the data to perform this assessment and would be doing so from an independent perspective. Transparent process, stakeholder and regulatory oversight bolster the robustness and integrity of the process.
d.	Operating Reserves	A negotiated resource sharing in the Maritime Provinces Region currently reduces total requirements, but there is no dynamic optimization of the sharing. (NBEB could affect the current arrangement)	Coordinated dynamic optimization may be possible by agreement, but would require at least one entity to have all of the relevant information including costs.	A regional agreement would require mandatory participation and provision of necessary information to the ISA which would do the scheduling (and possibly dynamic optimization) and direct the utilities to follow it. It would not have any real time control unless the tools were provided.	A typical ISO would establish regional (and zonal as required) reserve requirements and dynamically optimize the selection of resources to meet those requirements. . It would have real time control of many resources and directional control of others.
e.	Tariff Design	Each province has a separate tariff designed by the utility and approved by the provincial regulator. (Design by NBSO will pass to NB Power under NBEB)	A single coordinated tariff is unlikely through utility agreement. Also, any cost allocation on a regional basis would require local regulatory approvals which may not have authority to make such decisions and furthermore would require	An ISA could independently develop a regional tariff design but would need legislative changes for regulatory approvals.	An ISO, similar to an ISA, could independently develop a regional tariff design but would need legislative changes for regulatory approvals.

4.	***System Operation Considerations***	Current	ERSC	ISA	ISO
a.	Reliability Coordination (Transmission owners are obligated to provide real-time information and equipment limitations to the Reliability Coordinator.)	NBSO undertakes this role for the Maritime Provinces Area and Northern Maine, subject to an agreement(NBEB eliminates current NBSO role)	Coordination agreements existed pre NBSO and are needed to meet regulatory requirements. Post Muskrat Falls NL may need to be added.	A technical operation if undertaken regionally requiring “tools” to undertake monitoring and enforcement of coordination agreement but would not conduct system operation as utilities would be bound to follow direction.	A typical ISO performs the Reliability Coordination function. A typical ISO has the tools and information about the system which it operates (and its neighbours system) to allow it to perform this function.
b.	Balancing (Supply and Demand)	NBSO balances with NB P resources supply and demand for NB/PEI/N.ME. NSPSO balances for NS. NALCOR balances for the island of NL. resources.(NBEB change could affect the current arrangement)	A regional balancing agreement (similar to NB/PEI/NME)would require mandatory participation and provision of regional balancing information about the real-time supply and demand, the availability and cost of balancing resources to a selected utility to conduct the balancing dispatch.	A coordination agreement would require mandatory participation and provision of necessary information and the ISA would do the balancing dispatch and direct the utilities to follow . It would not have any real time control unless the necessary tools are provided.	A typical ISO would assess the need for balancing resources outside bilateral agreements and have adequate information about availability and cost of balancing resources. The ISO would select the optimum combination of resources to be ready to provide the service and then dispatch energy from those resources as required. . It would have real time control of many resources and directional control of others.
c.	Resource Adequacy	Each province’s utility or SO assesses the ability of resources to meet the	Current coordination agreements would be replaced and could expand to	Agreement could allow for the development of a regional resource adequacy plan based	A typical ISO would set resource adequacy criteria for the region served (or zonal as

		respective provincial peak demands. The onus to procure adequate electricity is on the respective load-serving utility and the regulatory regime. NBSO conducts Maritimes Area Resource Adequacy analysis as part of its reliability coordinator role and files it with NPCC. (Under NBEB utilities will need new agreements)	include NL It may be possible to plan to meet a regional peak need, but a fair and deterministic method of allocating the needs to the respective provinces would be required. A robust agreement would be required on how to establish and allocate the regional requirement including taking into account transmission constraints.	on a pre determined criteria. An ISA could do everything for resource adequacy that an ISO would do.	dictated by transmission congestion) subject to mandatory reliability standards. An ISO would typically have the data to perform this assessment and would be doing so from an independent perspective. Transparent process, stakeholder and regulatory oversight bolster the robustness and integrity of the process.
d.	Operating Reserves	A negotiated resource sharing in the Maritime Provinces Region currently reduces total requirements, but there is no dynamic optimization of the sharing. (NBEB could affect the current arrangement)	Coordinated dynamic optimization may be possible by agreement, but would require at least one entity to have all of the relevant information including costs.	A regional agreement would require mandatory participation and provision of necessary information to the ISA which would do the scheduling (and possibly dynamic optimization) and direct the utilities to follow it. It would not have any real time control unless the tools were provided.	A typical ISO would establish regional (and zonal as required) reserve requirements and dynamically optimize the selection of resources to meet those requirements. . It would have real time control of many resources and directional control of others.
e.	Tariff Design	Each province has a separate tariff designed by the utility and approved by the provincial regulator. (Design by NBSO will pass to NB Power under NBEB)	A single coordinated tariff is unlikely through utility agreement. Also, any cost allocation on a regional basis would require local regulatory approvals which may not have authority to make such decisions and furthermore would require	An ISA could independently develop a regional tariff design but would need legislative changes for regulatory approvals.	An ISO, similar to an ISA, could independently develop a regional tariff design but would need legislative changes for regulatory approvals.

			unanimous approvals from each jurisdiction. Legislation is required.		
f.	Tariff Management	Utilities under Codes of Conduct implement the tariff through OASIS's. Discounting between areas to reduce pancaking is possible but rarely implemented. (Management by NBSO will pass to NB Power under NBEB)	Coordination of a discount mechanism, bilaterally between utilities or multilaterally across the region, is possible and could get regulatory approval. It could be, either in combination with a regional dispatch, or as an attempt to move toward more regional interchanges.	An ISA could independently develop a regional discounting mechanism and obtain regulatory approvals. (A regional tariff is not required for a regional market)	An ISO, similar to an ISA, could independently develop a regional discounting mechanism and obtain regulatory approvals. (A regional tariff is not required for a regional market)
g.	New energy sources entering Atlantic regional market (Muskrat Falls, Lepreau II, tidal, wind)	Current approach is relatively individual other than NPCC reliability requirements.	A regional committee (like the Maritimes Area Technical Planning Committee organized by NBSO) could be formed. Without NBSO the future of MATC is unknown and possibly there will be no one entity having an explicit and exclusive mandate to perform coordination of the necessary work.	A regional ISA could, as a minimum, provide overview coordination in Atlantic Canada and with adjoining Planning Coordinator areas, or be empowered, in addition, to facilitate, integrate and evaluate transmission facility and service plans, and resource plans. Dependent on the "tools" available agreements could establish a mechanism for the ISA to follow in establishing the requirements for the introduction of new capacity based on individual utility strategies.	A regional ISO would be empowered to coordinate, facilitate, integrate and evaluate transmission facility and service plans, and resource plans within Atlantic Canada and coordinates those plans with adjoining Planning Coordinator areas.

			unanimous approvals from each jurisdiction. Legislation is required.		
f.	Tariff Management	Utilities under Codes of Conduct implement the tariff through OASIS's. Discounting between areas to reduce pancaking is possible but rarely implemented. (Management by NBSO will pass to NB Power under NBEB)	Coordination of a discount mechanism, bilaterally between utilities or multilaterally across the region, is possible and could get regulatory approval. It could be, either in combination with a regional dispatch, or as an attempt to move toward more regional interchanges.	An ISA could independently develop a regional discounting mechanism and obtain regulatory approvals. (A regional tariff is not required for a regional market)	An ISO, similar to an ISA, could independently develop a regional discounting mechanism and obtain regulatory approvals. (A regional tariff is not required for a regional market)
g.	New energy sources entering Atlantic regional market (Muskrat Falls, Lepreau II, tidal, wind)	Current approach is relatively individual other than NPCC reliability requirements.	A regional committee (like the Maritimes Area Technical Planning Committee organized by NBSO) could be formed. Without NBSO the future of MATC is unknown and possibly there will be no one entity having an explicit and exclusive mandate to perform coordination of the necessary work.	A regional ISA could, as a minimum, provide overview coordination in Atlantic Canada and with adjoining Planning Coordinator areas, or be empowered, in addition, to facilitate, integrate and evaluate transmission facility and service plans, and resource plans. Dependent on the "tools" available agreements could establish a mechanism for the ISA to follow in establishing the requirements for the introduction of new capacity based on individual utility strategies.	A regional ISO would be empowered to coordinate, facilitate, integrate and evaluate transmission facility and service plans, and resource plans within Atlantic Canada and coordinates those plans with adjoining Planning Coordinator areas.

h. Loss Optimization	Loss optimization is part of the dispatch strategy in each area but there is no regional loss optimization in the scheduling of energy by market participants or in the real-time dispatch of resources.	While not impossible, it is improbable that coordination agreements would allow for a regional optimization of losses. It would require a coordinated "central dispatch", but would also require that the one entity that is performing the dispatch also performs the loss optimization.	An ISA could perform loss optimization within the optimized dispatch function. This could be done within a physical bilateral market with resulting schedules communicated to separate utility SO's to implement or dependent on "tools" available the ISA could be charged through agreements to manage the system to minimize the loss dependent on the framework established for system operation.	An ISO would be expected to perform a loss optimization within the optimized dispatch function. In the case of a physical bilateral market, similar to an ISA the economic dispatch would take losses into account and have minimum total costs as the objective function.
i. Central Dispatch	There is currently no centralized regional optimization of energy dispatch. NBSO performs a centralized security constrained economic dispatch of resources in NB and has the ability to economically dispatch resources that are registered in the NB market but are located outside of NB. (With NBEB separate dispatches would continue.)	Coordinated regional optimization of energy dispatch could be established by agreement but would require at least one entity to have all of the current relevant information including confidential costs and capabilities in order to make a determination of the optimum dispatch of resources. One entity would need to have exclusive legal authority through a multilateral coordination agreement to dispatch resources in each utility.	An ISA could perform an independent regional/zonal energy dispatch similar to an ISO and communicate hourly schedules to each utility. Real time dispatch and control is dependent on "tools" available to ISA. There could be agreement on a dispatch criteria to maximize the benefit for all utilities dependent on the agreement dispatch criteria	An ISO would perform a regional (and zonal as required) energy dispatch taking into account total needs and cost information for all resources. An ISO would typically have the data(and control capability) to perform security-constrained economic dispatch , both hourly and in real time, and would be doing so from an independent perspective.
j. Unit Commitment	There is no centralized	Coordinated unit	Agreement could establish	A typical ISO would perform

	regional optimization of unit commitment. Bilateral market transactions can result in reduced unit commitment costs but are impeded by incomplete resource information and marketers' transaction costs.	commitment could be established by agreement, but would require at least one entity to have all of the relevant information including costs in order to make a determination of the optimum commitment of resources.	the responsibility in the ISA, dependent on the "tools" available, to direct the agreed criteria upon which the generation units would be dispatched to meet the agreement objectives	a regional (and zonal as required) unit commitment taking into account total needs and cost information for all resources. An ISO would typically have the data to perform unit commitment and would be doing so from an independent perspective.
k. Operational Efficiencies	In addition to performing the Reliability Coordinator function for the Maritime Provinces and Northern Maine, , NBSO has also taken on OASIS hosting for NSPI and E-Tagging for other entities. (NBEB eliminates NBSO which would require a new approach).	Some additional system operator activities could be centralized or coordinated through agreements.	An ISA could perform most of the necessary functions with a clear exception being real time operations without the necessary "tools". Dependent on the "tools' available, the agreements could establish a criteria to direct the operation of the system to achieve efficiencies without interfering with individual utilities operating strategies	A typical ISO performs many functions for the region served including the following functions from the NERC functional model: Planning Reliability, Resource Planning, Transmission Planning, Operating Reliability, Interchange, Balancing, Market Operations, Transmission Service.

5.	***Public Policy Elements***	Current	ERSC	ISA	ISO
a.	Coordination of regulatory requirements respecting system operating principles	Limited discussion among provinces	As a government policy function the task could be accomplished by regional agreement	Once government agreements have been developed establishing operating principles could be a primary responsibility for an ISA	A region approach could mandate a common and legislated approach to system operations for the ISO to use in operating practises
b.	Regional emission management approaches	Limited discussion among provinces	As a policy planning or coordination function the task could be accomplished by agreement and the sharing of information.	Agreement could allow for ISA to assist in policy development and have responsibility for independent oversight of electricity sector implementation	ISO role focus would be on implementation of regional policies directed toward the electricity sector using tools including dispatch, balancing etc.
c.	Public Policy Developer role in FERC Order 1000	New FERC Order requiring interpretation	As a government function the task could be accomplished by agreement among provinces and the sharing of necessary information.	A role clearly established to be responsibility of government. Implementation and verification could be an agreed upon task of ISA	A role clearly established to be responsibility of government. Implementation and verification would be a direct responsibility of ISO.
d.	Consumer Awareness and Education	Each jurisdiction seeks to better educate consumers (eg. see NBEB).	Agreements involving the provinces and/or utilities for education and awareness programs (e.g. an "Atlantic Electricity Working Group") could be structured to increase reach and frequency of information.	Regional Agreements could assign responsibility to ISO to implement the agreed upon messages .	A regional ISO would be providing transparency and interpretation of information related to the region's bulk power system (e.g. real-time marginal energy and ancillaries' prices, locational constraints). Limited role in direct consumer contact but

					could be added if parties directed.
e.	Smart Grid (including load control, customer participation, electric vehicles, R&D, renewables integration.)	Atlantic Powershift is an example of how regional collaboration can be achieved through agreement. Future development has not been determined.	Regional agreements could allow for implementation of cooperative approach to smart grid applications with individual system, operators responsible for application.	An ISO could over see a regional agreement to ensure costs and benefits are identified for the utilities" but would need utilities to implement real time controls if tools were not in their control.	A regional ISO could be integral to the bulk power system aspects of smart grid (e.g. realtime price signals). Additional Smart Grid functions could be asked of the ISO by policy-makers (e.g. R&D).

Renewable Generation Supply Chain Opportunities in Atlantic Canada

Prepared for the Atlantic Energy Gateway Initiative
of the
Atlantic Canada Opportunities Agency

March 30, 2012

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Executive Summary

Introduction

Members of the Atlantic Energy Gateway ("AEG") have asked Concentric Energy Advisors, Inc. ("Concentric") to examine a range of issues associated with opportunities for Atlantic Canadian firms in the supply chain for various renewable generation technologies, including:

- Onshore wind;
- Offshore wind;
- Tidal energy;
- Biomass energy; and
- Systems to power remote on- and off-grid communities.

As directed by the AEG, this report explores the following questions related to each of these technologies:

1. What are the major supply chain constraints in Atlantic Canada today?
2. Which elements of the above supply chains are presently or can evolve as major challenges to further Atlantic Canadian business development/deployment?
3. What solutions/best practices might governments and the private sector look to in order to address these constraints?
4. Based on a review of capacity in Atlantic Canada, what are the best opportunities for firms in Atlantic Canada to access these supply chains in order to generate new sales?

Methodology

Concentric conducted this study using a two-tiered approach. First, a literature review of existing studies evaluating renewable energy supply chains was performed to establish a base of knowledge on the subject. A bibliography of Concentric's primary documentation sources is contained Appendix B.

Concentric then also conducted extensive phone interviews with industry participants, trade organizations, and electric utilities in Atlantic Canada to provide an enhanced local context to its analysis. While these interviews influenced Concentric's assessments, all of the opinions and conclusions in this report are attributable to Concentric. A listing of Concentric's interviews is provided in Appendix A.

While the definition of a "renewable energy supply chain" may include upstream activities such as research and development, resource studies, site preparation, environmental assessments, etc., for the purposes of this report, Concentric has limited the definition of the supply chain to those activities commencing with the manufacture of plant components (or in the case of biomass, the procurement of plant feedstock) and continuing through to the operation and maintenance of generation facilities. This decision was based on the time and resources available under the scope of this project as well as Concentric's general observation that geography offers little competitive advantage for local companies to provide these upstream functions.

Through the above efforts, Concentric documented existing constraints and future supply chain challenges faced by the region in search of opportunities for the regional economy to have greater involvement in these supply chains. As further detailed in this report, Concentric has identified the following supply chain opportunities:

Summary of Opportunities

1. The supply chain for **onshore wind** is currently robust, but still offers a number of service-related opportunities to Atlantic Canada, including crane services for installations, operations and maintenance ("O&M"), and logistics services. Each of these services was noted in our interviews as being vulnerable to supply constraints. In addition, blade manufacturing, especially for smaller, community-scale projects, also provides an opportunity for industrial expansion.
2. Supply chain development for **offshore wind** and **tidal** power, has to-date been limited in the region due to the nascent state of these technologies. However, should these technologies reach commercialization, the resulting supply chains, which have much in common, will offer significant opportunities to the economies of Atlantic Canada. Local fabrication capacity can be employed to provide turbine substructures and assembly services at or near existing port facilities. Similarly, existing offshore oil & gas and marine service providers have the infrastructure and experience to become major contractors in marine renewable energy supply chains, offering deployment, installation, and O&M services. While current business opportunities to serve offshore wind and tidal power are very limited, Atlantic Canada is well positioned – in both geography and industrial infrastructure – to contribute substantially to these supply chains as they mature.
3. A healthy **biomass** supply chain is already established in Atlantic Canada, but opportunity exists to expand this supply chain. Increasing demand for biomass coupled with diminishing supplies of mill residue create the potential to make greater use of forest residue and low-grade timber, requiring expanded feedstock procurement equipment and service offerings. Thermal energy applications, especially exports, present the greatest opportunity for growth, but electric generation appears to offer less potential.
4. Potential supply chain opportunities also exist related to the development of **systems to power on- and off-grid applications** that displace diesel generation with renewable

resources. Local firms involved in wind/hydrogen demonstration projects may benefit from forming partnerships to develop a standardized control system that would allow for turnkey replication of these wind/hydrogen facilities. The off-grid use of biomass for district heating and/or cogeneration was also analyzed, and may offer further supply chain opportunities through greater application in district heating and remote communities.

Onshore Wind

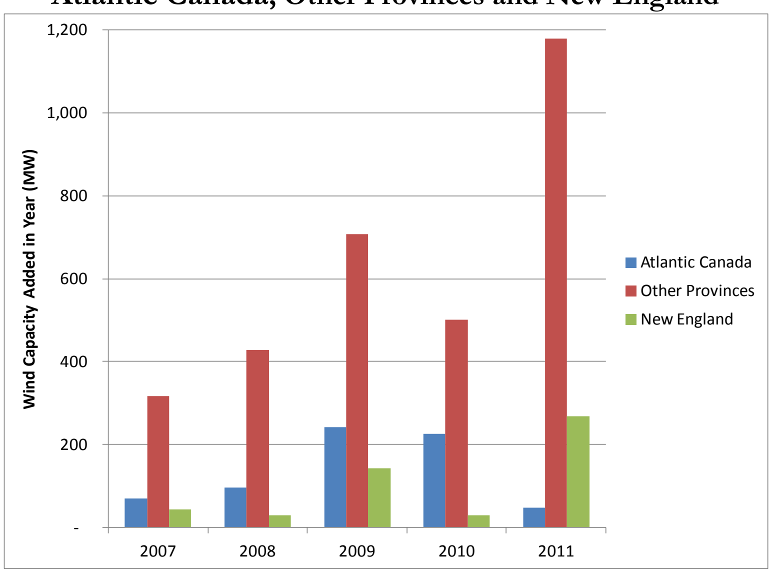
Overview

The supply chain for onshore wind in Atlantic Canada is robust. A strong chain of equipment and services suppliers has been developed to serve the substantial Feed-in-Tariff ("FIT") markets in Ontario and Quebec, along with U.S. states having to comply with Renewable Portfolio Standards ("RPS"). These markets are within economic transport distance to most locations in Atlantic Canada. Meanwhile, the pace of new wind project development in North America is expected to slow slightly in 2012 as a result of a weak economy and inconsistent policy. This may leave a slight overcapacity in the wind supply chain, especially for servicing Maritime markets.

Current Onshore Wind and Supply Chain Activity

Wind development in Atlantic Canada has historically been a strong contributor to overall Canadian wind development, and has outpaced development in New England. However, this was not the case in 2011, as policy drivers in New England, Ontario and Quebec were behind a significant increase in new wind capacity in that year.

Figure 1 – Annual Wind Capacity Additions, Atlantic Canada, Other Provinces and New England



Sources: CanWEA; SNLi.

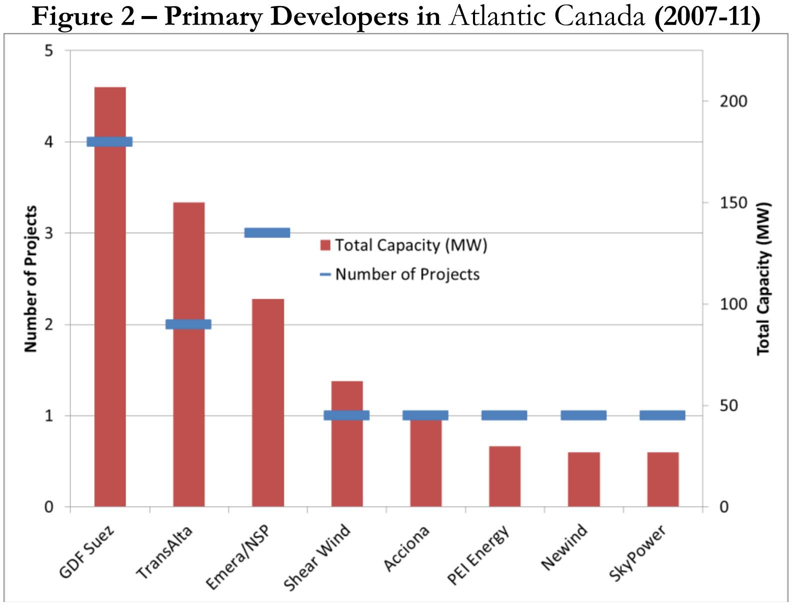
The surge in new wind capacity additions in Canada and New England has attracted a deep supply chain ready to serve new projects. This is particularly true in Ontario and Quebec, each of which has attracted new turbine manufacturing facilities in recent years. This growth is largely the result of the local content requirements embedded in their respective feed-in tariff programs. Concurrently, the recent relative decline in new wind capacity additions in Atlantic Canada coinciding with the economic downturn has meant that these few projects have been able to benefit not only from supply within the region, but also from strong sources of supply in eastern Canada and New England. Competition for supplies from eastern Canada and New England are expected to ramp back up as the regional economies are reinvigorated.

Key Industry Participants

The supply chain in the wind industry starts with the developer, which is typically responsible for selecting the original equipment manufacturer for the turbine (the "Turbine OEM"). The Turbine OEM then typically subcontracts for various turbine components.

As shown in the Figure below, the most active wind developers in Atlantic Canada over the past five years have been GDF Suez and TransAlta, which together have developed slightly more than one-half of the wind capacity in Atlantic Canada during that period. The remaining developers include a diverse group of smaller independents, utilities and municipalities. GDF Suez's projects have been primarily in New Brunswick and PEI, where it developed the Caribou and West Cape projects, respectively. TransAlta was responsible for the Kent Hills projects in New Brunswick. Recent Nova Scotia projects have been developed by Shear Wind and Nova Scotia Power ("NS Power"), along with a variety of other developers.

Figure 2 – Primary Developers in Atlantic Canada **(2007-11)**

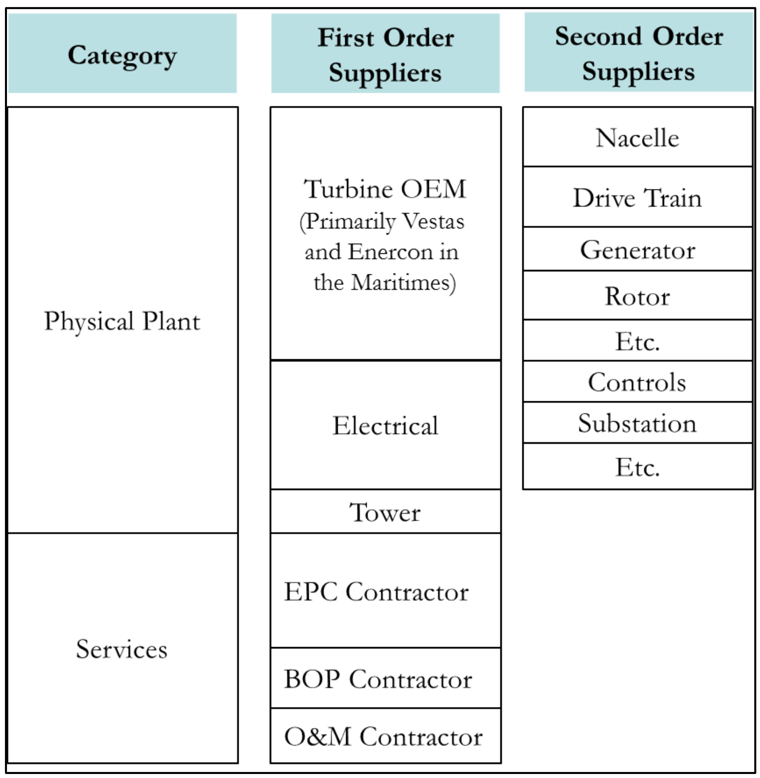


Source: CanWEA

Value Chain Components

First Order Suppliers: As noted above, the Turbine OEM is the first purchasing decision for a wind project developer. According to CanWEA, the turbine makes up approximately 70-75% of the total project cost, with engineering, site service and construction making up the balance.[1] Site electrical work and the steel tower structures may or may not be included in the Turbine OEM package. The EPC contractor typically works with the Turbine OEM in order to complete construction. Roads and foundations and electrical substation work is completed either by the EPC contractor or a subcontract. Commercial operating and maintenance services are also provided to owners that either do not have that capability in-house or to those who wish to alternatively deploy capital toward the development of subsequent projects. Together, these functions comprise the "First Order Suppliers" as shown in the Figure below.

Figure 3 – Onshore Wind Supply Chain Diagram

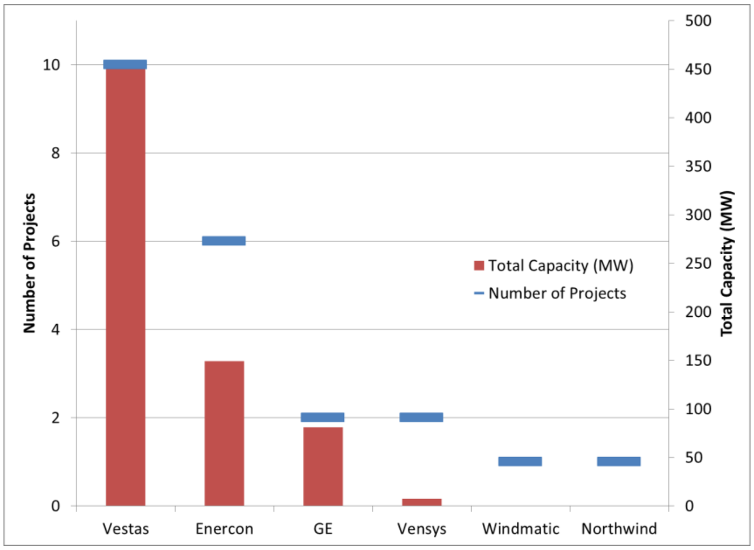


The Turbine OEM package includes the turbine, but may also include the blades and any or all of the "Second Order Suppliers" components listed above. For example, Enercon, a Germany-based Turbine OEM and leading supplier to wind projects in the region, can provide not only the turbine, but also the gearbox, electrical controls, the tower and the foundation. Enercon's plant in Matane, Quebec, which opened in June 2011, manufactures all of these components and/or assembles them from parts shipped from Germany, providing delivery with reasonable transport costs to points in Eastern Canada. Enercon has a unique concrete tower structure, which avoids the higher shipping cost of steel tower sections.

[1] CanWEA / CME Wind Industry Supply Chain, Opportunities for Canadian Manufacturers," Canadian Wind Energy Association, Canadian Manufacturers and Exporters, 2009, at 9.

As shown in the figure below, Vestas has been the most commonly used Turbine OEM in Atlantic Canada over the past five years, followed by Enercon and GE. Other Turbine OEMs are focused primarily on turbines designed for smaller-scale projects.

Figure 4 – Top Turbine OEMs for Atlantic Canada Projects (2007-11)



Source: CanWEA.

Second Order Suppliers: Like Enercon, most of the larger Turbine OEMs provide second-order components under a single contract, but local firms have found opportunities remaining. For example, for its 99 MW Caribou wind park in New Brunswick, developer GDF Suez hired Vestas to provide everything associated with the wind turbine, but Emera provided the collection system and substation, AV Cell in New Brunswick provided civil works, and the Halifax office of Stantec provided engineering. According to GDF, they did not hire an EPC contractor to oversee 2009 project construction, since few EPC alternatives were available. GDF indicates that alternatives such as Mortenson Construction, White Construction (U.S. firms) and Sunny Corners (New Brunswick) are all viable EPC alternatives they would consider if they were building those same projects today.

Many second-order components are also manufactured by others under subcontract. For example, Vestas, headquartered in Denmark but with manufacturing facilities in Colorado, can and does provide almost all first and second-order turbine supplies under a single Turbine OEM contract. However, Vestas will look to other companies for its gearbox needs, and occasionally for generators, castings and towers. This is particularly true when these bulkier components can be shipped from a manufacturing facility that is closer to the project than Vestas' Colorado facilities. Similarly, GE, which only has manufacturing capabilities for the turbine, electrical controls and gearbox, will always subcontract for the remaining second-order supplies.

Towers in particular have provided an opportunity for firms in Atlantic Canada to fulfill a supply chain need. In 2011, Daewoo, in partnership with the government of Nova Scotia, opened the DSME Trenton facility in order to build towers. Given its accessibility to rail and proximity to potential demand in eastern Canada and the US Northeast, DSME Trenton expected a significant opportunity to supply towers to these regions. A representative of Shear Wind confirmed that towers were indeed in short supply before the DSME facility was brought on line. Driven by supportive tax policy in the US, demand for towers was strong. At the time, the Marmen facility in Quebec was the only tower manufacturers in Eastern Canada. However, demand for towers in the last six months has been weaker than expected, due in part to expiring US tax credits and slowing installations in Atlantic Canada. Moreover, new tower makers, such as DMI (US-based) and CS Wind (Korea-based) have entered Eastern Canada to support the Ontario and Quebec feed-in tariffs. These factors have caused in a slowdown at DSME Trenton over the last six months.

Nonetheless, DSME Trenton representatives maintain a positive outlook for the company. The company just began to make 7-9-meter turbine blades, for use on community-scale projects, such as those being proposed under the Nova Scotia Community Feed-In Tariff ("COMFIT"). The company is separately considering the manufacture of larger blades in order to serve the larger turbines that are being used to create smaller wind farm footprints, as well as a nascent offshore wind market.

Effects of International Trends in the Onshore Wind Supply Chain

Several current trends in the international wind supply chain have the potential to affect the supply chain in Atlantic Canada, including increasing vertical integration of Turbine OEMs, and increasing specialization by turbine size. As noted above, all of the top Turbine OEM's serving Eastern Canada are foreign companies, including, Vestas (Denmark), Enercon (Germany), GE (U.S.), and Vensys (Germany), and each of these companies has increased its vertical integration in recent years. This influx of substantial foreign capital into wind turbine manufacturing is a potential barrier to the development of new independent local businesses serving under the Turbine OEM umbrella of suppliers, given the well-capitalized competition.

The size and configuration of wind turbines is evolving in the international market. The need for more efficient larger turbines on increasingly smaller sites has increased the need for larger blades, while a significant market for smaller community-scale blades is also increasing. LM Glasfiber (a Danish company, with manufacturing facilities in Quebec, has captured a significant share of the larger blade market in Canada, and is currently manufacturing a 61.5-meter blade to be used for 5 MW offshore applications in Europe. However, LM Glasfiber's smallest blade is 29.5-meters, which is designed for a 1.3 MW turbine.

A medium-scale (50-550 kW) blade market has also developed to serve remote locations and in response to renewable energy feed-in tariffs. Seaforth Energy, based in Dartmouth, Nova Scotia, has been successful in this medium-scale space marketing its 50 kW AOC 15/50 turbine in response to the COMFIT and similar international incentives. Seaforth manufactures its own blades in Nova Scotia and its control panels and drive train components are sourced from Halifax and Quebec respectively. The supplier base for small-scale blades (<50 kW) is decentralized, and demand is increasing due to the Nova Scotia COMFIT and to recent development of other community projects across the region.

Supply Chain Bottlenecks and Vulnerabilities

None of the developers or Turbine OEM's interviewed expressed any concern about their ability to source adequate supply for their projects. Nonetheless, as described below, several supply chain vulnerabilities became evident as a result of Concentric's research and interviews.

- Tower manufacturer DSME Trenton, which imports steel plate from Nucor Steel in the US, indicated that steel prices continue to increase due in part to high transportation costs. This could create vulnerability for tower production should the previous pace of turbine new-builds resume.
- At least two studies identify bearings, forgings and gearboxes as the second-order components that are generally the most vulnerable to supply chain disruption.[2] All of these components have significant technological barriers to entry and high technology risk, which have deterred many companies from entering these markets. Further, several players in these areas have been integrated into Turbine OEMs, such as Suzlon's 2006 acquisition of gearbox manufacturer Hansen. This creates a relatively small manufacturing base that is vulnerable to surges in demand.
- After reviewing the primary erector/construction providers of several Atlantic Canada projects, it became evident that the supply and expertise of crane and other tower assembly services was concentrated in a limited number of firms in the region.
- Given that there are few wind O&M service providers focused on the Canadian market, existing wind projects are potentially vulnerable to an inability to procure these services when their warranty contracts with Turbine OEM's expire. At least one study identified a concern that "renewal of such contracts will be prohibitively costly and that there will be a shortage of adequate economic service and maintenance providers within the country."[3]
- Finally, several interviewees expressed that some of their wind development projects experienced delays as a result of logistical difficulties and documentation requirements as various project components were being shipped across provincial and national borders.

[2] "Wind Turbines: Industry and Trade Summary," U.S. International Trade Commission, June 2009, at 9, and "Opportunities for Canadian Stakeholders in the North American Large Wind Turbine Supply Chain," Delphi Group and Garrad Hassan for Industry Canada, September 2007, at 24.

[3] Opportunities for Canadian Stakeholders, op. cit., at iii.

The interviewees indicated that the more significant delays were due to inter-provincial and international import requirements.

Potential Opportunities

Based on the above, Concentric sees the following potential opportunities for fulfilling onshore wind supply chain requirements in Atlantic Canada:

- **Blade manufacturing** – As noted above, there is an increasing need for smaller community-scale blades. While Seaforth does already serve this market, and DSME Trenton is in the process of entering the market, there may be room for other participants to take advantage of this growing opportunity.
- **Crane services** – Concentric's observation that many new projects in Atlantic Canada have turned to a small group of crane owners and operators – particularly in Nova Scotia – leads us to believe that construction firms with appropriate crane equipment may be able to move into the local wind project space.
- **O&M service providers for small projects** – Most Turbine OEMs will provide long-term service agreements with the sale of their turbines. Given the current slowdown in turbine sales, OEMs have recently been providing especially long agreements (10-years+) as a sales enticement. Also, some developer/owners will elect to self-maintain following contract expiration. Nonetheless, smaller projects that do not use the major Turbine OEMs, including projects bidding into the current COMFIT, many be candidate customers for O&M service agreements in coming years.
- **Logistical services** – As noted above, transportation of major components can be both a logistical and political challenge. There may be a niche service role for a firm familiar with logistics and importing in Atlantic Canada.

Offshore Wind

Overview

While Atlantic Canada has attractive offshore wind resources, the high development costs and local energy market dynamics have not provided adequate incentive for development to date. Electricity prices in Atlantic Canada vary by province but, in general, the region pays power prices that are considerably lower than the current cost of offshore wind. In a February 2011 study, the U.S. Department of Energy estimated the cost of offshore wind generation (exclusive of transmission and distribution costs) at 27 cents per kilowatt-hour.[4] This is approximately two times the average total cost of electricity in Atlantic Canada.[5] The region's backbone transmission grid is also fragmented and inadequate to accommodate the addition of offshore wind power at quantities that would justify development. Newfoundland and Labrador are not connected to the mainland transmission grid and have insufficient load to warrant offshore wind development on their own. This combination of market factors provides little economic basis for offshore wind development in Atlantic Canada.

Most of the provinces in Atlantic Canada have enacted renewable energy mandates creating a potential market for offshore wind; however, these renewable energy mandates are currently being fulfilled using lower cost renewable resources like onshore wind.

Setting aside for a moment the current economics of offshore wind, in terms of supply chain involvement, Atlantic Canada possesses industrial experience in a number of fields—from steel fabrication and shipbuilding, to marine services and engineering—that have the potential to add value to a local offshore wind supply chain. The proximity of the region to the northeastern U.S., where additional offshore wind developments are underway, also offers an opportunity to expand the market for these supply chain services beyond Atlantic Canada. Many barriers remain to offshore wind development in the region, but as market experience in Europe and elsewhere drives down costs, a number of supply chain opportunities may lie ahead for the region.

Current Offshore Wind and Supply Chain Activity

There are currently no offshore wind farms in North America. In Canada, Windstream Energy Inc. is developing the 300 MW Wolfe Island Shoals wind farm in Lake Ontario near Kingston, Ontario. Windstream was awarded a power purchase agreement with Ontario Power Generation through the province's feed-in tariff program in April 2010, but in February 2011, the Ontario provincial government imposed a moratorium on offshore wind developments. Ontario cited the need for

[4] U.S. Department of Energy, A National Offshore Wind Strategy: Creating an Offshore Wind Energy Industry in the United States, February 2011.

[5] Manitoba Hydro (Based on residential bills of 750 kWh per month).

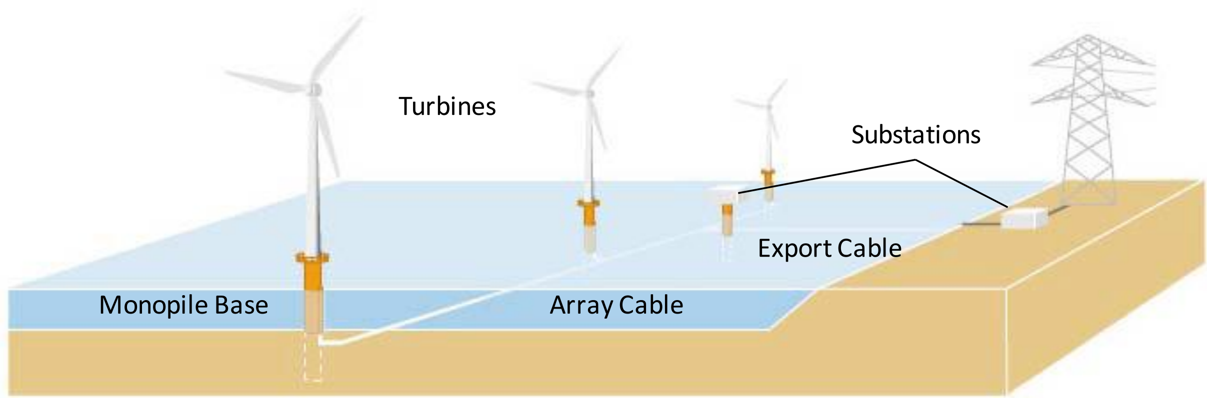
further scientific research, and the moratorium is still in effect. No offshore wind farms have been proposed to date in Atlantic Canada.

A number of offshore wind projects are under development in the U.S., with the majority occurring off the Atlantic coast. Of these projects, Cape Wind's planned 420 MW facility in Nantucket Sound off the southern coast of Massachusetts has advanced the farthest. Cape Wind has been approved for construction and operation and is currently searching for financing. A number of other Atlantic states are pursuing offshore wind projects in their jurisdictional waters and the federal government is working with Atlantic states to promote the development of offshore wind facilities on the Outer Continental Shelf.

Europe is currently the global leader in offshore wind development. Offshore wind facilities have been operational in Europe since 1991, and total installed capacity at the end of 2010 surpassed 2.9 GW. Offshore wind developments have progressed in Europe despite the high development costs and associated power prices largely due to the European Union's commitment to carbon dioxide reductions.

Value Chain Components

Figure 5 – Offshore Wind Supply Chain Diagram



Source: BWEA (adapted by Concentric)

While the mechanical and electric plant components of an offshore wind project are almost identical to those of an onshore wind installment, the offshore location of these arrays adds a number of components to the necessary supply chain. Offshore turbines are typically larger in scale than those for onshore installations making water transport the only feasible method of moving components. This has led to an increasing decoupling of the onshore and offshore wind supply chains. This section highlights the major components of the offshore wind value chain.

Turbines: The manufacture of offshore wind turbines is dominated by European firms like Siemens, Vestas and Repower that also have a major presence in the onshore turbine industry. As the industry matures, new turbine manufacturers are entering the market, bolstering supply and competition. Because offshore wind deployments have occurred almost exclusively in Europe, the manufacturing operations have thus far also been located in Europe. The wind turbine manufacturing supply chain is increasingly being characterized by vertical integration of subcomponents (generators, gearboxes, bearings, etc.) The technical requirements of turbine manufacturing make new entry into this market difficult; however, if an offshore wind industry develops in Atlantic Canada or the U.S. look for existing turbine manufacturers to open new plants in North America to feed these markets.

Substructures: The substructures for offshore wind turbines are not technically sophisticated, but account for a significant portion of the capital expenditures associated with a project. These factors make substructure manufacturing an attractive entry point for local businesses into the offshore wind supply chain. The fabrication of substructures requires a coastal manufacturing facility on a sizeable plot of land in order to provide lay-down yards for oversized components. Manufacturing related to an offshore wind supply chain would likely be located along the Atlantic Coast of Nova Scotia. Existing facilities along Nova Scotia's Atlantic coast have the fabrication skill and capacity to support the manufacturing of turbine bases and substructures for initial projects in the region. Full-scale commercial development would require strategic expansions of well-positioned yards.

Electrical Plant: The electric equipment required for an offshore wind facility—generators, converters, transformers, switchgear, etc.—is typically manufactured and delivered by global electrical engineering companies (Siemens, ABB, Alstom Grid, and General Electric). These firms are based mainly in Europe and North America, but have established manufacturing facilities across the globe. No supply shortages are anticipated in the market for electrical plant components, as a robust supply chain already exists to support the onshore electric distribution and transmission industry.

Cables: Subsea array cables are required to transmit the power from the offshore turbines either directly to an onshore substation or to an offshore substation where it is converted to a higher voltage and then transported via a high-voltage subsea transmission cable to an onshore connection to the electric grid. The manufacturing of subsea transmission cables is concentrated among a handful of European firms (Nexans, Prysmian, ABB) due to the growing offshore wind industry in that region. While these companies tend to have multi-national operations, the manufacture of subsea transmission cables tends to occur in a single location with the cables then shipped to the project site. Atlantic Canada does not possess the manufacturing capacity to produce subsea cable. With constrained manufacturing capacity and lead times of up to two years for subsea cable, there is the potential for this to become a bottleneck in the offshore wind supply chain.

The installation of subsea cable is typically handled by a separate entity. In Europe, offshore construction firms like Technip and Global Marine exist to do this work, but electric and telecommunication companies operating in Atlantic Canada may also have the expertise to handle cable-laying.

Vessels: A variety of vessels are required to construct an offshore wind array. Vessels are needed to haul components and transport personnel to the offshore site, to provide cranage and erection services, to lay and connect cables, and to retrieve and service equipment. Offshore wind deployments (i.e., erection) are predominantly conducted using dynamic positioning ("DP") vessels borrowed from other industries such as oil & gas. However, as the offshore wind industry has matured in Europe, an increasing number of project developers are constructing purpose-built vessels for their deployments. Few suitable DP vessels (Class 2 or 3) are available in Atlantic Canada and additional DP vessels based in the Gulf of Mexico or Europe would have to be employed for deployments in Atlantic Canada. The vessel requirements for offshore wind servicing and maintenance are less stringent and local marine service yards can repurpose or build vessels to serve this need. Nova Scotia-based, A.F. Theriault currently builds purpose-built vessels for offshore wind turbine servicing.

Port Facilities: The large size of offshore wind turbines dictates that component parts be transported by water. This market dynamic necessitates that the manufacturing and assembly of components occur at or very near port facilities. Experiences in Europe indicate that two types of port facilities will be required. Manufacturing ports, where the manufacturing facilities are located on the water to facilitate the transportation of completed components directly to the installation site or to a central mobilization point located close to the installation site. These mobilization ports, the second type of port facility, are used to receive and collect the components where they are then loaded onto installation vessels or other barges for transport to the installation site. The Marine Renewable Energy Infrastructure Assessment conducted by the Nova Scotia Department of Energy estimated that in order to support a construction base of 100 turbines per year, port facilities would have to offer eight hectares of lay-down area and 200-300 meters of quayside for assembly and deployment.[6] The same report notes that the collective capacity of the industrial ports on Nova Scotia's Atlantic coast should be capable of providing this capacity.

O&M: In order to provide operations and maintenance services for an offshore wind facility, additional supply chain components are required. An onshore facility in close proximity to the installation will be required for monitoring equipment and staff. Many of the same modified offshore oil & gas vessels will be required for major turbine repairs and cable retrieval, while less sophisticated classes of vessels or helicopters can be used for more minor repairs.

[6] Nova Scotia Department of Energy, Marine Renewable Energy Infrastructure Assessment, August 2011.

Effects of International Trends in the Offshore Wind Supply Chain

International supply chain developments, particularly in Europe, will be integral to the development of an offshore wind industry in Atlantic Canada. The maturing of the European offshore wind industry and the advancements along the learning curve that commercial experience in that region will provide offer the best opportunity to reduce the development costs of offshore wind. As the supply of offshore turbines proliferates, and marine service firms gain experience and streamline the deployment processes, development costs should come down. Such supply chain innovations in Europe—and perhaps along the U.S. Atlantic Coast—will be necessary precursors to an offshore wind industry in Atlantic Canada. In the meantime, opportunities may exist for port facilities and marine service firms in Atlantic Canada to become part of the supply chain for offshore wind projects off the U.S. Atlantic coast as well.

Supply Chain Bottlenecks and Vulnerabilities

Any discussion of potential bottlenecks or gaps in the offshore wind supply chain in Atlantic Canada must be largely theoretical as the region has yet to develop any offshore projects for such a supply chain to serve. That being said, much can be inferred from an analysis of the offshore wind industry's growth in Europe coupled with a survey of existing industry and services available in the region. Concentric identified the following supply chain vulnerabilities:

- Atlantic Canada has some capability to utilize local vessels currently dedicated to the marine and offshore oil & gas industries for many functions, but DP vessels will be necessary for deployments and erection. Such vessels and contractors are available in the Gulf of Mexico or from Europe, but they are expensive and availability may be limited. The local construction of purpose-built vessels is cost-prohibitive unless a robust offshore wind industry develops in the region.

- Shortages of most electrical infrastructure required are unlikely as a well-established supply chain for this equipment exists to serve the electrical transmission and distribution business. The exception here is the supply of subsea high voltage transmission cable. Limited supply chain capacity exists and is located almost exclusively in Europe. A recent study of the European offshore wind supply chain predicts that the European demand for high voltage subsea cable alone could result in supply shortages by 2015 without capacity expansions.[7] The lead time to bring new manufacturing capacity on-line is three to four years. The supply of subsea array cables is more diverse, with regional manufacturing available.

- Atlantic Canada currently has limited capacity to manufacture turbine subcomponents (DSTN's Trenton facility being an important exception). Turbines should not be in short supply, and if there is a strong market signal for offshore wind development in Atlantic

[7] European Wind Energy Association, Wind in our Sails: The coming of Europe's offshore wind energy industry, November 2011.

Canada foreign manufacturers will likely expand their operations to the region in order to exploit cost advantages. In the absence of a strong signal for offshore development in the region, foreign turbines should still be available, just at a higher price due to the cost of importation.

Potential Opportunities

The dynamics of an offshore wind supply chain offer a number of growth opportunities for the economies of Atlantic Canada. As noted in the previous section, and onshore wind supply chain already exists in Atlantic Canada, and the region is endowed with a wealth of marine-focused industrial capacity and experience. These existing industrial capabilities can also serve as the foundation for an offshore wind supply chain.

- **Fabrication and Port Facilities** - The large size of offshore turbine components requires coastal manufacturing facilities and necessitates transportation of components by water. These factors offer a considerable cost advantage for component manufacture and assembly at locations in the proximity of the installation site. Regional firms have an opportunity to leverage existing expertise in fabrication and marine services to play a significant role in the supply chain. Local manufacturing can construct substructures and locally-sourced jack-up barges can be used to assemble turbines at the port facility. Ports like Dartmouth/Halifax, Canso, and Sydney have the capacity to support such manufacturing. Local marine service firms can then be used to deploy turbines to the installation site as well as providing erection and repair services. The location of Atlantic Canada's existing port facilities and coastal manufacturing are also well-located for offshore wind deployments.

  Though currently stalled by the Ontario moratorium, the Wolf Island Shoals development in Ontario is a good example of the supply chain value that can be captured by local economies in the development of offshore wind. Bermingham Foundation Solutions will place the wind turbines in Lake Ontario, Walters Group will fabricate the substructures, and McKeil Marine will use its vessels to tow the turbines to the installation site and then will erect the turbines. All three of these companies are located in Hamilton, Ontario. Overall, Windstream Energy Inc. has been able to sign supply agreements with local firms to provide 60% of the content for its Wolf Island Shoals facility.

- **Major Contracting Services** - In Europe, there is a growing trend of regional offshore oil and gas firms emerging as major contractors as they gain more experience in the industry. The same opportunity exists for the transformation of local offshore oil & gas firms into EPC contractors. Atlantic Canada possesses a strong tradition of maritime industrial activity from shipbuilding, to offshore oil & gas, to salvage operations. These firms have an opportunity to leverage their existing infrastructure and experience to become contractors for the deployment and installation of offshore wind projects. Companies like JD Irving, with both shipbuilding and marine service divisions, have the capability to become major contractors in the offshore wind industry. These contracting opportunities for oil & gas and marine service firms are also not restricted to Atlantic Canada. If an offshore wind industry materializes in the U.S., these same firms would have an opportunity to provide contracting services to the entire Atlantic coast and the Great Lakes region as well.

Tidal

Overview

Due to the lack of commercial tidal installations, a dedicated supply chain has yet to emerge in the tidal industry. Demonstration project deployments to date have relied upon strategic partnerships between technology developers, electrical engineering firms, and local manufacturers and marine service firms. For example, Atlantis Resources has partnered with Lockheed Martin and JD Irving to test its AR 1000 turbine at an innovative tidal technology demonstration and testing center in Nova Scotia. This site, the Fundy Ocean Research Center for Energy ("FORCE"), is described in greater detail below.

In Atlantic Canada, Nova Scotia will continue to lead the way in the development of tidal power. A supportive policy environment has allowed for the establishment of the FORCE facility which has attracted tidal technology developers from across the globe. The future of tidal power in Atlantic Canada is now likely dependent upon the results of the FORCE demonstration projects and the industry's ability to reduce costs. Both Nova Scotia and New Brunswick have enacted renewable energy mandates, generating substantial appetites for renewable generation. Whether or not tidal energy plays a major role in meeting these mandates will depend upon its ability to compete economically with wind and other renewable resources.

If tidal developers are successful at deploying technologies capable of withstanding the harsh conditions of the Bay of Fundy and through their experiences can advance along the learning curve to bring down the costs of tidal power, commercial deployments are likely. Successful demonstration projects could also motivate other provinces like New Brunswick to pursue tidal power. New Brunswick also sits along the excellent tidal resources of the Bay of Fundy, and the port of Saint John—with its deep water, shipbuilding infrastructure and related industrial capacity—is well-suited for assembly and deployment.

Current Tidal and Supply Chain Activity

The tidal energy industry is at a very early stage of development. Canada has been one of the early-movers in this industry and, along with the United Kingdom ("UK"), is a leader in technology development. Other countries such as the United States and South Korea have also begun to pursue tidal energy developments.

In Atlantic Canada, FORCE, located in Nova Scotia in the Minas Passage area of the Bay of Fundy, is a four-berth utility-scale demonstration project that anticipates an installed capacity of 5 MW in the next two years. With financial backing from the federal government, the Province of Nova Scotia and private corporations, FORCE provides shared infrastructure for the trial deployment and operation of turbine technologies. NS Power has already deployed and tested an OpenHydro turbine at the FORCE site and is now considering its own tidal array in the Bay of Fundy. On a smaller scale (<500 kW), Fundy Tidal, Inc. is developing two distribution-connected tidal facilities in Nova Scotia.

Along with Canada, the United Kingdom has also taken the lead in tidal power development. The government-funded European Marine Energy Centre ("EMEC") in Orkney, Scotland serves the same function as the FORCE site in Canada. Its multi-berth tidal test site is connected to the UK grid by subsea cable and allows tidal developers to test their respective technologies. OpenHydro, Atlantis Resources, Hammerfest Strom and a number of other developers have deployed commercial-scale demonstration projects at the EMEC site. Marine Current Turbines has also deployed a 1.2 MW turbine in Northern Ireland and has plans to develop several larger projects. In the U.S., small-scale tidal demonstration projects are underway in select northeastern states. Earlier this year, Verdant Power received the first commercial tidal license issued in the U.S. to develop a 1 MW pilot project in New York City's East River.[8] Another developer, Ocean Renewable Power Company ("ORPC"), has received approval to install a 300 kW commercial tidal facility in Eastport, Maine at the mouth of the Bay of Fundy. ORPC's Eastport project employs a modular turbine technology and planned expansions will bring the eventual capacity to 3 MW.[9]

The off-takers of power from tidal facilities in Atlantic Canada would be the region's electric utilities. Nova Scotia Power, the privately-held electric utility in Nova Scotia would be the recipient of all power generated by the FORCE facility and any other commercial tidal projects in Nova Scotia. Should tidal power projects be developed in New Brunswick, the power from these facilities would be off-taken by New Brunswick Power, a Crown corporation.

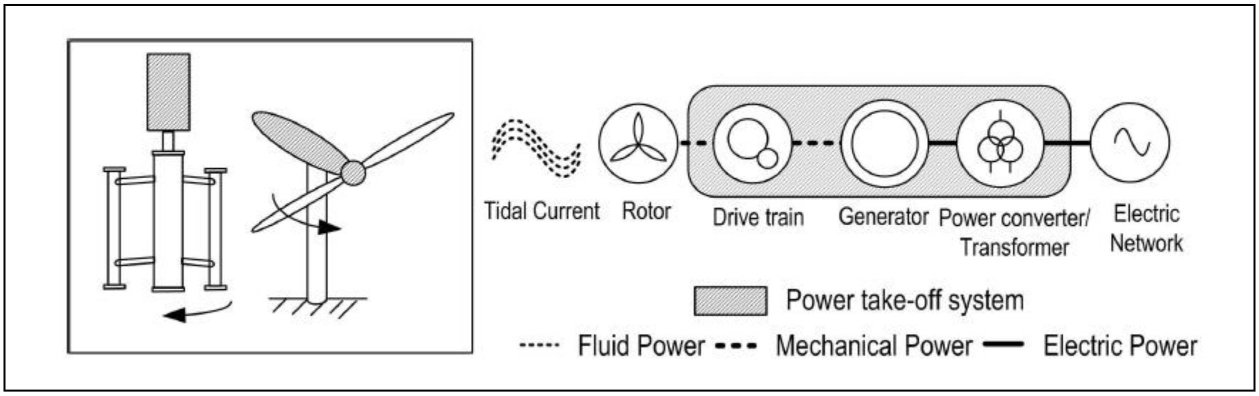
Value Chain Components

Tidal energy is still a nascent technology across the globe and, thus, the components and parameters of a dedicated supply chain are still being developed as different technologies are being pursued. Acknowledging this supply chain ambiguity, the section below presents a high-level overview of the essential supply chain components thought to be necessary to develop a tidal energy facility.

8 FERC News Release, "FERC Issues First Pilot License for Tidal Power Project in New York", January 23, 2012.

9 http://www.orpc.co/default.aspx

Figure 6 – Tidal Energy Supply Chain Diagram



Source: Canmet Energy, Evaluation of Electrical Technology Solutions in Marine Energy

Turbines: The mechanical plant consists of the turbines and supporting hydraulic systems that serve to harness the energy from tidal flows. None of the large-scale tidal turbines that have been or are being deployed in demonstration projects around the world are constructed in Atlantic Canada. Leading developers of large tidal turbines such as OpenHydro, Marine Current Technologies (Siemens), and Alstom have operations based in Ireland, the United Kingdom, and France respectively. In terms of small-scale tidal, the two facilities being developed by Fundy Tidal, Inc. in Nova Scotia will employ turbines from Calgary-based New Energy Corporation and Ocean Renewable Power Corp. based in Maine. At this point, however, the pre-commercial nature of the tidal industry means that commercial manufacture of turbines has not yet become entrenched in any country or region. Unlike the wind industry, tidal energy has seen little vertical integration in the manufacturing of turbine subcomponents to date. Many of these turbine subcomponents are made of steel and could be fabricated locally in Atlantic Canada to avoid the added cost of shipping components across the Atlantic.

Substructure: The substructures—consisting mostly of steel and concrete—that house the turbines and drive train can either be attached to the seabed via moorings or by piles/pins. The size and weight of these substructures dictate that they be manufactured at coastal facilities in the vicinity of the tidal installation. The demonstration projects carried out in Atlantic Canada have proven that regional companies have the necessary fabrication capacity and experience to manufacture these substructures. OpenHydro contracted with Cherubini Metal Works out of Dartmouth for its substructure. Fundy Tidal, Inc. relied on Clare Machine Works, also based in Nova Scotia, for its substructure. Other local manufacturers like JD Irving and DSME Trenton have the capacity to provide substructure fabrication and other manufacturing needs.

Electrical Plant: The electrical equipment requirements for a tidal facility—generators, converters, transformers, switchgear, etc.—are identical to those for an offshore wind project. These components are manufactured by the likes of Siemens, ABB, Alstom Grid, and General Electric. These firms are based mainly in Europe and North America, but have established manufacturing facilities across the globe. No supply shortages are anticipated in the market for electrical plant components, as a robust supply chain already exists to support the onshore electric distribution and transmission industry.

Cables: As with offshore wind, subsea array cables are required to transmit the power from the tidal generators to either an onshore substation or to an offshore substation where it is converted to a higher voltage and then transported via a higher voltage subsea transmission cable to an onshore connection to the electric grid. The manufacturing of subsea transmission cables is concentrated among a handful of European firms (Nexans, Prysmian, ABB). While these companies tend to have multi-national operations, the manufacture of subsea transmission cables tends to occur in a single location with the cables then shipped to the project site. Atlantic Canada does not currently possess the manufacturing capacity to produce subsea cable.

The installation of subsea cable is typically handled by a separate entity. In Europe, offshore construction firms like Technip and Global Marine exist to do this work, but local electric and telecommunication companies may also have the expertise to handle cable-laying. The subsea cables for the FORCE site were manufactured in Italy by Prysmian, but were installed by IT International Telecom Inc. out of their port facility in Halifax.

Vessels: Numerous vessels are required to deploy and install tidal arrays and also to conduct maintenance operations once the plant is in service. As the tidal industry is in the early stages of development, a number of strategies are being employed regarding vessel requirements. Some technology developers have undertaken the construction of vessels customized to their specific technology. OpenHydro commissioned the construction of the OpenHydro Installer, a twin-hulled, first-of-its-kind barge for its Scottish deployments. For its FORCE deployment, OpenHydro again contracted for the construction of a purpose-built barge with Halifax-based Atlantic Towing. Other developers have utilized crane barges and other vessels that typically support the offshore oil & gas industry. In addition, some European developers have access to dynamic positioning ("DP") vessels used to install offshore wind facilities, but the usage of DP vessels is seen to be prohibitively expensive for the tidal industry. For demonstration deployments, existing vessels capable of holding station in harsh currents can be borrowed from the offshore oil & gas industry, but a commercial tidal industry would require innovative new vessels designed to optimize efficiency during the workable portion of the tidal cycles.

Port Facilities: As is the case with offshore wind, the large size of tidal turbines dictates that component parts be transported by water. Economic efficiency necessitates that the manufacturing and assembly of components occurs at or very near port facilities. These port facilities will need to have significant manufacturing capacity, enabling developers to construct the substructure and possibly some turbine subcomponents in close proximity to the deployment site. There are currently few ports in the Bay of Fundy—Saint John, New Brunswick being the major exception—that meet these requirements.

O&M: Once operational, a tidal array will also require an operations and maintenance contractor. The O&M contractor will need monitoring equipment, an onshore control center in close proximity to the installation site as well as vessels to transport personnel, recover turbines, and cables, and to make repairs. Due to the tidal cycles in the Bay of Fundy, vessels employed for recoveries and repairs will have to be capable of completing their tasks within very short time windows. Existing monitoring equipment has performed poorly in the tumultuous conditions within the Bay of Fundy, and future equipment will have to be customized to local conditions.

Effects of International Trends in the Tidal Supply Chain

The tidal power industry is still in the demonstration phase and Atlantic Canada has been a leader when it comes to research and development, but similar efforts are afoot in Europe and the U.S. as well. If demonstration projects translate into commercialization in Europe or the U.S. before Atlantic Canada then these regions would have a leg up in establishing supply chain strength in turbine manufacturing and purpose-built vessel design and construction. Due to the more modest scale of global tidal resources compared to offshore wind, the industry may not support the manufacturing of such supply chain components in more than one location. In this sense, many of the tidal supply chain developments in Europe and the U.S. serve as competition to Atlantic Canada's supply chain interests.

Supply Chain Bottlenecks and Vulnerabilities

A dedicated supply chain for tidal power has yet to emerge as this technology remains in the demonstration phase. While existing manufacturers and service provides from other industries can be leveraged or repurposed to serve many of the industry's supply chain needs, certain key gaps in this supply chain are apparent.

- The location and configuration of existing fabrication capacity and port facilities in Atlantic Canada are inadequate to economically support commercial tidal power installations. The scale of tidal installations and the characteristics of tidal flows where the resources are strongest create the specific need for port facilities with fabrication capacity and a wet dock in close proximity to the installation site. The large size of tidal devices dictates that fully-assembled structures can only be transported to and from the installation site by water. The Marine Renewable Energy Infrastructure Assessment released by the Nova Scotia Department of Energy in August 2011 states that the high cost of such transportation necessitates the location of port facilities used for assembly and deployment within 150 km of the installation site.[10] This parameter greatly restricts the number of viable ports in the proximity of the Bay of Fundy. The majority of Atlantic Canada's coastal manufacturing and fabrication facilities are located in the Dartmouth-Halifax region of Nova Scotia or in Newfoundland. For its FORCE deployment, OpenHydro relied upon Cherubini Metal Works located in Dartmouth, NS. Cherubini assembled the device at its facility and then transported the device around the southwestern end of the province to the installation site. While the deployment from Cherubini's Dartmouth facility went smoothly, the transportation costs associated with towing components around the southern tip of Nova Scotia to the Bay of Fundy are prohibitive and the sea conditions in that area can be treacherous.

- The harsh conditions created by extreme tidal flows in the Bay of Fundy pose additional problems to tidal developers. Bay of Fundy tides cycle roughly every six hours with differentials ranging from 3.5 to 16 meters.[11] Traditional, floating platform vessels borrowed from the offshore oil & gas industry can hold station in the Bay of Fundy's currents, but they are expensive and they are also not designed for operation in the brief windows afforded by the tidal cycle. For a commercial tidal industry, purpose-built vessels designed to optimize functionality during these workable windows in the tidal cycle will be required.

- The limited manufacturing capacity of high voltage subsea cable also presents a potential vulnerability in the tidal energy supply chain. Few companies manufacture such cable, and Atlantic Canada currently does not have the capacity to manufacture subsea cable within the region. Growing demand from the offshore wind and oil & gas industries is already testing global supplies, with supply shortages predicted as soon as 2015. The lead time to expand the existing European manufacturing capacity of high-voltage subsea cable is estimated at three to four years.[12]

- Small-scale tidal developers face the additional obstacle of connecting their arrays to the region's electric grid. Whereas the utility-scale demonstration projects at the FORCE test site have benefitted from a connection to the region's transmission grid that was funded by the federal and Nova Scotia governments, smaller developers will bear the full cost of connecting their projects to the grid. Depending on the remoteness of potential installation sites, access to the grid may not be available at all.

[10] Nova Scotia Department of Energy, Marine Renewable Energy Infrastructure Assessment, August 2011.
[11] Nova Scotia Department of Energy, Marine Renewable Energy Infrastructure Assessment, August 2011.
[12] European Wind Energy Association, Wind in our Sails: The coming of Europe's offshore wind energy industry, November 2011.

Potential Opportunities

The tidal energy supply chain requirements are in many respects similar to those of the offshore wind industry. It should come as no surprise, then, that many of the opportunities for supply chain developments related to offshore wind also apply to tidal power.

- **Local Fabrication** - As with offshore wind, a large portion of the tidal value chain is related to the fabrication of array substructures. The construction of substructures, consisting mostly of steel and concrete, is not technically very challenging and there is local fabrication capacity to provide this function. The high costs associated with transporting components manufactured abroad to a local deployment site provide an added incentive for local industry to provide these fabrication services. Many of the subcomponents of tidal turbines are also made of steel and these too could be fabricated at local manufacturing facilities.

- **Major Contracting Services** - Local engineering and marine service firms will also be well placed to emerge as major contractors for tidal deployments and repairs. The local offshore oil & gas industry has vessels that can be used to deploy demonstration projects and decades of experience operating in the region's harsh maritime conditions.

- **Marine Technology & Services -** The lack of global supply chain developments to support the tidal industry also offers Atlantic Canada an opportunity to leverage its existing expertise in engineering, shipbuilding, and marine services to become a global leader in providing marine services for the tidal industry. Demonstration projects will have to cope with the harsh maritime conditions in the region and the dramatic tidal cycles experienced in the Bay of Fundy. If technologies and services developed to overcome these harsh conditions can be developed, there is a global opportunity to market this expertise for use in tidal installations across the globe. Unlike with offshore wind, where such technologies and services are already being developed to serve the European market, Atlantic Canada still has the opportunity to be a first-mover with tidal power.

- **National Shipbuilding Procurement Strategy** - Canada's National Shipbuilding Procurement Strategy ("NSPS") offers another valuable opportunity for the establishment of a tidal supply chain in Atlantic Canada. The combat contract portion of the NSPS was awarded to JD Irving in 2011. Under this contract, JD Irving will provide all defense-related large ship construction—21 vessels over a 20-30 year period—at its shipyards throughout Atlantic Canada. The NSPS combat contract will revitalize shipbuilding in the region while also providing an economic boost to related industries such as steel fabrication and manufacturing. The enhanced fabrication and manufacturing capacity located at or near major port facilities can also better enable the region to capture value in the tidal (and offshore wind) supply chain. The Industrial and Regional Benefits ("IRB") policy that applies to the NSPS combat contract, which requires all prime contractors to pursue business activities within Canada equal to 100% of the contract value, will provide an incentive for global manufacturers involved in the shipbuilding contract to utilize local contractors and supply chain capacity. The supply chain relationships that local contractors form with major international firms have the potential to offer residual benefits in the form of further collaboration on tidal deployments. Many of the major international manufacturers that will be attracted to Atlantic Canada by the NSPS (i.e., Rolls Royce and Lockheed Martin) have experience and skills that would translate well to the offshore wind industry. In cases where NSPS contracted work is undertaken outside of Canada, there may also be opportunities for the offshore wind industry to be the benefactor of IRB provisions requiring these large contractors to make commensurate investments in Canada.

Biomass

Overview

Biomass used for electricity generation can come from a number of sources—wood waste, municipal waste, etc.—but for the purposes of this study, we have focused exclusively on woody biomass. Woody biomass is currently the most abundant type of biomass available in Atlantic Canada, and is already being used to generate power with supply chains in place. All further references to "biomass" in this report refer to woody biomass.

Like onshore wind, the biomass industry in Atlantic Canada is well-established. In addition to being used as a feedstock for electricity generation, biomass is burned throughout the region by residential and small commercial and industrial customers to generate heat and is also now being exported to Europe for co-firing in fossil fuel plants.

In Atlantic Canada, biomass is a byproduct rather than a primary resource. In the current market environment, the supply of biomass is dictated by activity levels in the forestry and mill industries. These industries have contracted in the past several years due to the global economic downturn, but as the U.S. and Canadian economies recover activity in these industries should rebound creating a greater supply of readily-available biomass feedstock.

Based on the current demand for biomass, the industry has been able to obtain most of the necessary feedstock from mill residue, with forest residue used to supplement feedstock supplies when required. The availability of mill residue at the site of co-generation facilities makes it the least cost and most attractive form of biomass feedstock. The development trends in the region's biomass industry will largely be determined by the relative growth of demand for biomass and forestry/mill production. If production from the timber industry and from saw, pulp and paper mills outpaces growth in biomass demand for co-generation and pelletization then mill residue will likely be able to continue to serve as the dominant biomass feedstock.

On the other hand, if the demand for wood pellets and biomass-fired electric generation outpace production growth from forestry and mill operations, the industry will be forced to obtain a greater percentage of its feedstock from forest residue. This would present the biomass supply chain with both challenges and opportunities. Forest biomass is more expensive than mill residue as it must be collected from the forest and transported to the combustion site. However, if these higher costs can be overcome, the utilization of forest biomass could greatly expand the market and thus supply chain opportunities for biomass.

Current Biomass and Supply Chain Activity

The most common application of biomass for electricity generation is co-generation; in which biomass is burned to produce both electric and thermal energy. In Europe, biomass is commonly co-fired with fossil fuels in power plants to reduce greenhouse gas emissions. Scandinavian countries generate a large portion of their electricity from biomass and have been innovators in the development of a supply chain to provide biomass feedstock. Biomass is also being used, to a limited degree, to generate electricity in the U.S. in compliance with state renewable energy standards.

Atlantic Canada has only recently begun to utilize its biomass resources to generate renewable electricity, but a fully-developed supply chain for the procurement of biomass already exists to support the region's long history of using biomass to produce thermal energy. The added component of feedstock procurement inherent to the biomass supply chain creates a number of opportunities for the region's industry and labor force. While largely outside the scope of this report, the pelletization of biomass for usage in thermal energy systems, both domestically and abroad, requires additional processing that offers further supply chain opportunities.

The biomass supply chain is fully developed, but the scale of this supply chain in the region has been limited by economic and political factors. Biomass in the region has, to date, been a byproduct of the timber industry. Saw, pulp and paper mills produce residue (sawdust, bark, waste wood) that can be chipped for combustion. Forest harvesting also leaves residue (tops, branches, low-grade timber) that can be used as a biomass feedstock. The dependence of biomass on the timber industry has restricted its development to the provinces with active forestry industries—namely New Brunswick and Nova Scotia.

While the woodlands in these two provinces offer ample supplies of forest residue and low-grade timber biomass, both New Brunswick and Nova Scotia have implemented policies capping the amount of forest biomass that can be harvested annually to ensure sustainable forestry management. In 2008, New Brunswick announced a Biomass Policy, under which up to one million dry tonnes of forest harvest residues would be made available for bioenergy projects.[13] Nova Scotia's Renewable Electricity Plan, released in 2010, established annual caps on the harvesting of forest biomass for new electric generation (500,000 dry tonnes) and thermal co-generation (150,000 dry tonnes).[14] Nova Scotia subsequently released a Natural Resource Strategy in 2011 that reduced the cap on biomass for renewable electricity generation to 350,000 dry tonnes per year.[15]

In New Brunswick, Crown-owned New Brunswick Power, ("NB Power") currently does not use biomass as a feedstock in any of its own generation facilities; however, it does purchase electricity generated from several biomass co-generation facilities located in the province. AV Group, Group Savoie, JD Irving, and Twin River Papers all utilize biomass cogeneration at their industrial

[13] Climate Change Solutions, Canada Report on Bioenergy 2010, September 2010.
[14] Nova Scotia Department of Energy, Renewable Electricity Plan, April 2010.
[15] Nova Scotia Department of Natural Resources, The Path We Share, A Natural Resources Strategy for Nova Scotia 2011-2020, August 2011.

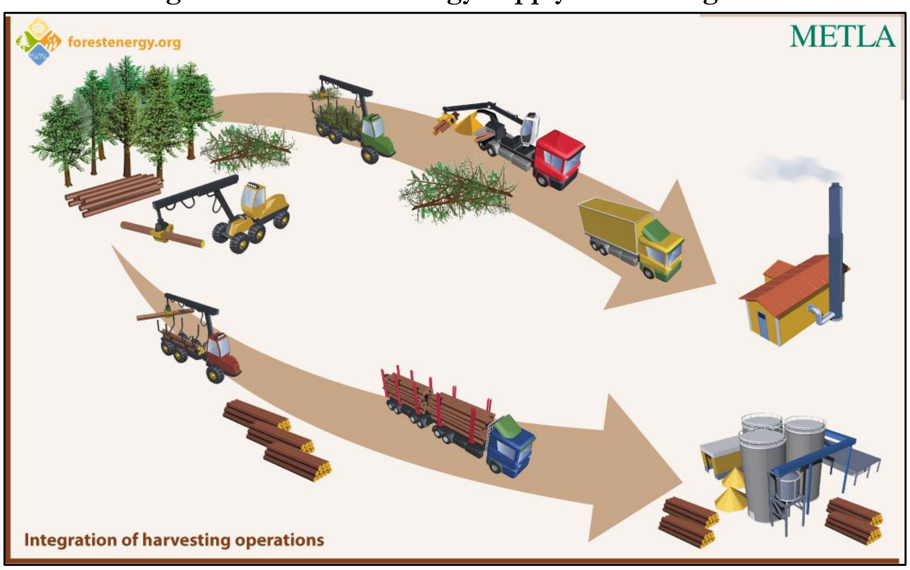
facilities. In Nova Scotia, privately-held NS Power currently uses biomass as a feedstock in its 22 MW Brooklyn co-generation plant and is developing a 60 MW facility at the site of the former NewPage paper mill in Port Hawkesbury. Northern Pulp Corporation also operates a 23 MW cogeneration facility at a pulp mill to meet its electricity needs and can sell its excess power to NS Power.

Developers of biomass plants in New Brunswick and Nova Scotia are typically existing mills looking to optimize their facilities' operations. NB Power and NS power are the off-takers of all electricity generated by these biomass projects in New Brunswick and Nova Scotia respectively.

Value Chain Components

The supply chain for biomass is distinct from the other technologies covered in this report in that it still requires a feedstock (i.e., wood). Unlike the value chains for wind or tidal energy, where manufacturing and installation costs dominate, the biomass value chain is focused in large part on the procurement of this feedstock.

Figure 7 – Biomass Energy Supply Chain Diagram



Source: Forestenergy.org

The biomass supply chain begins with the feedstock. The three basic types of feedstock are: 1) mill residue, 2) forest residue, and 3) low-grade timber. The procurement of biomass feedstock consists of a number of functions, each requiring specific equipment. In some cases, all of the procurement services are provided by a single contractor, while in others these functions are divided amongst multiple contractors. The procurement supply chain also varies with the nature of the feedstock. Mill residue is conveniently located at the mill site where co-generation occurs and must only be chipped. The procurement of forest residue and low-grade timber, on the other hand, requires an expanded supply chain to harvest and collect the biomass before it is chipped and then to transport it to the combustion facility. The general functions involved in the procurement of biomass feedstock are detailed below.

Timber Harvesting: The majority of the biomass in Atlantic Canada originated in the region's forests, and the first step in procuring this resource is the harvesting of the timber. Mill and forest residue are both byproducts of the timber industry so in these cases the timber harvesting function falls outside the biomass supply chain. Low-grade timber stands are not of any interest to the timber industry though, so the supply chain to derive biomass from this resource would require harvesting. Biomass from low-grade timber stands offers additional opportunity for existing timber and land-clearing contractors in the region to provide this service.

Collection/Forwarding: While mill residue is conveniently gathered and available at mill sites, forest residue must be collected from scattered and often remote forestry sites. Forest residue requires additional equipment to forward and pile the feedstock at the roadside. The forwarders used to collect forest residue are customized equipment typically sources from Europe or elsewhere in North America, but local distributors (e.g., ALPA Equipment, Atlantic Cat) sell and provide parts for major brands such as Ponsse and Rottne.

Chipping/Grinding: Once the woody feedstock has been collected, it must be chipped or ground into wood chips for combustion. This process, known as comminution, can be achieved using either a chipper or a grinder. Chippers and grinders come in various forms. For forest residue, they can be mounted on forwarding equipment to chip or grind the biomass as it's collected, or mobile chippers/grinders can be delivered to the roadside residue piles for roadside chipping. For mill residue, stationary chippers or grinders can be located either at the mill site or at the biomass plant where it will be combusted. Chippers and grinders, like forwarders, are also typically ordered from European and North American manufacturers via the same regional distributors.

Transportation: Mill residue has the advantage of being located at the site of combustion. Forest residue, on the other hand, must be transported (typically as wood chips) to the biomass plant where they are combusted to generate electricity. Wood chips are transported using trucks, and these trucks can be owned by the same contractors that provide the forwarding and chipping services or by separate contractors. Alternatively, mill and forest residue can be transported whole and chipped or ground at the biomass plant, but this process is more costly due to the higher moisture content of the whole wood forest residue.

Transportation of the chipped feedstock to biomass plants is the costliest aspect of biomass procurement. Transportation costs account for a substantial portion of supply chain costs due to the scattered nature of forestry and mill sites as well as the additional weight of cargoes from the moisture content of wood in chip form. According to a 2007 report by Climate Change Solutions, the economic distance that forest residue can be transported is generally considered to be about 150 km, and escalating oil prices threaten to narrow this range even further.[16]

Combustion: Once the biomass has been procured it is delivered to a power plant where it is combusted—either on its own or co-fired with natural gas—to generate power. These biomass plants require technological components—steam turbines, generators, boilers, and condensers—that must be customized for biomass combustion. Many of these components are sourced from Europe and Asia, but some North American manufacturing is available as well. Biomass plants will also require a standard kit of electrical equipment—transformers, switch gear, etc.—to connect the plant to the electric grid. As with the other technologies covered in this study, electrical equipment is typically provided by global electric engineering firms based in Europe and the U.S., most of whom have North American manufacturing capacity.

The construction of these biomass facilities is typically overseen by international EPC contractors such as AMEC. Other local contractors are often also employed in the construction of such plants. The O&M function is either conducted in-house if the plant is owned by an electric utility, or can be contracted out for independently-owned cogeneration plants.

Effects of International Trends in the Biomass Supply Chain

There are some encouraging international supply chain developments that could greatly benefit the biomass industry in Atlantic Canada. Whereas the local usage of forest biomass is a fairly recent concept, the biomass industry in Scandinavia has been utilizing forest residue for decades. Through this experience with forest biomass supply chains, Scandinavian countries have had considerable success at reducing the cost involved in the procurement of this feedstock. In Sweden, costs related to forest biomass procurement fell 2% annually between 1983 and 2003 due to continuous supply chain innovation.[17] In Finland, early supply chain experiments with bundling—where whole energy wood is bundled for transport and then chipped at the end-use site—have the potential to reduce overall costs in the forest biomass supply chain. Such innovations in the forest biomass supply chain could be imported to Atlantic Canada where, if employed, they could reduce the cost of forest biomass and thereby greatly expand the supply of economical biomass feedstock.

The growing demand in Europe for Canadian-sourced wood pellets offers potential opportunities to the Atlantic Canada biomass supply chain as well. While the pellets burned in residential systems for thermal energy throughout Atlantic Canada require a higher-grade feedstock—typically sourced from certain types of mill residue—the pellets being exported to Europe to be co-fired in coal plants have lower quality standards. To meet this growing demand for exportable pellets, forest residue is increasingly being employed as a feedstock. The incentive pricing for Canadian wood

[16] Climate Change Solutions, Canada – Sustainable Forest Biomass Supply Chains, October 19, 2007.
[17] Climate Change Solutions, Canada – Sustainable Forest Biomass Supply Chains, October 19, 2007.

pellets is currently supporting the higher costs associated with harvesting forest residue where most Atlantic Canadian biomass markets currently do not. The supply chain development required to procure forest biomass for pelletization is equally applicable to forest biomass procurement for electric generation. If European incentives continue, innovations in forest biomass procurement for pellet exports could reduce the cost of forest biomass feedstock which would create the opportunity for expansion of the biomass supply chain.

Supply Chain Bottlenecks and Vulnerabilities

The largest supply chain constraint faced by the biomass industry is the potential shortage of mill residue as a low-cost feedstock. The supply of mill residue is entirely dependent upon the production of the saw, pulp and paper mills in the region. The global economic downturn has forced a number of the mills in Atlantic Canada to close their doors. While much of the saw mill production is expected to recover once economic climates improve, the pulp and paper industry was contracting even before the economic downturn. The difficulties faced by the saw, pulp and paper industries has reduced the supply of mill residue for use in biomass combustion plants. At the same time that mill activity has contracted, the overall demand for biomass has increased.

Many of the provinces in Atlantic Canada have implemented policies calling for a greater percentage of electric generation to come from renewable resources. This has, in turn, led to a greater interest in biomass combustion for power generation. Nova Scotia and New Brunswick have recently constructed a number of large-scale biomass cogeneration plants that have substantially increased the demand for biomass feedstock. The demand for wood pellets—which similarly rely upon mill residue as a feedstock—has also increased, creating further competition for the remaining supply of mill residue. In addition to the residential and small-scale commercial and industrial combustion of wood pellets to produce heat, European incentives for the co-firing of wood pellets in coal plants have also led to increased pellet production for export.

With insufficient supplies of mill residue, the industry must to look to forest residue to provide supplemental feedstock, and the recovery of forest residue requires additional supply chain components to forward the biomass to the roadside for chipping and to transport the chipped wood to the combustion plants. Conversations with industry participants did not reveal any pressing supply chain concerns. While most of the equipment required to procure forest residue are not manufactured in Atlantic Canada, local distributors sell all of the necessary equipment and parts and offer repair services.

Potential Opportunities

The opportunity exists for the expansion of existing biomass feedstock supplies through increased harvesting of forest residue and low-grade timber. Any such expansions will have to be weighed against concerns over forest sustainability, but would offer significant growth potential to the biomass supply chain.

- **Procurement Equipment Manufacturing** – The limited scale of the current forest biomass supply chain in Atlantic Canada has not warranted the local manufacture of the equipment needed to procure forest biomass. Atlantic Canada has significant untapped forest biomass resources, and should the provincial governments decide to harvest these resources in greater quantities there would be an opportunity for local manufacturers to enter the supply chain to provide such equipment. This scenario would likely also see existing equipment manufacturers from Europe and elsewhere in North America looking to expand into the region.

- **Forestry Contractors** – The expansion of biomass resources harvested in Atlantic Canada to include more forest residue and low-grade timber would require a more robust supply chain. The existing capacity of contractors providing forest biomass feedstock is currently rather modest due to low levels of demand and would have to be expanded. Biomass from low-grade timber would also require additional harvesting capacity. With the heavy equipment needs of such contracting operations and the high cost of transporting such equipment, locally-based contractors would have an advantage in this space.

- **Logistics** – Transportation costs account for a substantial portion of the forest biomass supply chain and, to date, have limited the usage of this resource. There is an opportunity for regional firms with expertise in logistics to apply their knowledge to the biomass industry. Should these efforts result in reductions to the cost of procuring forest biomass, they could also serve to greatly expand the quantity of cost-effective biomass feedstock.

Systems to Power Remote On- and Off-Grid Applications

This section of the report focuses on technologies that could be used to provide heat and/or power to remote communities in Canada in order to displace the current typical practice of running diesel-powered generators for power and burning heating oil for heat. Two such technologies have been designed with these functions in mind. The first technology, wind/hydrogen systems, has been tested on sites in Newfoundland and PEI. The Newfoundland site is in full-time use. The second technology, biomass for remote district heating, is commonly used in institutional settings such as universities and hospitals, but has not yet been adopted extensively by remote communities due primarily to its high up-front capital costs. The sections below provide a discussion of supply chain issues with respect to both of these technologies.

1) Wind/Hydrogen Systems

A wind/hydrogen system is a system designed to supplement or displace existing power sources in either on-grid or off-grid applications. The core of the system connects wind turbines to an electrolyzer, which pass the wind-generated electricity through water to split it into hydrogen and oxygen. The hydrogen can then be stored and used later to generate electricity using an internal combustion engine. Because it is able to store energy produced when the wind blows and generate power when it does not, the system solves the problem of intermittent generation that is inherent in a wind-only system. Intermittent generation from wind power is problematic since it requires an alternative source to come on line in order to serve load and balance the system when the wind is not blowing. Also, the constant ramping up and down of the alternative generator can cause excessive wear on that system. Intermittency is particularly acute in smaller off-grid systems, where a diversity of alternative generation sources is either lacking or non-existent. The wind/hydrogen system solves these problems by producing a relatively constant stream of firm energy.

There are at least ten wind/hydrogen systems in the world. Most of these systems are demonstration projects designed to showcase the capability of generating hydrogen for industrial uses. There are approximately six wind/hydrogen projects around the world that use the hydrogen to generate electricity at the plant level for on- or off-grid applications, approximately four of which are in continuous use by remote off-grid communities. Atlantic Canada hosts two such wind/hydrogen facilities, in Newfoundland and Prince Edward Island. Other wind/hydrogen plants are configured to produce hydrogen for transportation.

There are a variety of alternatives to using hydrogen as a storage medium, such as using compressed air, pumped hydro or batteries. For example, a demonstration project on a First Nations settlement in Saskatchewan is using battery storage in conjunction with an 800kW wind turbine, and is expected to come on line in the summer of 2012.[18] However, the most likely opportunity for Atlantic Canada to develop a wind/storage system for remote communities would be to replicate the wind/hydrogen systems in Newfoundland and PEI using the experience gained by developing and testing those systems.

The first wind/hydrogen system in the region was developed at the Wind Energy Institute of Canada at the North Cape testing facility in PEI. The project, developed by the PEI Energy Corporation and Frontier Power Systems, began with PEI Energy Corporation's installation of 5.3 MW of wind power in 2001 at the Atlantic Wind Test Site, which had been in operation since 1978. Wind power at the site was expanded to 10.6 MW in 2003. Federal and provincial funding to promote hydrogen production led to the idea to combine this existing wind production with hydrogen generation as a grid-connected system, but a cutback in federal funding led to plans for a more modest demonstration project.

Project developers also recognized that this small prototypical system would be relatively inefficient. Therefore, while energy from the 10.6 MW grid-connected North Cape wind facilities is sold into the PEI grid, the wind/hydrogen project was held to just 150 kW and is run intermittently for demonstration and testing purposes. PEI Energy indicates that, while a scaled project would be more efficient, high project levelized costs would still require that retail prices in the host community would need to exceed approximately $1.00/kWh in order to reach commercial viability.

Meanwhile, a second wind/hydrogen project was being developed on the off-grid community on the Island of Ramea, in Newfoundland, and was completed in 2011. Energy from this 400 kW project, which is owned by developer Frontier Power Systems, sells its energy to Nalcor under a PPA. This project is more efficient than the PEI project largely due to knowledge gained from completing that first system.

Value Chain Components

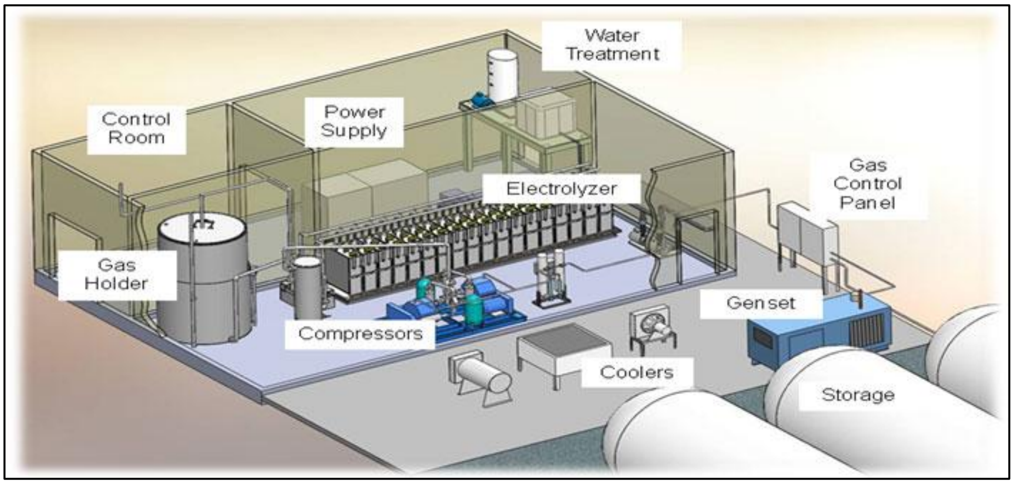
The primary components of a wind/hydrogen system are:

- a wind turbine/generator, and tower
- an electrolyzer
- a hydrogen compressor and storage tanks,
- a hydrogen-powered electricity generator or fuel cell ("Genset"), and
- a series of electronic controls to maintain the proper balance of wind generation, hydrogen production, hydrogen generation and diesel generation (or other alternative).

[18] "Cowessess Wind Turbine Battery Storage Project Gets a Boost," Blog Post, McNair Business Development, Inc., available at http://blog.mcnair.ca/2011/03/cowessess-wind-turbine-battery-storage.html.

The Figure below illustrates the typical configuration of these components:

Figure 8 – Primary Components Layout of a Wind/Hydrogen System



Source: PEI Energy Corporation.

In order to keep costs reasonably competitive, the turbines for both the PEI and Ramea projects are Daewoo models purchased from decommissioned California projects and reconditioned for the installation sites. Frontier Power Systems indicates that turbines for future projects would be sourced in the same way if they are available. Used turbine availability may become constrained if many more wind/hydrogen projects were developed. Further, the COMFIT may place additional demand for turbines of this approximate size, which are designed for community-scale projects. New community-scale turbines are readily available from companies such as Atlantic Orient (Nova Scotia-based) or Northern Power Systems (Vermont-based). Given their relatively small size, community-scale turbines can also be purchased from more distant manufacturing facilities than utility scale turbines.

Towers are also readily available from companies like Enercon, DSME Trenton and others, but they can be expensive for remote applications of any size given that high transport costs can be spread over only a few units. However, companies such as Acciona have begun to produce concrete towers on-site in order to reduce transport costs. While the Acciona application is designed specifically for very large towers to accommodate growing turbine sizes, it would also be beneficial where transport distances are relatively long. Frontier Power Systems is investigating the use of on-site concrete towers for new potential remote applications in Alaska, the NW Territories and the Yukon.

An electrolyzer, which uses electricity to split water molecules into hydrogen and oxygen, is a common piece of industrial equipment available from companies such as Hydrogenics, Teledyne, Proton and Norsk Hydro. This equipment is typically used for on-site generation of hydrogen and/or oxygen for various purposes such as power plant cooling, and military or aerospace applications. To save cost, the PEI project purchased a used Hydrogenics unit and refurbished it. The PEI unit is a standard efficiency unipolar type. The Ramea unit is higher efficiency bi-polar. The newest type, proton exchange membrane ("PEM") electrolyzers are the most efficient, scalable and responsive, but remain costly.

Compressors and tanks are also standard industrial equipment used for compressing and storing gasses of any type. The primary decision point for off-grid projects in this regard is whether hydrogen will be produced for vehicular use, as is done with PEI. Vehicular hydrogen must be compressed to very high pressures, requiring a larger compressor and tanks capable of handling these pressures.

Gensets can be either standard diesel engines, modified to accept hydrogen, or fuel cells, which convert hydrogen and oxygen to electricity without combustion. The Gensets for the PEI and Ramea projects are modified diesels. This set-up allows for fuel flexibility and use of technology already installed in remote locations, but it does require a retrofit in each new application, limiting scalability. Alternatively, a remote community in Bella Coola, BC has elected to use a fuel cell as the Genset for its hydro-hydrogen system. A fuel cell, also commonly procured from companies such as Ballard Power Systems or Plug Power (U.S.-based companies), has higher up-front costs but is more efficient than a converted diesel engine.

While all of the above components are used in existing industrial applications and are therefore generally available for purchase, the control systems that regulate a wind/hydrogen system are unique to this application. In each of the PEI and Ramea projects, the control technologies were engineered and built specifically for each project. Moreover, lessons learned from PEI are now integrated into the Ramea system. This capability, now resident in personnel at Frontier Power Systems, Nalcor and PEI Energy, may be an asset capable of replication in other settings, and could form the basis for a new design manufacturing capability in Atlantic Canada if wind/hydro systems were to proliferate.

Bottlenecks and Opportunities

As discussed above, the only piece of the physical supply chain for systems to power remote communities that appears to be lacking is the ability to procure a standardized control system that integrates the wind, hydrogen generation and Genset systems. This lack of a single affordable control system will remain until the number of new wind/hydro installations is great enough to allow for standardization within a single manufacturing entity. Therefore, development of a standardized control system to allow turnkey replication of the system in multiple communities is a niche opportunity. Given the experience recently accrued by PEI, Nalcor and Frontier Power Systems, any new enterprise would be advantaged by forming a partnership with one or more of those entities.

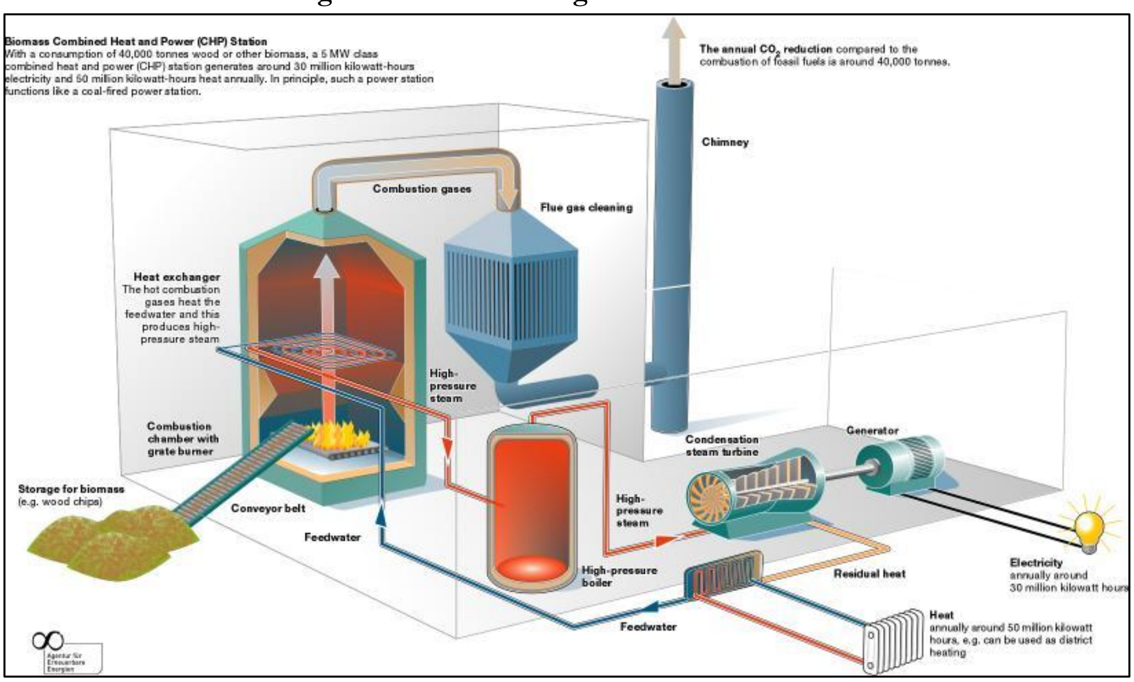
Policy drivers and human factors will be critical factors in the future success of these systems. Currently, the cost of wind/hydro systems significantly exceeds the cost of incumbent diesel generation, so policy support will be required in order to make development of these systems to be economic. In addition, given the complexity of wind/hydro systems relative to existing diesel, adoption of the new hydro systems will require the commitment of any adopting community to train and dedicate staff to operate and maintain the system in potentially remote locations and adverse environmental conditions.

2) Biomass for Remote District Heating

One additional consideration for displacing diesel in remote locations is to employ biomass fueled district heating and/or cogeneration. Compact Appliances (New Brunswick), in partnership with biomass pelletizer Group Savoie, has deployed these systems at institutions and hospitals in Atlantic Canada, and is looking to deploy them in remote locations. This approach follows a model used in Scandinavia, which uses biomass district heating and the State of Vermont which now heats many of the State's elementary schools with biomass.

The supply chain for biomass-fired district heating systems is composed primarily of fuel, and a boiler. According to Compact Appliances, opportunities to employ a cogeneration system in remote locations are probably limited. However, if the system is operated to co-generate electricity, then a steam turbine-generator is also employed as follows (a heat-only system would simply eliminate that component):

Figure 9 – Biomass Cogeneration Schematic



Source: German Renewable Energies Agency.

Bottlenecks and Opportunities

No specific bottlenecks were identified in this technology segment. Compact Appliances has had no difficulty procuring either the required fuel feedstock or the required boilers in order to install their systems. Boilers are currently purchased from either US or European manufacturers, and the company has the capability of completing an installation on a turnkey basis, including construction of a boiler enclosure and a fuel storage building, installation of equipment, and operation and maintenance. Further, suppliers to Compact Appliances have not expressed any supply chain issues aside from a 9-10-month lead time for delivery.

As mentioned in the Biomass section above, the thermal systems used for residential and district heating applications require pellets derived from high-quality mill residue. Growing constraints on the supply of mill residue in Atlantic Canada threaten to curtail the domestic growth opportunities of biomass for thermal combustion. On the other hand, innovations in these remote district heating systems that would allow for the usage of pellets created from forest biomass could greatly improve growth prospects.

Appendix A - List of Interviews

ORGANIZATION	INDIVIDUAL	TITLE
American Wind Energy Association	Chris Long	Manager, Offshore Wind and Siting Policy
Barrett Enterprises	Robin Barrett	(family owned)
Business New Brunswick	Eddie Kinley	Senior Project Executive
Canadian Biomass Association	Bruce McCallum	Director, Maritimes Working Group
Canadian Wind Energy Association		
Compact Appliances	Malcolm Fisher	Sales
DSME Trenton		
Enercon		
Fundy Ocean Research Center for Energy (FORCE)	Doug Keefe	Executive Director
Frontier Power Systems	Carl Brothers	President
Fundy Tidal, Inc.	Dana Morin	President
GDF Suez		
JD Irving	Graham Curren	Director of Marine Business Development, Irving Transportation Services
MacAskill Associates	Allan MacAskill	Director
The Maritimes Energy Association	Barbara Pike	Executive Director
New Brunswick Forestry Products Association	Mark Arsenault	President & CEO
Nova Scotia Power	Roger Burton Pam McKinnon Marie Thomas	Senior Director, Projects Director, Wind Energy Facility Representative
Ocean Renewable Energy Group	Chris Campbell	Executive Director
PEI Energy	Mark Victor	Special Projects Coordinator
Renewable Energy Services Ltd	Allison Leil Jr.	COO
Shaw Resources	Gordon Dickie	General Manager
Seaforth Energy	Mike Morris	President
Shear Wind	Ian Tillard	COO
Verboom Grinders	Jim Verboom	Partner/Founder

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Research, Development and Demonstration: Challenges and Opportunities Atlantic Canada Opportunities Agency

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INTRODUCTION

The Atlantic Canada Opportunities Agency has asked SLR Consulting (Canada) Ltd., in partnership with Maxis Energy Solutions, to examine the current state of clean and renewable energy research, development and demonstration (RD & D) in Atlantic Canada and provide observations and advice that will assist the Atlantic Energy Gateway (AEG) initiative in the development of a strategy to facilitate and incent the progress of that sector.

Energy supply and security is a critical part of our society. In Atlantic Canada, the four provinces have very different energy resources and electrical energy generation mixes. As with much of the world, Atlantic Canada is moving toward a more diverse energy portfolio, and energy sources that produce less greenhouse gases emissions. Through this process, our region has an opportunity to capitalize on our resources and strengthen both our environmental stewardship and our economic standing.

The Atlantic Energy Gateway initiative is facilitating increased cooperation between the four Atlantic Provinces and encouraging the development of the Atlantic region's clean and renewable energy resources. As part of this effort, the AEG is engaged in the creation of a strategic and factual foundation with respect to the development of the region's clean and renewable energy potential.

The Atlantic region has natural resources that can yield significant, new and expanded clean energy sources, including tidal energy, hydroelectric power, wave energy, biomass sources, and wind power. The contributions that our scientific and technical communities are making to the development of clean energy are helping to advance clean energy initiatives around the world.

The AEG commissioned this study to gain a more complete picture of the clean and renewable energy RD&D activities in Atlantic Canada, both in terms of types of technologies being pursued, and the intellection and institutional resources present in the region. Based on this information, the AEG sought analysis and suggestions to help direct future strategies.

This report presents summaries of the current state of clean and renewable energy used in each of the four Atlantic Provinces and a summary of research and development capacity. Following from those sections of the report, a detailed review of four major projects is provided that leads to a discussion of the qualities of an effective RD&D project. Potential areas of regional cooperation are then presented, along with a series of policy considerations intended to support the AEG's clean and renewable energy development initiatives.

SECTION 1 REGIONAL DISCUSSION - CLEAN ENERGY GOALS AND PRIORITIES: BROAD AREAS OF SHARED INTEREST AND POTENTIAL COOPERATION

1.1 Newfoundland and Labrador

NL Background

In 2009, 97% of Newfoundland and Labrador's electricity was generated from hydropower, with the remainder derived from oil, diesel, natural gas and some wind. About 30% of the Province's GDP is related to energy, the highest percentage in the country, and NL exports three times more electricity than is used domestically.

With installed capacity of over 6,700 MW from 40 plants, most of which (>5,400) is generated at Churchill Falls (Labrador) (and sold to Hydro Quebec through a long-term agreement), NL can be viewed as Atlantic Canada’s clean energy leader in terms of resource and electrical generation. Outside of hydro-electricity, Newfoundland and Labrador Hydro operates 1 oil-fired generating station, 4 gas turbine generating stations and 25 diesel-fired thermal plants. Newfoundland and Labrador Power operates gas turbine generating stations and diesel-fired plants (Canadian Centre for Energy). In addition to larger hydro facilities and its main grid, Newfoundland and Labrador Hydro provides electricity to rural “off grid” customers via small hydro and thermal diesel plants, many of which are located in isolated communities in coastal Labrador and southern Newfoundland (the Island).

One biomass plant with 15 MW of installed capacity, using bark, sludge and sawmill shavings, is located at Corner Brook Pulp and Paper, where a biomass cogeneration (combined heat and power) system has been in operation since 2003.

A total capacity of 54 MW of wind energy is installed in 2 wind farms at St. Lawrence (27MW) and Fermeuse (27MW), which is low in comparison to other Atlantic (and other Canadian) Provinces. Nalcor is engaged in an RD&D project at Ramea as part of a wind-hydrogen-diesel energy project. NL is known to have a significant wind resource, but development is limited due to an 80 MW limit on the amount of wind energy that can be integrated into the grid. Nalcor recommended the 80MW upper limit based constraints identified in a 2004 review, and are still applicable today as the power system has not substantially changed: These constraints are (from MHI Report):

- *Water Management: Additional wind generation would cause less generation from hydro facilities and therefore more water would be spilled from reservoirs. For example, adding 20 MW to the upper limit of 80 MW, the amount of spillage would double from 9 GWh to 19 GWh on an annual basis.*
  - *Transmission grid security: Non-dispatchable generation could displace the demand from the hydro generation and cause the transmission network to be lightly loaded in certain areas resulting in an overvoltage condition. A small disruption to the system could cause widespread system disturbances.*
  - *Regional transmission issue: A possible overvoltage condition due to limited voltage control provided by wind generation.*

NL Clean Energy Goals

Components of Newfoundland and Labrador’s “Energy Warehouse” are outlined in the 2007 Energy Plan entitled Focusing Our Energy. In terms of clean energy, “untapped potential also exists in other energy sources, such as wave and tidal energy, wood, peat, methane captured from landfills and solar energy in some areas."

NL's plans to advance the lower Churchill project are well known. The existing 5,428 MW (noted previously) has been generating power from Churchill Falls since 1971. Remaining potential sites for development exist at two locations on the lower Churchill River, known as the Lower Churchill Project (LCP). “The Lower Churchill Generation Project's two proposed installations, Gull Island and Muskrat Falls, will have a combined capacity of 3,074 MW and can provide 16.7 Terawatt hours of electricity per year. That is enough to supply hundreds of thousands of households annually and contribute significantly to the reduction of air emissions from thermal, coal and fossil fuel power generation" (www.nalcorenergy.com). The Muskrat Falls Generating Station will have a capacity of 824 megawatts and annual energy production of 4.9 Terawatt hours. A transmission line interconnection will be made between Muskrat and Churchill Falls, and a 1,100 km long Labrador-Island Transmission Link will be constructed from Muskrat Falls to Soldiers Ponds in the eastern Newfoundland (Island), including a 30 km subsea crossing under the Strait of Belle Isle.

Power will be routed to Nova Scotia using existing lines, as well as a new Maritime Link from Bottom Brook, NL, to connect at Lingan, NS. The subsea link will be approximately 180 kilometres long and will have a capacity of 500 megawatts.

In terms of RD&D, "Barriers to development of hydro resources are not technical in nature" rather are more dependent on infrastructure and investment. "Transmission is a key enabler" and innovation can play a role.

NL Clean/Renewable Energy Priorities

Further to the objectives of this report, The Government of NL have taken steps to delve further into prioritizing efforts respecting clean energy technologies. In 2010, the Department of Natural Resources retained the consulting team of E4Tech, Orion Innovations and Wade Locke Economic Consulting to conduct a series of studies and provide recommendations for energy innovation priorities. Energy sources noted in the Energy Plan were reviewed, including crude oil, natural gas, wind, hydro, ocean, biomass, hydrogen, uranium, peat, geothermal, solar, power transmission, and energy efficiency & conservation. In short, nine priority themes across four energy areas were recommended for further road-mapping. With reference to clean energy the specific areas included:

- Onshore Wind – to address barriers impacting onshore wind innovation particularly related to icing, cold conditions, grid inflexibility/integration, and resource mapping
- Transmission – innovation to enhance power line de-icing capabilities with a focus on Labrador conditions
- Remote Energy – remote location power system technologies, with a focus on off-grid settings.

All energy sources underwent a screening based on a number of criteria. While not considered to be the highest priority areas, it is not to say that some of these energy types do not warrant further investigation. It is important to point out that the screening exercise was to determine whether or not to "carry forward" specific technologies for their further detailed innovation analysis. The criterion applied, however, allows general conclusions to be drawn as to the merits of committing resources toward certain energy types. With respect to clean energy technologies under review for this report, the consultants' reports concluded:

Table 1 – Newfoundland and Labrador Energy Source Screening

Energy Type	Sub-Type	Carry Forward for further innovation analysis?	Basis
Wind	Offshore Wind	Yes	Skills and resources are strong
	Small-scale wind	Yes	Some skills in applications engineering and resources are strong
	Novel wind concepts	No	NL capabilities not suited to innovation needs
Ocean	Wave	Yes	Required innovation may match local capabilities. Some local primary resource
	Tidal (instream)	Yes	Required innovation may match local capabilities. Some local primary resource
	Tidal (barrage)	No	No suitable sites particularly in comparison with other locations
	Novel (ocean thermal, osmotic)	No	Limited base to innovate and compete
Biomass	Feedstock supply	No	Limited innovation required. May (however) be an opportunity for provincial businesses
	Waste to energy	No	Modest resource level. Limited innovation base
	First generation biofuels	Yes	Fish oil as opposed to bio crops as a resource
	Lignocellulosic biofuels	No	Limited basis to innovate and compete
	Power generation	No	Technically mature. Limited innovation base
	Small scale heat	No	Technically mature. Innovation already dominated by others
	Large scale heat / CHP	No	Technically mature. Innovation already dominated by others
	Biogas and synthetic natural gas	No	No gas grid. Limited innovation base
Solar		No	Modest resource. Limited innovation base
Geothermal		No	No resource. Limited innovation need. No basis to innovate

To summarize, outside of hydro developments, the Province recognizes potential in the areas of: (1) onshore wind including large conventional turbines, as well as small scale wind; (2) harsh environment transmission; (3) marine energy technologies of offshore wind, wave, and tidal energy; (4) smaller scale first generation biofuels for local use, and; (5) recognizes a business opportunity in feedstock supply of forest related biomass. Additionally, and further to small scale wind and biofuels, the province is focussed on their application at (6) remote off-grid power systems. Caution is noted respecting marine energy technologies in that the province does possess innovation resources and capabilities, however, NL is not likely to be a suitable location for deployment. The opportunity for NL lies in the provision of services to innovators from outside NL who may wish to make use of NL skills and facilities. Consequently, analysis and prioritization within marine energy technologies is less important than the development of an appropriate service- export plan.

Current and Future Projects of Interest: Potential Areas of Regional Cooperation

The resource of Newfoundland's, and primarily Labrador's, rivers offers the province the regionally unique ability to develop hydro-electric power, and in turn provides the province with clean electricity generation. Regional cooperation respecting transmission from NL to the other Atlantic Provinces and beyond is occurring now between NS and NL. As noted earlier, hydro developments are major industrial projects and do not represent RD&D.

The availability of this wealth of clean energy source has negated the need for NL to move forward with the development of other forms of clean energy, primarily onshore wind. The Province already exports most of its produced electricity, and has ample power supply to meet the needs of NL residents. In discussions with representatives of NL's Department of Natural Resources, it was suggested that the link with NS will enable the export of Labrador hydro power, but will additionally provide the means to add island based wind power, primarily for export. As well, there is clearly a medium to long term plan to develop Labrador onshore wind power, also for export, on a large scale.

NL Power's Ramea Wind Energy Project to assist in addressing the needs of off-grid communities, is consistent with NL priorities. It is highlighted as an example of regional (albeit limited) cooperation, and is summarized in Section 3 later in this report. The Province has provided funding for NL Hydro for the Coastal Labrador Alternative Energy Study to identify alternative energy sources for coastal communities now serviced by diesel generators. The primary focus includes wind and small scale hydroelectricity. Work includes hydro site identification, wind prospecting, transmission requirements, and other elements. Another area of focus, as evidenced by current road-mapping efforts overseen by DNR and NL Power/Hydro, is aimed at addressing the challenges of extreme harsh environments on wind turbines and transmission.

While not specifically RD&D, interesting discussions were also held respecting NL's abundant forest based biomass and the promising commercial potential of wood pellets, where three local companies are producing pellets for export. Unlike the three other Atlantic Provinces, where extensive land is privately owned, much of Newfoundland and Labrador's forest resource is held in crown lands. Moreover, NL's land mass has minimal agricultural development when compared to most of the Atlantic Canada region, so forest related would be the only source for biomass.

Areas of regional interest and potential cooperation, in which the experiences of the other three Atlantic Provinces might benefit NL, and the region as a whole, intuitively lies in: onshore wind;

small hydro; the effects of cold/snow/ice on wind turbine performance; small wind technologies; storage and integration technologies, and; forest based biomass and wood pellets.

1.2 New Brunswick

NB Background

NB Power's generating fleet has a total capacity of 3811.4 MW, consisting of hydro (888.1 MW), nuclear (660 MW), thermal (1738.4 MW)and combustion turbine (524.9 MW) sources. In addition, New Brunswick has 260 MW capacity of natural gas, 260 MW of wind, 294 MW of biomass, and 148.4 MW of biogas, and 2.4 MW supplied through net metering, giving an overall capacity of 4516.7 MW.

New Brunswick is in the unique position of being electrically connected to PEI, NS, New England (Maine), Quebec, and in the near future Newfoundland and Labrador. These connections provide New Brunswick with the ability to access electricity from numerous sources, and to be able to move to markets electricity from NB and from regional neighbouring provinces.

NB's Department of Energy released ***The New Brunswick Energy Blueprint*** in October of 2011. It provides a "long term vision and a three year action plan to work toward the objectives" of: low and stable energy prices; energy security; reliability of the electrical system; environmental responsibility, and; effective regulation. The Plan provides a comprehensive list of 20 government actions for the energy sector for the next three years. In general, the approaches contemplated by the NB government include:

- restructuring NB Power to promote greater efficiency and transparency in its operations
- achieving greater efficiency of energy use
- enhancing NB's ability to transition away from fossil fuels and towards stable priced fuel generation to reduce market risk
- ensuring NB energy markets are efficient and well regulated
- working towards more inter-governmental cooperation in terms of policies and projects
- optimizing strategic advantages in regional energy markets
- fostering innovation and improved energy technologies
- an on-going commitment to public, stakeholder and New Brunswick First Nations dialogue regarding energy issues, opportunities, challenges and solutions

NB Energy Goals

New Brunswick currently derives 28 percent of its in-province electricity demand from the clean energy sources of wind, biomass and hydro. It will create a new Renewable Portfolio Standard requiring NB power to increase this to 40 percent by 2020. It is noted in the plan that renewable energy imports such as hydro power from Quebec and Newfoundland and Labrador will be eligible under certain conditions. With the Point Lepreau nuclear station back on line this year, an added 35 percent will come from non-emitting energy, resulting in a total of 75 percent of NB's electricity demand coming from non-emitting or renewable energy sources.

Noted earlier, the NB Energy Blueprint provides a comprehensive list of 20 government actions for the energy sector. These specific actions fall under the following headings:

1. Reintegration of NB Power
   - Amalgamate NB Power group into a single vertically integrated crown corporation.

2. Electricity market and New Brunswick System Operator
   - Review electricity market policies. Implement appropriate structural and operational changes, including the dissolution of the NB System Operator and migration of the system operator functions back to NB Power.

3. NB Power – debt management plan
   - NB Power is to implement a debt management plan, allowing it to reduce debt and create shareholders equity.

4. NB Power – regulatory oversight and Integrated Resource Plan
   - NB Power operations will be subject to regulatory oversight and review, and will be required to present an Integrated Resource Plan every three years, and a Financial Forecast annually to the NB Energy and Utilities Board (EUB), or as directed by the EUB.

5. Regional electricity partnerships
   - Pursue regional electricity agreements, joint ventures and partnerships where there are positive commercial outcomes for NB Power and defined benefits for New Brunswick ratepayers.

6. Smart grid technology and innovation
   - Expand the network of smart grid stakeholders and partnerships and work with existing and new smart grid pilot projects.

7. Large Industrial Renewable Energy Purchase Plan (LIREPP)
   - Bring qualifying large industrial companies' electricity costs in line with their Canadian competitors by implementing a LIREPP.

8. Renewable Portfolio Standard (RPS)
   - Increase the Renewable Portfolio Standard to a minimum of 40 percent of NB Power's in-province sales by 2020.

9. Future development of renewable energy resources
   - Support local and First Nations small scale renewable projects
   - Integrate current and future wind generation in the most cost effective and efficient manner.
   - Support promising solar, bio-energy and other emerging renewable energy technologies.

10. Wood based biomass resource
    - Develop and implement supporting policies to optimize the energy output from wood based biomass resources with a specific focus on pellets.

11. Energy and climate change
    - Develop the key energy components for the 2012 – 2020 New Brunswick Climate Change Action Plan.

12. Electricity efficiency plan
    - Utilities, in conjunction with Efficiency NB, will be required to prepare a three year electricity efficiency plan.

13. Energy efficiency building code standards
    - Minimum efficiency standards will be required for new building construction by adopting national standards.
    - The New Brunswick Building Code Act will be amended to create the authority to do so.

14. Energy efficient appliances and equipment
    - Upgrade the list of regulated appliances and equipment under the *Energy Efficiency Act*.

15. Natural gas distribution rates
    - Review the natural gas rate structure and distribution network with the objective of achieving a cost-based rate structure and improve access to natural gas across the province.

16. Petroleum products pricing
    - Perform a comprehensive review of the Petroleum Products Pricing Act and Regulations for the purposes of ensuring its continued effectiveness in achieving the objectives of petroleum price stability, while ensuring the lowest possible price to the consumed without jeopardizing the continuity of supply.

17. Energy and Utilities Board
    - Restructure the Energy and Utilities Board to consist of exclusively full time members.

18. Office of the Public Energy Advocate
    - Establish and appoint a full time public energy advocate to replace the system of ad hoc appointment of public interveners.

19. Energy literacy, education and skills development
    - Develop an energy sector workforce development strategy
    - Pilot an energy certificate program
    - Implement an energy lit, education and awareness campaign.

20. Energy research and development
    - Develop and implement a New Brunswick energy sector research and development strategy supporting the adoption of emerging clean energy technologies.

NB Current and Future Projects of Interest: Potential Areas of Regional Cooperation

The NB Energy Blueprint notes that the province's electricity system is well-positioned to serve its needs for many years, and that "no significant capital expenditures to replace or refurbish current electrical infrastructure are expected over the next decade." Clearly, demand side management, energy efficiency, and the role of smart grid technology, is a high priority for NB utilities and the NB government.

Consistent with this priority, NB is a key player in the PowerShift Atlantic smart grid pilot project. PowerShift is further described in Section 3. Briefly, it is a regional demonstration project, using pilot programs with residential and commercial customers, focused on finding more effective ways of integrating wind energy into the electrical system in the Maritime Provinces. Smart grid innovations enable homes and businesses to better manage energy consumption.

NB supports continued regional cooperation where it benefits the province, and mentions the Atlantic Energy Gateway (AEG) Project as being a “launching pad for detailed discussions and studies of potential benefits of regional electricity cooperation, including enhanced system integration, expanding clean and renewable energy sources, and regional transmission planning.” initiative in its Blueprint. It is believed that NB “could take on more intermittent renewable electricity sources, such as wind and solar energy, if such capacities were backed up and balanced by larger regional generation and load base.”

New Brunswick has been successful in integrating and balancing significant wind power in to the electrical system. The intermittent nature of wind, however, often leads to missed opportunities respecting cost savings from out-sourced energy purchases, and sales. New Brunswick’s next phase of renewable energy development will focus on smaller scale projects with a particular emphasis on non-intermittent sources such as wood based biomass. Wind energy will continue to be integrated, but in “measured and manageable stages.”

Competitive Requests for Proposals will be undertaken for small scale renewable projects, and a portion will be set aside for First Nations Projects. RFP approaches in NB, and NS, as well as the Large Industrial Renewable Energy Purchase Program (biomass and river hydro), appear to have potential for more regional cooperation and information sharing regarding approaches, success, challenges and a range of other related issues.

Given the interest in biomass in all four Atlantic Provinces, another area of potential regional cooperation may be built on New Brunswick interest in advancing biomass and wood pellets. NB’s Blueprint outlines a number of initiatives including: resource mapping; wood pellet industry research, best-practices (standards, QA/QC, certification, etc); and district heating & cogeneration applications and practices. Specifically the Blueprint notes that the U.S. Pellet Fuels Institute is developing standards for the U.S. Environmental Protection Agency. It points to “an opportunity for New Brunswick to lead in the development and expansion of (the) pellet industry by adopting pellet standards, possibly in conjunction with other Atlantic Provinces.

In summary, areas of shared regional interest might include: smart grid technologies and other issues related to demand side management; wind balancing and integration; smaller scale renewable energy developments – biomass, small hydro, wind; community, First Nations, and large industry involvement, and; biomass and wood pellets.

1.3 Prince Edward Island

PEI Background

Having no fossil fuel, nuclear or hydroelectric resources of its own, Prince Edward Island relies primarily on imported energy for transportation, electrical and heating needs. The PEI Energy Corporation is responsible for pursuing and promoting the development of energy systems and the generation, production, transmission and distribution of energy, in all its forms, on an economic and efficient basis. In February 2012, PEI's total energy mix comprised 77% petroleum products, 13.5% electricity and 9.5% biomass. Petroleum products are used primarily as transportation fuel and for home heating. Wind resources supply roughly 18% of the electricity demand with the remainder tied primarily to fossil fuel and nuclear power imported from New Brunswick. PEI is home to the Wind Energy Institute of Canada (WEICan), which aims to advance the development of wind energy across Canada through research, testing, demonstration, training and collaboration. Biomass use is primarily firewood; sawmill residue and municipal waste for the generation of heat. To a lesser extent, cereal grains, oil seeds and crop residues are being used for biogas and heating use. Solar and geothermal energy are used for active and passive residential and commercial heat.

With the exception of Canada's northern communities, PEI has the highest electricity rates in Canada and despite being a leader in the use of wind energy for electricity generation, PEI relies primarily on imported electricity from New Brunswick to meet its total annual consumption of about 1.1 million megawatt hours (MWh). Two undersea cables transmit electricity to and from New Brunswick and Prince Edward Island. Two local utilities, Maritime Electric and Summerside Electric, provide 90% and 10%, respectively, of the Island's electrical needs. PEI's average electricity load is about 160 megawatts (MW), peaking at about 220 MW. When the load exceeds about 200 MW, PEI's utilities rely on locally generated electricity from wind and petroleum products. Of the 164 MW of wind generation capacity, 74 MW is dedicated for local distribution with the remainder used for export. A total of nine oil-fired generating units, with a combined capacity of 161 MW, are used only as a last resort.

Over the past 10 years, reliance on imported electricity, with fluctuating and ever increasing prices, has been addressed through provincial energy strategies (2004 and 2008). A new Prince Edward Island Energy Accord, implemented in March of 2011, focuses on lowering and stabilizing electricity rates and increasing the use of locally generated wind energy. Pursuing renewable energy development offers an alternative to conventional sources and provides greater control of energy prices, security, and diversity of supply.

PEI Clean Energy Goals

In 2004, PEI released its *Energy Framework and Renewable Energy Strategy,* which contained 19 objectives that encouraged and promoted energy efficiency and the use of renewable energy for fuels and electricity.

1. Committing to a Renewable Portfolio Standard for electricity of at least 15 per cent by 2010.
2. Maritime Electric Company Ltd. to file an Open Access Transmission Tariff with the Island Regulatory and Appeals Commission.
3. Evaluating the feasibility of biomass-fueled generating systems to determine their suitability for economical power generation.
4. Endorsing the use of solar technology, particularly for meeting domestic hot water requirements.

5. Continuing to evaluate the economic viability of an ethanol and bio-diesel industry in Prince Edward Island.
6. Evaluating the economic feasibility of collecting biogas from meat packing wastes for energy production.
7. Showing its leadership by immediately introducing transportation efficiency standards for new or replacement vehicles in its fleet.
8. Exploring with the Cities of Charlottetown and Summerside options for the development of public transportation systems.
9. Encouraging the adoption of both the National Building Code and the Model National Energy Code for Houses for new construction to reduce the per capita energy consumption within the residential sector.
10. Implementing electricity efficiency programs within its public buildings.
11. Requiring Maritime Electric Company Ltd. to file an approved energy efficiency plan and demand side management strategy with the Island Regulatory and Appeals Commission.
12. Allowing the PEI Energy Corporation to remain actively involved in advancing and developing wind projects in Prince Edward Island.
13. Exploring the possibility of removing the sales tax on all components of wind turbines.
14. Incorporating net metering for small wind power in statute to promote this development.
15. Evaluating manners of public compensation that may accrue from power generated from large wind facilities that are specifically developed to meet electricity export markets.
16. Ensuring the economic viability of community or wind cooperative systems by guaranteeing a selling price to the utility of up to 85 per cent of the retail residential rate.
17. Pursuing a method of enabling Prince Edward Island residents to invest in local wind energy projects.
18. Embarking on a monitoring program that systematically appraises the wind profiles of the island.
19. Formulating a possible role in advancing, demonstrating and deploying wind-hydrogren technology in Prince Edward Island.

In 2008, PEI released *Securing Our Future*, a three volume energy policy series that built on the objectives set out in 2004 and focused on v.1) Wind Energy; v.2) Energy Strategy; and v.3) Climate Change Action. The 2008 strategy doubled the RPS to 30% by 2013 and set as a goal the capacity to generate 500 MW of wind energy by 2013. The Strategy offered a 10-point plan for the development of wind energy on PEI.

1. Maximizing Energy Security, Independence and Price Stability for residents
2. Generating Revenue from Green Energy Exports
3. Demonstrating Community Support
4. Building a Collaborative Partnership Approach to Cable and Transmission Planning
5. Maximizing Economic Benefits
6. Promoting Sound Land-Use Planning
7. Assuring Compliance with Environmental Review Processes
8. Promoting Fair and Equitable Land Leases
9. Advancing a Consistent Taxation and Business Support Environment
10. Partnering with Proven Developers

In 2011, the Province of PEI, in partnership with Maritime Electric, implemented the five-year *PEI Energy Accord* with the objectives of:

1. Lowering electricity prices
2. Stabilizing electricity rates
3. Increasing the use of locally owned wind energy

In addition, the accord called for the establishment of the PEI Energy Commission to examine and provide advice on how to achieve these objectives.

PEI Clean/Renewable Energy Priorities

Wind

Prince Edward Island's wind energy resource is clearly one of the province's strongest and most valuable natural assets. As the percent of wind penetration on the Prince Edward Island electric grid increases, the ability to manage the energy input and operation of the grid becomes more complex. The PEI Energy Corporation built Atlantic Canada's first commercial wind farm at North Cape in 2001. Since then, the PEI Energy Corporation, Summerside Electric, Maritime Electric, and independent developers have increased PEI's wind capacity to 164 MW, of which 74 MW is dedicated for domestic use. With new wind energy developments underway, wind is targeted to supply approximately 30% of PEI's electricity by 2013.

Priorities for wind energy include:

1. Doubling of renewable energy portfolio standard from 15% to 30% by 2013.
2. Build out capacity to 500 MW
3. Maximize the benefits of large-scale wind developments for residents of PEI
4. Provide support to WEICan and encourage R&D opportunities for small-, medium- and large-scale wind developments on PEI
5. Facilitate the development of smaller community-based wind projects
6. Explore opportunities for economic development in the manufacturing, service and maintenance of small wind energy systems
7. Develop additional small wind capacity in PEI specifically for local demand and energy security
8. Planning for a third transmission cable between PEI and NB
9. Development of storage technologies

The PEI Energy Corporation also operates the PEI Wind-Hydrogen Village, a project that, similar to the NL Ramea project endeavours to integrate wind energy, hydrogen gas production and electricity generation into a self-supporting system that can be operated off-grid.

Biomass

PEI produces almost 10% of its total energy supply from fuel wood, sawmill residue and municipal waste. PEI Energy Systems uses municipal waste and wood biomass to supply thermal energy to commercial, residential and institutional buildings in Charlottetown. In 2007, PEI established the Environmental and Renewable Industries Committee (ERIC) to examine the potential for local biofuel development. ERIC determined that feedstock for bio-energy applications on PEI could be derived from waste management, forestry, agriculture, fisheries and aquaculture industries. Biomass feedstocks (e.g. wood, cereals, straw, grasses, crop residues), in particular, offered significant potential for space and water heating applications and electrical generation. ERIC recommended the establishment of an Inter-Departmental Biofuels Committee (IDBC) to:

- Evaluate proposals for biofuels projects and studies with a view to making recommendations on their potential economic, environmental, and social benefits to Prince Edward Island.
- Work with biofuels proponents to identify applicable federal and provincial government assistance programs, as well as sources of private sector investment.
- Make recommendations to Executive Council by September 2008 on the feasibility of mandated renewable fuel standards for transportation and/or heating fuels (with and without a requirement for locally produced fuels), and the economic implications of road tax exemptions, rebates, and related policies and measures.
- Identify potential biofuels demonstration projects that can be implemented at government facilities and in government vehicle fleets, thus enabling government to lead by example in the advancement of biofuels.
- Require that the committee's activities be linked conceptually and strategically with the economic innovation strategy being developed by the Office of Bioscience and Economic Innovation.

Biomass challenges:

- Better understand the need to modernize labor regulations for the staffing of small heating plants
- Better understand the environmental and health concerns associated with biomass emissions (i.e. wood smoke)
- Determine the proper role that local biomass resources can play to meet the electrical and thermal requirements of PEI residents
- Ensure that increasing the use of local biomass resources is accomplished in a sustainable fashion
- Determining the proper transition for the production of locally grown feedstock to meet market demand
- Finding/creating the land use balance between food and energy crop production
- Understanding the full environmental, social and economic impacts of individual feedstocks and technology platforms for the production of liquid biofuels

Priorities for biomass energy include:

- Review existing codes and regulatory barriers affecting the further development of biomass fuel in PEI.
- Demonstrate biomass technologies in select public buildings across PEI.
- Actively promote the use and encourage the installation of biomass heating systems in PEI homes and businesses.
- Further investigate the use of biomass in urban district heating systems and the potential for cogeneration facilities with PEI utilities.
- Only be supportive and promote biomass installations that meet acceptable emissions levels.
- Identify and explore opportunities and applications for the utilization of pure plant oils.
- Consider the introduction of escalating Renewable Fuel Standards for ethanol and biodiesel.

- Endorse the concept of a Low Carbon Fuel Standard (LCFS), as a guiding policy framework to reduce GHGs, through the increased use of environmentally and economically sustainable alternative biofuels.
- Engage neighboring Provinces and States in formulating a collaborative regional approach to GHG reduction through the adoption of low carbon fuel standards.

PEI Current and Future Projects of Interest and potential areas of Regional Cooperation

Wind Energy Institute of Canada (WEICan) – Wind Energy Storage

The Wind Energy Institute of Canada (WEICan), with $12M of federal funding from the federal Clean Energy Fund and a $12.8M loan from the PEI government, is developing a 10 MW Wind Energy R&D Park with an energy storage system (Further discussed in Section 3). This research project will look at how energy storage can be utilized to maximize renewable energy production and stabilize the grid. The Wind Energy R&D Park and its data will also be accessible to those researching wind turbines and ancillary equipment. The project will also further WEICan's work in the small wind sector.

Participants in the project include Maritime Electric, NBSO, the regional system operator and academic researchers at UNB. The new asset base will allow WEICan to expand its mandate and provide sector-enabling support, and allow the project to offer a unique test bench for wind and storage systems. The availability of the project for research purposes will allow WEICan to expand its research role into wind forecasting methodologies, grid integration issues, storage facilities, and storage performance with respect to reliability and economics.

The priority will be to demonstrate the integration of a storage system with a small wind farm on a weak distribution system. The Project will be designed in close collaboration with Maritime Electric.

PEI Wind-Hydrogen Village Project

The PEI Wind-Hydrogen Village was developed over the past decade as a research, development and demonstration project that integrates conventional wind energy sources and hydrogen production technologies with the aim of creating an off-grid electricity supply for small, isolated communities. The wind turbines have a combined capacity of approximately 250 kW. Electricity from the turbines powers hydrogen production and storage equipment; the hydrogen is then added to the diesel fuel supply for the genset generator.

Two of this project's attributes set it apart from most other wind-hydrogen projects:

An innovative power supply configuration enables the wind turbines to serve as the sole source of power to the hydrogen production system. To operate off-grid, challenges related to the variability in quantity and quality of power has to be overcome.

The genset uses common diesel technology modified to allow hydrogen to be injected into the inlet air to displace diesel fuel, allowing the genset to obtain up to 50% of its energy from hydrogen. Although it is currently not cost-competitive with conventional diesel generation, it may compete in certain niche markets such as northern and remote communities of Canada and beyond.

Maritime Electric – PowerShift Atlantic

Maritime Electric is involved in PowerShift Atlantic, discussed throughout various sections of this report (see Section 3), through its participation in the Residential Research Program within PowerShift. Potential residential participants have electric appliances in their homes that qualify for the program. 200 PEI residences have been selected to have a device installed on the qualified appliance that will enable Maritime Electric to monitor and control appliance loads. The program is in its early stage.

Town of Summerside – Load Switching Pilot Project

The Town of Summerside receives power from Summerside Electric, a utility owned by the town. The utility imports 51% of its electricity from New Brunswick. 49% of its power needs are generated on PEI either from the West Cape wind farm, the utility's 10 MW diesel turbine, or their new $30M Summerside wind farm. Summerside has embarked on a $2M pilot project using smart controls that could boost the performance of its wind farm by making the most efficient use of the wind when it's available. The controls indicate when wind power is available and can also be hooked up so that some appliances turn on automatically when wind energy is available. The utility can charge ceramic furnaces during off peak hours for load shifting. Households involved in the pilot can lease or buy high efficiency electric furnaces or water heaters that are connected to and controlled by the Summerside Utility via optical fibre internet connections. The cost of the high speed internet connection is included in the modest monthly lease charge. 100 smart control boxes are being used for the pilot that will expand to a 500-user demonstration.

PEI Renewable Energy Initiative

The Renewable Energy Initiative (REI) is a $7 M program offered through the Agricultural Flexibility Fund, a cost-sharing agreement between the Government of Canada and the Province of Prince Edward Island. The program is delivered by the P.E.I. Department of Agriculture in cooperation with the provincial Office of Energy Efficiency. Renewable energy sources can provide farmers with a degree of energy independence while improving both the individual farms and the agriculture sectors environmental footprint. Renewable energy is perceived as a major opportunity for farms on Prince Edward Island to reduce their energy input costs. This initiative is part of the overall effort to increase the competitiveness of the agriculture sector.

The REI provides financial assistance towards farm energy audits and the implementation of on-farm renewable energy systems. The purpose of the REI is to demonstrate the potential for on-farm renewable energy to improve farm net income while enhancing environmental sustainability. There are three components to the program:

1. On-Farm Energy Audit (a pre-requisite for Component 2)
2. Implementation of Renewable Energy Systems
3. Post Energy Audit (compulsory for those who receive funding

Potential for regional collaboration therefore resides in all areas (large and small) of the wind sector. Bioenergy is a component of the Renewable Energy Initiative, and biomass and biofuels are of great interest to PEI. Some interest may exist in tidal lagoon potential in the Northumberland Strait. AS well PEI was once a per capita leader in solar thermal residential use. Finally geothermal heat pumps are in use in commercial buildings in Charlottetown.

1.4 Nova Scotia

NS Background

Nova Scotia generates electricity from coal, petroleum coke, fuel oil, natural gas, biomass, wind, hydropower, and tidal energy. The largest component, approximately 65 percent on an installed capacity basis, comes from thermal plants owned and operated by Nova Scotia Power Inc., the province's privately-owned electrical utility.

Nova Scotia has four coal- and petroleum coke-fired generating stations with a combined installed capacity of 1,252 MW (see below). The Tufts Cove Generating Station in Dartmouth is the only natural gas-fired power plant in Nova Scotia, equipped with three generation units and two combustion turbines. With an installed capacity of 450 MW, it is the second largest generating station in the Province. The new heat recovery generator has a capacity of 50 MW and uses waste heat from the two combustion turbines as well as added natural gas (Nova Scotia Power).

In addition, Nova Scotia Power operates nine fuel-oil fired combustion turbines in Burnside Industrial Park, Tusket and Victoria Junction with a combined capacity of 222 MW. These turbines are primarily used to address peak demand loads and as back-up for intermittent generation supplies such as wind energy.

Three biomass-fuelled electrical generating facilities with a combined capacity of 46 MW are located in the province. All are operated by private companies with the largest being the Brooklyn Power Corporation in Queens County with a capacity of 21 MW. Two smaller facilities are associated with sawmills in the province. Nova Scotia Power is currently constructing a fourth biomass plant in Point Tupper, Richmond County that will have a capacity of 60 MW.

In terms of Renewable Electricity, Nova Scotia has 33 hydro generating stations, with a total installed capacity of 360 MW. The two units at Wreck Cove account for 220 MW of that capacity. The Annapolis Tidal Power Plant, the only tidal power plant in North America, has an installed capacity of 20 MW.

Nova Scotia has a total of 34 wind farms (including single turbines) with a combined installed capacity of 317 MW, up from approximately 200 MW at the end of 2010. This includes a total of 181 turbines of 0.5 MW and greater capacity located primarily in Northern Nova Scotia, Cape Breton and Southwestern Nova Scotia (Nova Scotia Power).

NS Clean Energy Goals

Over the last decade interest in reducing the province's Greenhouse Gas emissions has grown significantly, especially as it relates to electricity production. Nova Scotia's efforts to reduce Greenhouse Gas emissions are based on the high percentage of coal-based generation, from which it derives the highest percentage of its total capacity from fossil fuels (approximately 57 percent) when compared to the three other Atlantic provinces.

In 2010, the Province of Nova Scotia released a Renewable Electricity Plan that includes a detailed program to significantly alter the province's mix of electricity generation. At the time, nearly 90 percent of the province's electricity supply came from fossil fuels, a result of Nova Scotia's historical coal mining industry.

To accomplish this, regulations were enacted that commit the province to reach 25 percent in-province renewable electricity sources by 2015. A target of 40% of electricity generation from renewable by 2020 has also been established, which would quadruple the amount of renewable electricity generation capacity in 10 years.

In addition to electricity-based clean energy goals, the province made a commitment to support renewable thermal energy in Nova Scotia. These additional technologies include geothermal heating and cooling and biomass-source heating. Both of these programs are financially supported through Efficiency Nova Scotia programs that incentivise their inclusion in new construction and use as replacements for oil and electricity-based heating sources.

NS Clean/Renewable Energy Priorities

While energy efficiency remains a high priority with its own set of programs, the focus of the shift to renewable energy is new, with an emphasis on energy sources located within the province. The new capacity will be created through four mechanisms:

- Community feed-in tariffs (ComFITs): Community-based projects lead by non-profit group, First Nations, municipalities, institutions or for-profit entities employing a Community Economic Development Investment Fund (CEDIF). These projects must employ wind, hydro, tidal or biomass technologies that meet the ComFIT requirements. A goal of 100 MW of capacity has been established for this mechanism.
- Independent Power Producers: A Request for Proposal process established by a new Renewable Electricity Administrator will be used to establish contracts for large and medium-sized renewable energy projects. An equal amount of electricity generation capacity will be procured through continued RFPs issued by Nova Scotia Power Inc. The Utility and Review Board (UARB) will evaluate and approve NSPI-sponsored projects in the traditional way. While technologies are not prescribed for these RFP processes, it is expected that wind energy, biomass and tidal energy will fill the requirements.
- Extra-provincial sources: through agreement with generators in other provinces, renewable electricity will be procured to provide a large source of electricity that will both reach the 2020 goal of 40 percent renewable electricity generation, and provide a source that can balance intermittent local sources such as wind and tidal. Currently, Nova Scotia is looking to the proposed Muskrat Falls hydroelectric project on the Lower

Churchill as the source that would meet the requirements of this component of the Renewable Electricity Plan (refer to Section 1.1).

- Net metering: individuals and small businesses can, within the program requirements, establish their own distribution grid-connected sources of renewable energy and offset the cost of the electricity that they use. This existing program has been enhanced to allow greater generating limits and to provide retail rate compensation for excess electricity generated over a given one-year period.

NS Current and Future Projects of Interest

Of the energy sources expected to provide the required generation capacity described in the preceding section, tidal energy converters are the only non-commercialized technology. Due to the unique and abundant tidal resources in Nova Scotia, major research, development and demonstration initiatives are underway with the aim of achieving commercial-scale deployment of tidal energy converters that will provide a significant generating capacity. These initiatives are discussed in Section 3.3, but are summarized below:

- Environmental Impacts – primarily conducted through Acadia University's Centre for Estuarine Research, several projects are underway that examine the potential effects of tidal energy converters on marine life and the physical environment of the Bay of Fundy.
- Resource evaluation – numerical modelling to produce high resolution simulations of tidal currents in the Bay of Fundy, focussing on key tidal energy resource areas including the Minas Passage, Grand Passage and Petite Passage. Potential effects of the presence of turbines and arrays of turbines are also being modelled.
- Technology Demonstration – The Fundy Ocean Research Centre for Energy (FORCE) has established a technology demonstration site in the Minas Passage and will install transmission cables to connect the four berths to the provincial grid in 2012. Funded by the Province of Nova Scotia, the Federal government, EnCana and the berth holders, FORCE has established a program to allow technology developers to deploy tidal energy conversion devices with the goal of developing a commercially-viable marine energy industry in Nova Scotia.
- Wind projects have accounted for the majority of new renewable energy in Nova Scotia over the past several years, and will continue to be the main source of new renewables helping to meet the 2015 target of 25 percent of electricity generation from renewable sources. While the technology is well-established, RD&D activities are being conducted in Nova Scotia to address issues related to turbine tower manufacturing, blade de-icing, and two small-scale wind technologies: the expansion of Seaforth Energy's product line and market share; and the optimization of a turbine intended for use in agricultural and rural settings.

A new 60 MW biomass facility is under construction in Point Tupper, Nova Scotia by Nova Scotia Power Inc. This facility will help to close the gap on the 2015 renewable electricity target while providing steam to the adjacent pulp and paper mill. In addition to this industrial development, a number of RD&D projects are underway as discussed in Section 2, including the use of marine biomass to produce fuels, the use of fast-growing agricultural crops to produce pellets, and the use of biomass to produce high-value chemicals.

NS Potential Areas of Regional Cooperation

Nova Scotia's current track for the development of clean energy presents several opportunities for collaboration and cooperation. The largest and most well-known is the development of the Lower Churchill project and the related transmission lines connecting it with Nova Scotia. The project involves the two provincial governments and the provincial utility companies and presents significant future opportunities for cooperation through the establishment of the first grid connections between the island of Newfoundland and mainland North America. These opportunities primarily relate to Newfoundland and Labrador's capability to export renewable electricity, and thereby be a potential supplier of the same to the other three Atlantic Provinces.

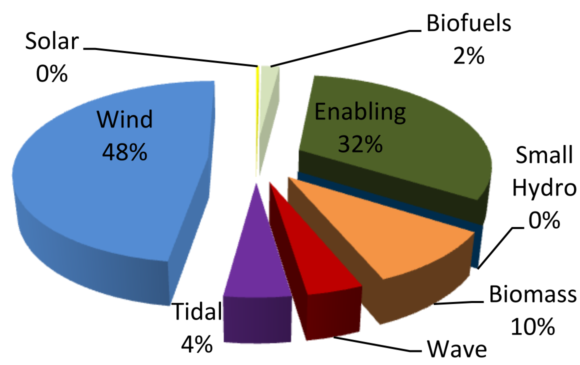
The use of various forms of biomass to generate heat and electricity has been identified as a focus area in Nova Scotia, New Brunswick and Prince Edward Island, where the agriculture and forest industries are interested in opportunities to supplement or replace traditional markets. Potential exists to cooperate in RD&D activities related to crop selection and productivity, processing methods, and technologies for conversion to fuels.

While Nova Scotia has the largest accessible tidal resource in Atlantic Canada, New Brunswick and Newfoundland and Labrador also have significant resources. The RD&D work currently underway in Nova Scotia, both for large and small-scale tidal conversion, presents a tremendous opportunity for the entire Atlantic region. Collaboration among researchers at government, industry and academic institutions in Nova Scotia, PEI, New Brunswick, and Newfoundland and Labrador provides opportunities for innovation that will assist in advancing the sector towards commercialization. Research capacity in science and engineering at the region's academic institutions and government labs, coupled with world class marine research infrastructure at the region's research facilities, along with a vibrant marine industry could all contribute to making Canada's marine renewable energy sector highly competitive in the global marketplace.

SECTION 2 CLEAN ENERGY RESEARCH AND DEVELOPMENT CAPACITY THROUGHOUT ATLANTIC CANADA

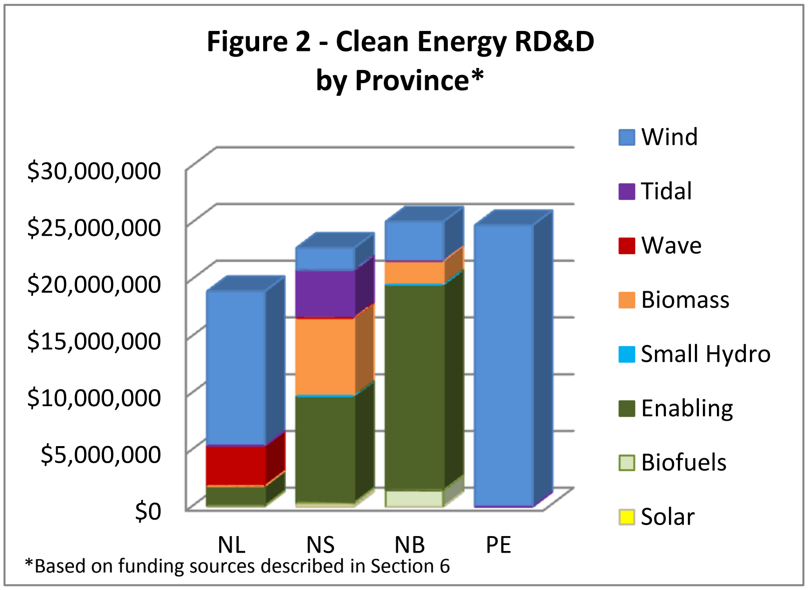
Clean energy RD&D is being conducted in academic institutions, by researchers, and involving the private sector, throughout Atlantic Canada, with localized focus on specialty areas of interest. Continued advancement in clean energy solutions and enabling technologies will effectively increase the capacity of each individual Atlantic Provinces to excel and provide stability to a future Pan-Atlantic working partnership.

Figure 1 - Total Clean Energy RD&D in Atlantic Canada*



*Based on funding sources described in Section 6

Funding for the various researchers, institutions and programs has been a key component of the current Pan-Atlantic clean energy success. For example, "Since 2006, more than $343 million has been invested through the Atlantic Innovation Fund (AIF) in 145 RD&D projects throughout Atlantic Canada" as was noted on the ACOA website. With increased interest in the expertise and innovation within the Atlantic region it is apparent that all four provinces are poised to provide localized efficient resources for a clean energy economy.

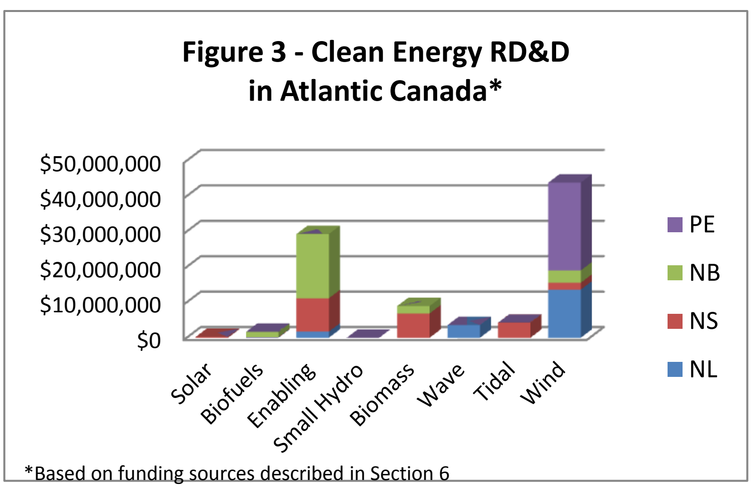


Each province has goals for their sustainable initiatives as detailed in the previous sections. The following capacity charts are constructed based on the main funding agencies project support over the last number of years. The reader is cautioned that the dollar values represent those reported through publicly available sources of the funding bodies noted. It does not reflect added funding through the leveraging sources. It nevertheless provides an order of magnitude picture of clean energy capacity for each province.

Figures 1 through 3 provide a summary of clean energy area project dollar values across the region. In terms of regional spread, most funding for clean energy is focussed on wind, enabling technologies often related to wind, and biomass/biofuels. Localized capacity exists in tidal (NS), wave (NL) and some solar (NS).

2.1 Newfoundland and Labrador

Areas of Clean energy R&D in NL appears focussed on aspects of: wind energy (wind/hybrid systems, advanced weather forecasting for wind, a craft to access offshore wind farms); two wave energy projects, biofuels from fish oil and forest residue; and; a number of enabling technology applications, namely fuel cell work led by Dr. Peter Pickup. Academic work is focussed at Memorial University and to a lesser extent at the College of the North Atlantic, often in conjunction with Nalcor or NL Hydro. While not incorporated in Figure 3, Nalcor and NL Hydro have and continue to complete studies in hybrid systems, wind and wind



environments, small hydro and hydro related climate / environmental studies, but much of this work cannot be considered R&D or RD&D.

Overall much Energy R&D focus in NL has been aimed at providing solutions to challenges in oil and gas exploration and development. This, coupled with NL's clean energy from hydro and grid limitations, again has negated a need to prioritize R&D in wind and other alternative energy sources.

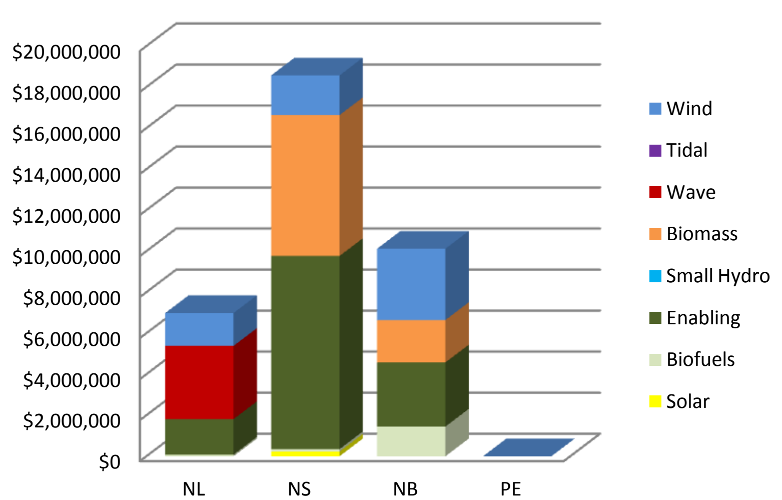
2.2 New Brunswick

In New Brunswick, much RD&D work in concentrated in areas of enabling technologies of demand side management (DSM), hydrogen storage and fuel cells. Through PowerShift, NB is leading DSM efforts. There is additional capacity in biomass/biofuels and ongoing work related to wind. UNB has developed a unique capacity under Dr. Luichen Chang's Sustainable Power Research Group. Dr. Chang is the lead and/or participant researcher in several projects concentrated on distributed generators, hydrogen and fuel cell technologies, as noted under the Wind-to-Hydrogen Atlantic Workshop, and is a member of the NSERC Wind Energy Strategic Network (WESNet), which partners with numerous enterprises, federal and provincial agencies and utilities across Canada, and the Wind Energy Institute of Canada.

2.3 Nova Scotia

Given Nova Scotia's immense tidal resources, particularly in the Bay of Fundy, untapped clean energy resources are present that could allow Nova Scotia to become a leader in marine energy conversion. Additionally, with the advancements of leading university institutions, such as Acadia University, tidal power innovation could be shared with other Atlantic Canada provinces. Tidal power expertise within Nova Scotia is also provided by RD&D completed by FORCE. NS R&D capacity in biomass energy is significant, and other provinces should look to partnerships with the NS academic community. As well, Mr. Jeffrey Dahn at Dalhousie leads efforts in advanced related enabling technologies (fuel cells). It is noted that Dahn and Memorial's Mr. Peter Pickup have partnered on strategic projects.

Figure 4 - Funding Excluding Major Projects*



*Based on funding sources described in Section 6

2.4 Prince Edward Island

Prince Edward Island leads the region in wind energy technologies and RD&D. Funding for a wind/storage project PE was provided by CEF and the PEI Government. This project consisted of the development of the Wind Energy R&D Park and Storage System for Innovation in Grid Integration (Park).

Energy storage systems and development of enabling technologies will be key R&D components at the Park. It is recognized that the above noted charts are heavily skewed toward wind and enabling technologies due to large dollar amounts of funding provided under the Clean Energy Fund to three of the four primary RD&D projects presented in the following Section 3 (these are NB's PowerShift, NS's Tidal efforts and PEI's wind/storage project.

For interest, removing these projects from the analysis reveals that recent capacity trends are consistent, revealing strengths in the areas of enabling technologies (NS, NB, and NL), biomass (NS, NB), wind (NB, NS, NL) and biofuels (NB) (refer to Figure 4).

SECTION 3 EXAMPLES OF EFFECTIVE RD&D PROJECTS THROUGHOUT ATLANTIC CANADA

Section 1 of this report outlines provincial clean energy priorities as well as the current and future projects that will enable the provinces to achieve these goals. In Section 2, the report focuses on the research capacity and the research infrastructure that exists in Atlantic Canada. Section 4 to follow discusses the components of effective RD&D projects and Section 5 speaks to research areas within Atlantic Canada that may benefit from knowledge sharing and regional cooperation. This component of the report, Section 3, focuses on an example of effective RD&D projects that are underway throughout the region to provide a basis on which to build future effective and collaborative clean energy RD&D projects.

Throughout the duration of the work, select RD&D projects were cited by government and utility representatives as being excellent examples of regional cooperation, as well as government/private sector and academic partnering. An example from each province is discussed.

3.1 Newfoundland and Labrador – Ramea WHD Energy Project

See http://www.nalcorenergy.com/assets/nalcorenergyrameareport_january2010.pdf. A video is available at: www.nr.gov.nl.ca/nr/. The Wind-Hydrogen-Diesel Energy Project (WHD Project), led by Nalcor, makes the community of Ramea, on Northwest Island off the southwest coast of the island of NL, home to one of the world's few wind-hydrogen-diesel energy projects. The $12-million RD&D project, mainly funded by Nalcor/Government of NL, ACOA and Natural Resources Canada (NRCan), has been under development since 2007. Under Nalcor's lead, along with NL, ACOA and NRCan/CANMET, other project partners include NL Hydro, Memorial University and the University of New Brunswick, as well (originally) as Frontier Power. Specifically, academic support has been provided by Engineering and Applied Science, Memorial University; and the Sustainable Power Research Group, University of New Brunswick.

The WHD Project research focuses on integrating traditional diesel generation with wind generation and hydrogen production, storage and generation with the goal to reduce, and ultimately replace, the reliance on diesel generation technology to supply electrical service to remote and isolated grids. The Project involves the design of the overall system and energy management system, procurement of equipment, construction, commissioning and the monitoring/studying system. The WHD project will use wind and hydrogen technology to supplement the diesel requirements of this isolated community. If successful, the technology could wean Ramea off diesel-generated electricity almost entirely and bring cleaner energy to the island and other isolated communities.

Ramea was the site of Canada’s first wind-diesel demonstration project, which was constructed on the island in 2004. Wind now makes up about 10 per cent of Ramea’s electricity supply, offsetting some of the originally entire dependence on diesel generation. The small wind farm included six refurbished 65 kilowatt turbines that produced at times too much energy for the local grid to handle. Nearly 60 per cent was wasted. The new hydrogen aspect is being tested in an effort to solve this problem, and the new wind-hydrogen energy system is expected to reduce the village’s reliance on diesel significantly or perhaps entirely.

Three larger wind turbines (Northwind 100B, 100 kW) have been added to the island. Now when there’s too much wind power, it will be used to produce hydrogen though water electrolysis. The hydrogen gas will then be stored in tanks and tapped when wind energy is not creating enough power for the community. A hydrogen converter generator will convert the stored hydrogen to electricity, producing much fewer greenhouse gas emissions than diesel.

Technical components of the project include a **hydrogen electrolyser**. Hydrogen is created by the electrolyser through the process of electrolysis using water and electricity to create oxygen and hydrogen gases. Oxygen is released into the atmosphere while hydrogen is stored in high-pressure cylinders to be used as an energy supply. The WHD project’s first hydrogen production was achieved on December 12. Other components include the **hydrogen genset**, and an **energy management system (EMS)**, which will provide all automatic control and monitoring of the wind turbines, the electrolyser, genset, hydrogen storage, and the diesel plant to ensure safe and reliable delivery of energy to homes and businesses in Ramea. The EMS is the computer system which dispatches each piece of equipment associated with the WHD Project. The EMS was designed and is being built by Hydro and Nalcor Energy will retain all intellectual property rights to this critical piece of software.

A 40-metre meteorological tower was installed near the new wind turbines. The tower provides highly accurate meteorological data for wind speed, direction, temperature and humidity into Nalcor’s Energy Management System to optimally dispatch different energy sources. This data will be stored on a central server and will be very useful during the research phase.

System integration entails the connection of the cables and piping that link the wind, hydrogen and diesel equipment together, and includes a safety instrumented system (SIS). The SIS consists of five safety stations that monitor the entire hydrogen system and will alert the operators of any problems with the equipment. In addition to the SIS there is numerous safety controls designed into the hydrogen mechanical system such as pressure regulating and relief valves and a specifically-designed vent stack.

Electrical switchgear interconnects all new equipment to the existing diesel plant 4160V bus. The switchgear provides Hydro with the ability to isolate the new equipment from the existing equipment if any problems occur on the system.

A network communications system will relay protection and control data to ensure the reliable operation of the WHD system. The communications system consists of network equipment; optical fiber and copper linking the diesel plant, new wind turbines, electrolyser, hydrogen genset, SIS and the meteorological tower. The new equipment allows Hydro to gain access to, and control, this remote site from its Energy Control Centre and Network Management Centre in St. John's; similar to other generation assets on the provincial electricity grid. A wireless radio link is also present providing communications between the Ramea diesel plants to Frontier Power's wind farm.

While the localized role is small, the provincial, regional, national and international potential for export is promising in the medium term. Nalcor hopes its wind-hydro-diesel energy technology can be commercialized and exported worldwide. Newfoundland alone has nearly two dozen isolated diesel-dependent electricity systems. If successful, similar systems could have application in any other of Canada's 100+ isolated communities. Globally there are many hundreds more isolated off-grid communities, many of which rely heavily on petroleum based energy or have no major energy system. The future goal would be commercialization of the energy management system needed for integration.

3.2 New Brunswick - PowerShift Atlantic

PowerShift Atlantic (much of this discussion is taken directly from www.powershiftatlantic.com) is a collaborative research project led in partnership by Natural Resources Canada through the Clean Energy Fund, New Brunswick Power, Saint John Energy, Maritime Electric, Nova Scotia Power, New Brunswick System Operator, the University of New Brunswick, the Government of New Brunswick and the Government of Prince Edward Island.

The four-year $32 million project, which started in 2010, focuses on finding more effective ways of integrating wind energy to our electricity system in the Maritimes. While a clean renewable energy source, wind is more unpredictable and irregular than traditional generation. One solution to working with the variability of wind generation is to find ways to shift the times that energy is delivered to homes and commercial buildings when it isn't needed. The goal of the project is to experiment and find acceptable ways to shift the time that electricity flows to homes and businesses, with minimal or no disruption or inconvenience to the customer.

The partnership has formed an innovative technology cluster to provide ancillary services for wind integration. This ancillary service will be carried out by shifting commercial and residential loads. The primary demonstration objective is to determine if load shifting can provide for more economical integration of wind rather than expensive supply side options to be built in the future. The scope of the project is significant with load shifting in up to 2000 sites. The primary objectives of the project are:

- Evaluate if load control is a cost effective and reliable ancillary service to dispatch net requirements.
- Evaluate load control performance in response to measured and forecasted wind power.
- Evaluate the customers' role and their acceptance of utility control for the purposes of renewable energy integration.

The PowerShift Atlantic Research Project concentrates on finding acceptable ways to remotely adjust the amount of electricity that flows to homes and businesses, with minimal or no disruption or inconvenience to project participants, at times when it is not required by the customer. The Residential Research aspect is conducted by Saint John Energy, Maritime Electric and Nova Scotia Power. Specific criteria are set by the various utilities and an initial group of participants is selected. The utilities determine if potential participants have electric appliances in their home that qualify for the program. Participants who qualify and agree to join the program have a device installed on a qualified appliance.

The Commercial Research Program will be conducted at Nova Scotia Power and New Brunswick Power. Commercial customers will be approached by their local utility to determine whether they are interested in participating in the research program and whether they qualify for the project. Commercial customers will be required to have a qualifying end use (for example, refrigeration/freezer storage), as well as a suitable energy load that can be shifted, based on the availability determined by the customer. Through a mixture of required hardware and software, the utility will be able to remotely control certain end uses at the customer's location to help integrate wind energy more efficiently into our electricity system in the Maritimes.

The primary academic partner is the University of New Brunswick's Sustainable Power Research Group, led by Dr. Liuchen Chang in the Department of Electrical and Computer Engineering. The group conducts research and training in the areas of distributed power generation, renewable energy conversion, power electronics, electrical machines, communications, and advanced control systems. The current research activities include development and demonstration projects of distributed power generation based on wind, photovoltaic, small hydro, micro-gas turbine and fuel cell systems.

Shifting power demand has regional and global application, and could bring major change to the Maritimes and to North America as a whole, and offers the potential to bring more wind energy to North America.

3.3 Nova Scotia – Tidal In-Stream Energy Conversion

Nova Scotia has a world class tidal energy resource in the Bay of Fundy, with significant resources located in other areas of the province. Research from the California-based Electric Power Research Institute published in 2007 identifies the Bay of Fundy as the best site in North America for tidal power generation. An estimated 14 billion tonnes of sea water passes through the Minas Passage on each tide cycle creating currents in excess of 5 metres per second. Recently, local scientists have estimated that potentially 2,000 MW of tidal energy could be safely extracted from the Minas Passage alone.

Tidal in-stream energy converters are the preferred technology for the generation of electricity from tidal energy resources because heavy civil works such as dams, and the significant environmental effects that accompany them, are not required. In-stream devices convert the kinetic energy of moving water to electricity, but with a higher capacity factor than wind turbines. Another advantage of tidal energy conversion is the predictability of the electricity that is generated; tides are predictable therefore the energy that can be extracted from them is also somewhat predictable, making it easier for transmission utilities to integrate tidal power with electrical grids.

Aside from being a potentially useful source of electrical generation, the development of tidal in-stream energy converters holds significant promise for future economic benefit to the parties involved in its successful commercialization. As with efforts underway in the United Kingdom, the proponents of Nova Scotia's nascent tidal industry hope to see socio-economic benefits to Nova Scotia beyond the electricity sales generated through the installation of commercial arrays in the Bay of Fundy.

Two Offshore Energy Research Associations were established by the Province of Nova Scotia in 2006 – the Offshore Energy Environmental Research Association (OEER) and the Offshore Energy Technical Research Association (OETR). In 2008, the independent, non-profit Fundy Energy Research Network (FERN) was established at the Acadia Centre for Estuarine Research at Acadia University to "*coordinate and foster research collaborations, capacity and information exchange to understand the environmental, engineering & socio-economic factors associated with tidal energy development in the Bay of Fundy".* In 2009, the Province enabled the formation of the Fundy Ocean Research Centre for Energy (FORCE). FORCE is a non-profit organization that is funded by the Government of Canada, the Province of Nova Scotia, Encana Corporation, and member developers. FORCE has established a demonstration site in the Minas Passage, an observation facility near Parrsboro, and will complete the installation of subsea transmission cables with grid connection in 2012.

In 2008, OEER commissioned a Strategic Environmental Assessment (SEA) that examined potential effects of tidal energy extraction in the Bay of Fundy. The SEA made recommendations intended to ensure that tidal energy developments would maintain the ecological integrity of the Bay of Fundy and environs, and make a "*positive contribution to the social, economic and cultural well-being of Nova Scotia as a whole and of rural communities in particular*". The report also recommended that demonstration trials be conducted for both large and small-scale technologies that could be deployed in a variety of locations.

The report reinforced the need to ensure that other marine resources and users are not adversely affected, and further emphasized the need for research to examine long-term, cumulative and far-field effects of commercial operations. With respect to the devices, the report recommended environmental monitoring programs and the establishment of threshold criteria to define the circumstances under which devices must be retrieved.

Subsequent to the SEA report, the Government of Nova Scotia made the development of tidal energy a component of its Renewable Electricity Plan and established FORCE as a demonstration site for large-scale in-stream tidal energy technology. There is also a strong commitment by Nova Scotia to support community-based small scale tidal energy conversion. These two elements are discussed separately, below.

Large Scale Generation: The Minas Passage

OEER has been the primary funder of tidal energy research in the Bay of Fundy. OEER has facilitated investigations into the impacts of tidal energy devices on the environment of the Bay of Fundy, as well as the impacts of the Bay of Fundy on tidal devices deployed in its rather harsh environment.

Determining the potential effects associated with the extraction of tidal energy from the Bay of Fundy requires information from a variety of scientific and technical disciplines. Since their inception, OEER, FORCE and FERN have initiated research projects to begin filling gaps in the understanding of the Bay of Fundy as a natural system and how tidal energy converters may impact that system. Research programs funded by these organisations focus on hydrodynamics, geophysics, biology, ecology, and cable installation and monitoring.

Research investigations have been collaboratively conducted by institutions such as Acadia, Dalhousie, St. Mary's, the Nova Scotia Community College and the Bedford Institute of Oceanography, with funding from Federal and Provincial governments through FORCE and OEER and with the close interaction of device and site developers.

Environmental effects monitoring programs are in place to examine changes to the acoustic environment, benthic habitat, fish movement, lobster presence, marine mammal and seabird behaviour and presence in the Minas Passage.

Concurrent with this research is the device-oriented RD&D that is undertaken and funded by the technology developers. To date only the Open Hydro device has been deployed at the test site by Open Hydro and its utility partner Nova Scotia Power, although three other technology developers hold berths and are planning demonstration projects.

Small Scale Generation

Several locations within the Bay of Fundy have been identified as having strong potential for electricity generation on a smaller scale, including Digby Gut and passages between Digby Neck, Long Island and Briar Island, all in Digby County. A community-based company, Fundy Tidal Inc., has been pursuing tidal energy development in these and other areas since 2007. With the introduction of the Nova Scotia Community Feed-in Tariff (ComFIT) program in 2011, Fundy Tidal Inc. now has a financial mechanism that will allow development to proceed.

Research specific to Fundy Tidal's proposed devices and deployment sites ongoing with funding provided by NSERC and OEER/OETR. Work completed to date includes assessment of tidal resource, modelling of tidal arrays in Grand Passage and deployment of a device in Grand Passage. OEER/OETR also funded a gap analysis for small scale in-stream tidal technology earlier this year to identify sites suitable for device demonstrations, device efficiency, and an assessment of environmental impacts associated with the devices.

Currently, an assessment of the in-stream tidal energy resources in Southwest Nova Scotia (Shelburne, Yarmouth and Digby Counties) is being conducted by Acadia University in collaboration with Dalhousie University, the Nova Scotia Community College and Fundy Tidal Inc. Field work will include deployment of Acoustic Doppler Current Profilers (ADCP) and input from local fishermen and communities. All research and technological developments included in the work scope will include the training of students in Marine Renewable Energy.

According to OEER, "the Resource Assessment will incorporate all phases of small scale ocean renewable energy development for Southwest Nova Scotia for both pilot and commercial scale developments. Deliverables from the project will include charts with information on current water use and areas of high velocity currents, recommendations for ADCP deployment locations and tide corrected high resolution bathymetry in GIS and latitude, longitude and depth formats. The project will take place from November 2011 – April 2012".

3.4 Prince Edward Island – Wind/storage

PEI has no conventional energy resources of its own and as a result has developed its capabilities in wind energy, clearly one of its most valuable natural resources. In its last two provincial Energy Strategies (2004 and 2008) and in its most recent Energy Accord (2011), wind has played a major role in PEI's goals of reducing and stabilizing energy rates and in increasing energy security. The PEI Energy Corporation is responsible for developing wind energy projects on PEI. Beginning in the 1980s it began to develop a wind energy test site, which grew into what is now known as the Wind Energy Institute of Canada (WEICan). WEICan strives to advance the development of wind energy in PEI and across Canada through research, testing, demonstration, training and collaboration.

Recently, WEICan received funding to develop a Wind Energy R&D Park with a utility-scale energy storage system. The priority will be to demonstrate the integration of a storage system with a small wind farm on a weak distribution system. The project will feature 5 DeWind Co, D9.2 wind turbines - generating capacity of 10 MW, a utility-sized electricity storage system and the examination of grid integration technologies to increase the economic viability of intermittent electricity generation. DeWind, a wholly-owned subsidiary of Daewoo Shipbuilding and Marine Engineering Co. Ltd. will be supplying the wind towers through another subsidiary, DSTN Trenton, a Nova Scotia company. The project represents a milestone for DeWind: the first DeWind turbines installed in Canada and the first DSTN towers supplied for DeWind turbines.

The Federal Clean Energy Fund contributed $12M and the Province of PEI contributed $12.6M as a repayable loan. The award will allow for the sustainable operation of WEICan through electricity sales to partner Maritime Electric. The project will investigate how energy storage can be utilized to maximize renewable energy production while reducing instability of the provincial electrical grid. The Park will be made available for wind energy research and development, making its data available for research projects and as a test bed for auxiliary technology concepts for wind turbines and wind farms. Support, through this project will also further WEICan's research, development, and demonstration in the small wind sector.

The new Wind Park will allow WEICan to expand its research mandate and provide sector-enabling support helping manufacturers, governments, and academia evaluate and improve their technologies. The project will offer system operators and utilities a test bench environment for wind and storage systems that currently do not exist. The availability of the project for research purposes will allow WEICan to expand its research role into:

- Optimization of wind forecasting and forecasting methodologies using real-time data
- Grid integration issues
- Continued testing, research, development, and demonstration of small wind technologies

- Storage facilities to mitigate energy intermittency
- Storage performance with respect to reliability and economics.

WEICan presently collaborates internationally and with companies in Canada and the Atlantic region. The demonstration involves a number of collaborators from Maritime Electric and the New Brunswick System Operator. Seaforth Energy's AOC 15/50 Wind Turbine is being commissioned at WEICan for "Testing Leading to Certification". Academic research collaborators include the Sustainable Power Research Group (SPRG), Directed by Dr. Liuchen Chang, UNB. Focusing on renewable energy systems, particularly wind energy conversion systems, SPRG has grown into one of the largest academic research groups for renewable energy Canada. The Canadian Wind Energy Strategic Network (WESNet), also led by Dr. Liuchen Chang, includes leading researchers from 16 Canadian universities in six provinces, NRCan and Environment Canada, the Canadian Wind Energy Association, utility companies, wind sector businesses and WEICan. Holland College, located on Prince Edward Island, offers a 9 month Wind Turbine Technician program. The program is certified by the internationally recognized BZEE Education Centre for Renewable Energies in Germany. Holland College and WEICan operate a training tower located at WEICan's North Cape site and provide wind tower climbing and rescue training to their students. Dr. Yves Gagnon, KC Irving Chair in Sustainable Development at the Universite de Moncton is Vice Chair of the WEICan Board.

Potential exists for new collaborative relationships with the Dalhousie Research in Energy, Advanced Materials and Sustainability (DREAMS) program, Directed by Dr. Mary Anne White and the newly created Renewable Energy System's Lab, in the Faculty of Engineering at Dalhousie, directed by Dr. Lukas Swan.

The WEICan project exemplifies positive benefits to government, academic, and industry stakeholders in Atlantic Canada; WEICan has become fiscally sustainable, regional academics can benefit from and contribute to the success of the project, regional industry earns revenue and benefits from services, and governments achieve goals; a win – win – win situation.

SECTION 4 COMPONENTS OF AN EFFECTIVE RD&D PROJECT

The initial discussion in this Section steps away from the direct topic at hand to review more generic characteristics that have come to be recognized as components that constitute effective high quality R&D projects. Following this, the components are applied to the four key clean energy projects to test the parameter's fit. Prior to a discussion of the parameters that "make up" good RD&D projects, it is important to recognize the stages of the innovation chain, and what project stage appears to broadly meet the needs of AEG stakeholders.

Using the Canada Revenue Agency's Scientific Research and Experimental Development (SR&ED) program qualification parameters, the early stages of innovation can be defined as:

- Basic research – research to advance scientific knowledge without a specific practical application in view
- Applied research - research to advance scientific knowledge with a specific practical application in view

- Experimental development - to achieve technological advancement to create new materials, devices, products, or processes, or improve existing ones

The Atlantic Energy Gateway (AEG) initiative aims to facilitate development of the Atlantic renewable energy sector by fostering collaboration, common understanding, and communication among governments, and between governments and the private sector, to maximize and expedite the development of renewable energy sources in the region. The AEG will foster regional cooperation and collaboration in the planning and operations of the Atlantic electricity sector, which will facilitate the development of clean and renewable energy in the region, thereby displacing GHG-emitting sources of electricity.

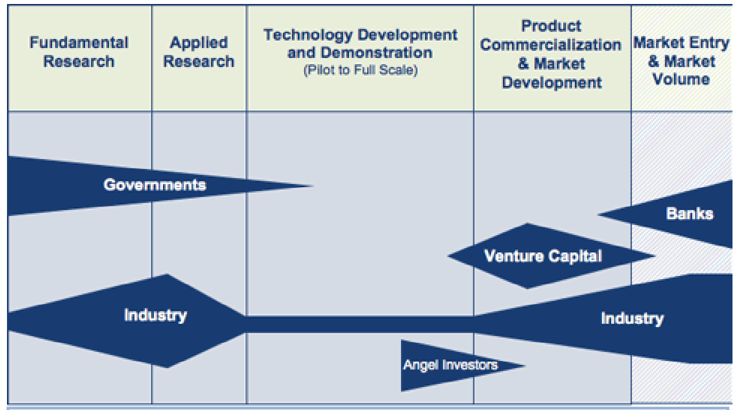


Figure 5: Innovation chain and funding (Sustainable Development Technology Canada)

In keeping with the objectives of the AEG, the development of the region's clean energy resources entails a focus toward the "middle" of the innovation chain. Indeed, the four projects previously presented in Section 3 range from applied research to pre-commercial demonstration, essentially in the middle of the innovation chain noted above. This is not to say that pure fundamental research should not be supported. A number of financial programs such as NSERC are in place to do so, and these will be discussed later in Section 7.

Members of the SLR/Maxis team have been involved in the study of the topic of R&D in a number of sectors throughout Atlantic Canada. The clean energy projects noted above share similar characteristics to other RD&D approaches deemed successful in other sectors. With reference to Atlantic Canada's offshore petroleum industry, extensive study has focussed on assessing methodologies to identify effective applied R&D strategies, in part to assist industry in meeting stringent Atlantic and Nova Scotia Accords requirements of offshore operators respecting R&D commitments and expenditures. Effective RD&D projects work when:

- The region has a significant resource base (has **local relevance**)
- There is a realistic chance of **use-ability and innovation**
- **Priorities** are established and recognized
- They meet a **market need** (international relevance, export potential)
- Industry needs are front and center; **industry is engaged** as an active participant
- **Government needs / objectives** and policies are **aligned**
- Local/regional industrial and academic **capacity** exists to provide solutions (facilities, Highly Qualified People (HQP))
- Industry and government needs are **matched** with local RD&D capabilities to create regional value

- **Adequate funding** is maximized by leveraging (industry, government and academia; programs without matching or repayable conditions are often ineffective)
- **Global** links and international **alliances** are struck when relevant (recognize that other area of the world might be more advanced in certain subsectors)
- Plans and structures allow open **communication** and information sharing (effective means of internal and external communication, as well as keeping data current)

The components above allude to partnering and cooperation between government entities, the private sector, and the academic community. Depending on the size and global reach of the application of technologies and projects in question, cooperative partnerships are valuable on a local, regional, national, and international scale. Effective RD&D projects are often supported by an organizational structure that includes a central body to play a "fourth pillar" facilitation role, supported by a "with or without walls" working and assessment group.

The four projects highlighted in Section 3 align well with these parameters on the framework of effective partnering (Table 2). In conclusion this basis of project assessment can be applied to future potential clean energy projects approved under the AEG.

Table 2 – Attributes of the Four Major Projects

	Ramea Wind Energy	Power Shift Atlantic	Tidal Energy	Wind Storage
Local Relevance	✓	✓	✓	✓
Use-ability and Innovation	✓	✓	✓	✓
Established Priorities	✓	✓	✓	✓
Market Need	✓	✓	✓	✓
Industry is Engaged	✓	✓	✓	✓
Consistent with Government Objectives	✓	✓	✓	✓
Local/Regional Academic Capacity	✓	✓	✓	✓
Matching (Industry, Government and Academic Partnerships)	✓	✓	✓	✓
Adequate Funding	✓	✓	✓	✓
Global Alliances (if required)			✓	
Communication and Information Sharing	✓	✓	✓	✓

SECTION 5 AREAS THAT MAY BENEFIT FROM INFORMATION SHARING AND REGIONAL COOPERATION

All four Atlantic Provinces have varying levels of interest in, or in advancing, energy/electricity generation from aspects of wind energy, biomass, biofuels, marine renewable energy (primarily tidal, with wave/current technologies noted), small hydro, and to a lesser extent solar and geothermal sources. The challenges and immediate priorities differ somewhat locally within the region.

Determining detailed clean energy priorities and specific related projects are beyond the scope of the SLR/Maxis team. Areas of shared interest are, nevertheless, evident within the findings of this report. These broad areas can potentially form the basis of more detailed technical review to determine the merits of pursuing related regional partnering projects.

5.1 Offshore and Onshore Wind (larger turbines)

The entire region has an interest in advancing offshore wind but recognize that the prospect of large scale development is not an immediate priority and would depend on an ability to compete in export markets. Utilities and governments can remain abreast of international developments and communicate with each other through the AEG structure proposed in the next section.

A regional interest exists in ongoing wind energy development, but concerns voiced primarily in NB and NS are related to the challenges in wind integration and balancing. Current demand side management work under PowerShift Atlantic is designed to be a means of addressing this, and further studies may well be required. PowerShift complements storage options, which are a second means of dealing with the same issue: integrating the highly variable wind generated power.

The WEICan Wind Energy R&D Park offers wind energy infrastructure for testing and demonstration. The institute collaborates internationally and with companies and researchers in Canada and the Atlantic region. PEI offers a wind energy technician program at Holland College. UNB and University of Moncton collaborate presently and Dalhousie can collaborate through researchers in Science, Engineering and Management. Dalhousie’s DREAMS program offers top materials researchers and a funded supply of the undergraduate students to post-Doctoral Fellows that they supervise. The Institute for Research in Materials and a proposed Clean Tech Research Chair offer further potential. NS, NB and PEI have considerable experience in introducing wind energy into the grid, and two Nova Scotia companies produce wind towers and/or turbines and blades (DSME and Seaforth Energy).

Limitations on NL’s grid for additional renewable energy given the abundance of hydro power have detracted from a need to develop large wind farms. Yet the province has identified wind as an important clean energy source, and has commenced studies focussed on road-mapping the impacts of harsh (cold) environments on turbine performance and transmission.

The entire region is affected by harsh environments, and in some cases poor weather has caused the shut-down of turbines in Atlantic Canada (e.g. Suez Energy’s NB Caribou Mountain ice and cold issues in 2011 and 2012), and internationally. The region would benefit from shared insight and regional partnering to address the international challenges associated with the negative impacts of high winds, cold and ice of large (and small) turbines. Further, improved accuracy of weather/wind forecasting on an hourly basis would benefit the industry as a whole, and clearly an interest exists. In July 2010 NL hosted a “Wind Energy Development in Harsh Environments Workshop.” Over 120 people participated, 10 of whom were representing organizations from the other three Atlantic provinces: NB (UNB, NSERC Atlantic, NRC-IRAP); NS (Stantec Consulting, Emera, Offshore Energy Research Canada, Nova Scotia Power), and; PEI (Island Technologies Inc, Frontier Power Systems).

The Atlantic Region can and does benefit from expertise at the University of New Brunswick's Sustainable Power Research Group, Directed by Dr. Liuchen Chang; Dalhousie University's Renewable Energy System's Lab, Directed by Dr. Lukas Swan; and the University of Moncton's expertise under Dr. Yves Gagnon, KC Irving Chair in Sustainable Development. Combine the expertise of participants, researchers and stakeholders for the Ramea Wind Energy Project RD&D with the current active enabling technology such as the Available Wind Power Forecasting, which was developed by AMEC Americas Limited, and efficient enabling technologies will increase the effectiveness of wind power locally, and ultimately, regionally. The net power forecasting, of which a portion is currently used as a tool by NTV local weather forecasts, could provide the capacity for a Pan-Atlantic wind forecasting service. Provision of regionally-based wind forecasting service could benefit the overall capacity for the generation and distribution of wind energy. This in turn, could also be redesigned or modified to provide the capacity of wind fluctuations and power forecasts regionally for tidal and/or wave projects. PEI's WEICan site, with an added recent focus on wind energy storage and grid integration is as well consistent with the priorities of NB and NS. Indirect added work in coatings and turbine repair can also benefit the region as a whole.

In terms of smaller wind applications, NL is regionally unique in that a number of communities are off-grid, and hence interested in solving the challenges and expense of diesel generation in these communities. NL is not unique in its interest in small wind turbines for a number of small technology applications. Interest exists in Nova Scotia in the area of vertical axis turbines suitable for agricultural and rural environments. Again, one NS based company manufactures a 3.7 kW and a 50 kW turbine, and is now developing a 50 kW turbine that will operate at lower wind speeds.

5.2 Additional Demand Side Management Studies

New Brunswick and other provinces could benefit as a whole implementing a provincial and regional Powershift using respective predominant clean energy sources. Each province would be able to provide a certain capacity to the Powershift system by accommodating the intermittent nature of wind power for instance. Currently communities in NB, PEI and NS have been contributing to the Powershift program, which focuses on the capacity of a collaboration between smart grid technologies, customer loads, and intermittent renewable energy sources from the respective provinces.

The region may learn from the experience of others when it comes to smart grid technologies. For example, in response to opposition to nuclear power in the wake of the Fukushima disaster, South Korea's plans to install smart meters in half the country's households by 2016, which could cut electricity consumption equivalent to the cost of one nuclear power plant.

5.3 Energy Storage Technologies

Electricity storage is an increasingly important component of renewable energy use. Within the Atlantic region, academic capacity expertise exists in electricity storage, fuel cells and battery technologies. The Wind Energy Institute of Canada (WEICan) is advancing the development of wind energy across Canada through research, testing, demonstration, training and collaboration. The new 10 MW Wind Energy R&D Park will investigate and demonstrate how energy storage can be utilized to maximize renewable energy production and help to stabilize the electrical grid. Again, potential exists to build on the current collaborative relationship with Sustainable Power Research Group at UNB. Similar to the discussion on wind, collaboration potential exists with the Dalhousie Research in Energy, Advanced Materials and Sustainability (DREAMS) program. The purpose of DREAMS is to train a cohort of research scholars (Masters and PhD students, undergraduate summer research students and postdoctoral fellows in Chemistry, Physics and Mechanical Engineering) at Dalhousie University who will address important aspects of energy production, storage and sustainability. Furthermore, the newly created Renewable Energy System's Lab, within the Faculty of Engineering at Dalhousie, offers electricity storage expertise for wind energy and transportation needs. Dr. Jeffrey Dhan at Dalhousie and Dr. Peter Pickup at Memorial are both recognized as world experts of Energy Storage and Fuel Cells.

5.4 Small Hydro

While a moratorium on hydro development remains in effect on the island portion of NL, Nalcor is looking at small-scale hydro development in Labrador, and studies have been completed over the years looking at a number of small hydro sites on the island. NB's Blueprint points to river hydro as having potential for its Large Industrial Renewable Energy Purchase Program. The NBDOE has recently released hydro resource maps showing the technical power potential for small hydro in the province (http://www.gnb.ca/0085/Hydro_Conventional-e.asp).

While penstock-type small hydro might not be considered RD&D, the provinces of NL and NB might benefit from shared effort in small hydro development. Further, emerging smaller tidal technologies (such as run-of-river/kinetic devices) can have application in river settings (see Tidal discussion) and might be considered, as an AEG area of interest, in conjunction with ongoing work in NS. It is of added interest that Seaforth Energy, discussed previously under wind regarding their manufacturing of the AOC 15/50 turbine in Dartmouth, also owns and operates an 850-kW run-of-river hydroelectric facility in New Germany, Nova Scotia under subsidiary Morgan Falls Power Corporation.

5.5 Tidal

While Nova Scotia has the largest accessible tidal resource in Atlantic Canada, New Brunswick and Newfoundland and Labrador also have significant resources. The RD&D work currently underway in Nova Scotia, both for large and small-scale tidal conversion, presents a tremendous opportunity for the entire Atlantic region. Collaboration among researchers at government, industry and academic institutions in Nova Scotia, PEI, New Brunswick and Newfoundland provides opportunities for innovation that will assist in advancing the sector towards commercialization. Research capacity in science and engineering at the region's academic institutions and government labs, coupled with world class marine research infrastructure at the region's research facilities, along with a vibrant marine industry could all contribute to making Canada's marine renewable energy sector highly competitive in the global marketplace.

Halifax and St. John's are both centres of oceans excellence. The Halifax Marine Research Institute brings together five Federal government research labs (Defense Research and Development Canada (DRDC); DFO; Geological Survey of Canada-Atlantic; NRC Institute for Marine Biology; Environment Canada - Atmospheric Science and Technology), Maritime Universities along with Nova Scotia companies involved in the oceans tech sector. St. John's offers the Marine Institute, the Institute for Ocean Technology at the NRC, the Centre for Cold Ocean Resources Engineering (C-CORE), Memorial University and a variety of ocean technology companies. Outside of these centres, expertise exists in New Brunswick's Huntsman Marine Science Centre in St. Andrews and at UNB and UPEI.

Small tidal device technologies, such as those in development by Fundy Tidal Inc. in southwest Nova Scotia, may be employed in Atlantic rivers, and may therefore have broader application throughout the region. The effects of ice, corrosion, and debris on such applications may need considerable study. Smaller more flexible technologies appear to have application in settings where small wind and small hydro are under consideration, thus serving remote, off-grid communities that presently rely on unsustainable diesel-electric generator sets.

5.6 Biomass with Focus on Pellets

While province by province challenges exist, interest in the use of biomass for heat/combined heat/power and electricity generation is of interest across the region. The forest industry is a significant regional employer. Environmentally sustainable development of biomass and related products holds the potential to offset challenges in the global pulp and paper industry that are affecting Atlantic Canada.

Bioenergy is a component of the PEI's Renewable Energy Initiative, and a similar program exists in NS. Researchers at UPEI and the PEI Departments of Agriculture and Forestry along with private research companies (e.g. Atlantec BioEnergy) could collaborate with NB and NS researchers on the concept of bio-refineries.

The area of wood pellets is not considered RD&D, and a number of companies throughout Atlantic Canada produce wood pellets, and the Government of NB has expressed an interest in developing and implementing supporting policies to optimize the energy output from wood based biomass resources with a specific focus on pellets. The development of pellet standards, in conjunction with similar and current efforts in the U.S., is cited as an area of potential regional cooperation. Academic expertise in biomass and biofuels exists throughout the region to support partnering initiatives.

The primary use of pellets in Atlantic Canada is for heat generation. In terms of electricity generation (through discussions with government and industry representatives), pellet use is common in areas of Europe. Standard wood pellets cannot be exposed to the elements (wet weather) so large supplies must be stored in sheltered locations. Wood pellets must also be pulverized for use with coal in electricity power plants (source: personal discussion). Other challenges exist with the high ash content of pellets that are produced from agricultural biomass.

With respect to RD&D, new advancements are being made with black pellet technology. Efforts of a number of small Nova Scotia based companies (Bio Vision Technology Inc. and B. W. BioEnergy Inc) along with large global energy companies, in particular Sweden's Vatenfall AB. These companies are working on perfecting the "torrefaction" process that thermally treats (chars) the wood to a charcoal-like substance. These pellets hold the potential to replace coal, or be more easily combined with coal, providing a more environmentally friendly energy source, made up almost entirely of biomass and waste wood, which can be derived from local resources. The technical pros and cons of new pellet technologies appears to be an area of shared area of RD&D interest. It has been suggested that a demonstration project to test the effectiveness of new biomass technologies to produce electricity might be a regionally beneficial project.

5.7 Power Purchase Agreements (PPAs), Independent Power Producers (IPPs), Community Involvement and Large Industry Initiatives

A detailed review of all programs introduced by each province to encourage participation in electricity generation through PPAs, IPPs, Comfits, etc., is beyond the scope of this report. Suffice to say that all four Atlantic Provinces have varying degrees of experience, both positive and negative, in engaging communities, organizations and industry outside of utilities in the supply of electricity. According to officials within the Government of NL, the Government still operates under the policy that Nalcor is responsible for coordinating all hydro developments and all wind developments on Crown land. In its procurement of grid wind projects in the past, Nalcor has released RFPs to solicit projects from IPPs, and did the same for small hydro in the 1990s. Nalcor is open to working with proponents of community wind projects in the isolated diesel communities using diesel-fuelled electricity generation. However, the projects would have to be developed in partnership with Nalcor. There are no plans for any standard offer or feed-in tariff program.

An AEG based roundtable in which the core discussion focuses on strategies that have worked, and those that have not, might be beneficial for the region as a whole.

Matching of regional of strengths and priorities with the region's R&D capacity (Figure 6), reveals areas of potential cooperation to advance clean energy throughout the region and beyond. There exists, for example, broad yet regionally varying interest on the part of all four provinces in the areas of: harsh environment impacts and forecasting; small wind applications; biomass; and energy storage. This matches, again to a varying degree, academic capacity, private sector involvement and ongoing related studies.

These observations are important considerations when developing ideas for potential projects of interest, and regional cooperative partnerships. Each province can bring to bear shared as well as unique interests and capacities for the benefit of the region as a whole.

A tabular format is provided (Table 3) to summarize what in essence the overall point of this report, and that is: (1) What are some shared areas of interest and (2) what potential partnerships can be struck to foster regional cooperation and collaboration in the planning and operations of the Atlantic electricity sector, and facilitate the development of clean and renewable energy in the region.

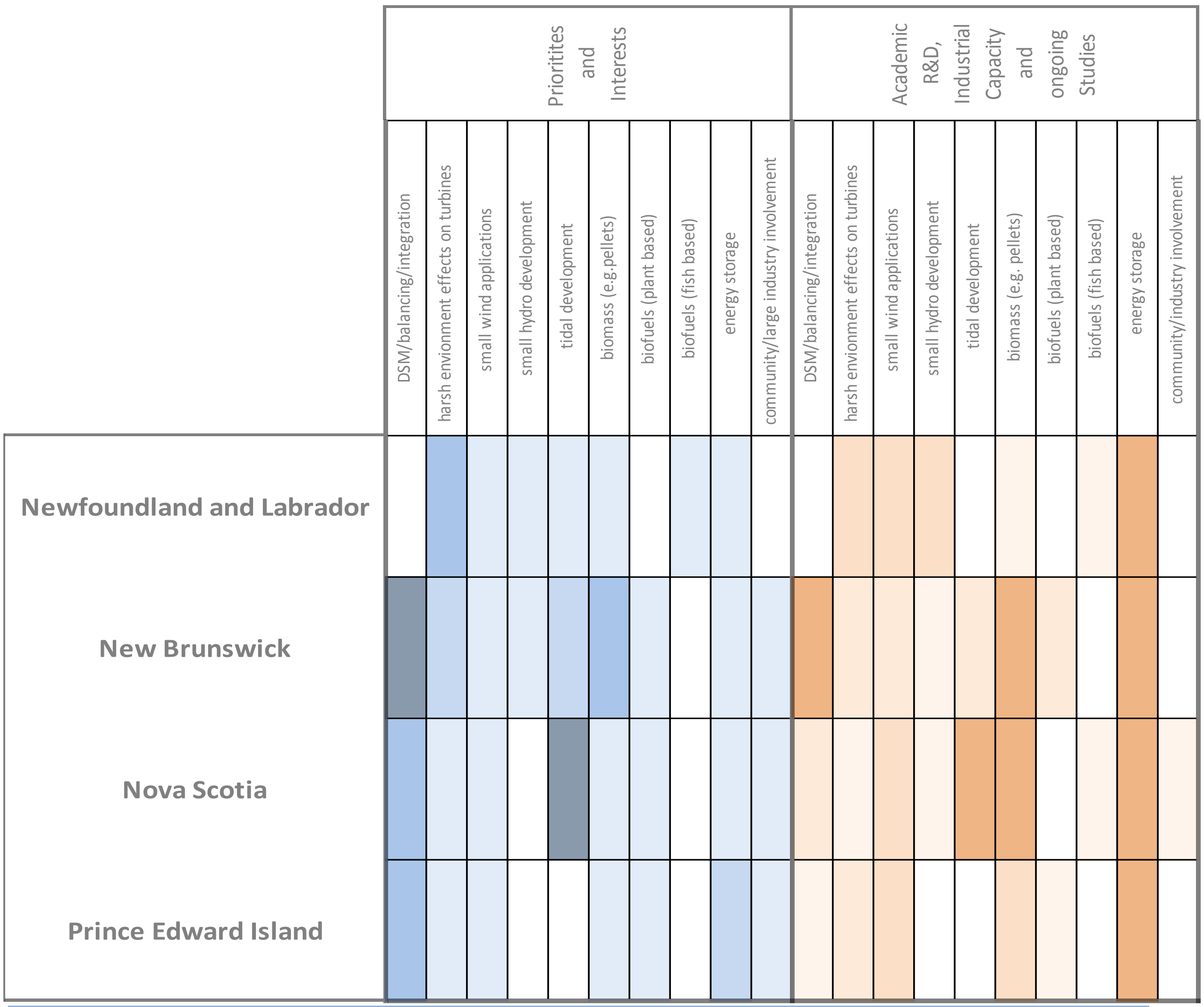


Figure 6 – Priorities and Capacity by Province

Table 3 – Shared Interests and Potential Partnerships

Area	Topic of Interest	Lead Government organizations (in addition to NRC/Canmet, ACOA)	Utility Lead	Private Sector Engagement	Key Academic Participants/Partners
Wind (onshore and offshore)	Harsh environment impacts, advanced weather forecasting, resource mapping, offshore wind interest, application of technologies from other sectors (e.g. aerospace)	NL-DNR, NB-DOE, PEI-WEICan. Other international bodies	Nalcor, Maritime Electric	AMEC. NL road-mapping consultants, MDS-PRAD Tech, Vector Aerospace, WesTower, Extreme Ocean, select wind farm owner/operators (e.g. Suez)	Y. Gagnon/UM, Wind Energy Strategic Network, DREAMS, IRM/Dal, L. Swan/Dal
Small Wind	Turbine technologies, storage application off-grid, application for agriculture, rural areas, households and small businesses	PEI-FEMA, WEICan	NSP re impacts on distribution systems	Seaforth Energy, Frontier Power	L. Chang/UNB, NS Agricultural College, T. Iqbal/MUN,
Demand Side Management	Continued studies and approaches in DSM, balancing of renewable energy, investigating other international regimes experience	NB-DOE	NB Power with all provincial utilities	Large industrial. International bodies	L. Chang et al/ UNB, M. ElHawary/Dal
Energy Storage and converters	Challenges with storage, hydrogen, wind to hydrogen, fuel cells, compressed air, application off grid, grid stabilization	NB-DOE, WEICan, Canadian Hydrogen and Fuel Cell Association (CHFCA)	NB Power with all provincial utilities	Atlantic Hydrogen Inc, custom Research, Elotech, Knowcharge Inc., Yava Technologies, 3M Canada	L.Chang/UNB, S. Eisler/UNB, P.Pickup/MUN, J. Dahn/Dal, J. Ghouili/UM, DREAM/Dal
Small Hydro	Small scale off-grid hydro, large industry small hydro development, small tidal device application, environmental/fisheries impacts	NL-DNR	Nalcor, NSP	Seaforth/Morgan Falls, Fundy Tidal	A.Hay/Dal, authors of studies completed for utilities
Marine Energy (tidal/wave/current)	Regional application following NS lead, small tidal technology applications regionally and in run-of-river settings, wave technologies, off-grid applications, technical challenges, environmental & system modelling and testing	NS-DOE, DFO	NSP/Emera	Fundy Tidal, Oceanic Consulting, Grey Island Energy/Genesis Center (MUN), Stantec/JWEL,	NB Huntsman Center, BIO, M. Graham/CONA, HMRI, MUN/Marine Institute, IOC, C-CORE, R. Karsten, A. Redden., R. Daborn et al/Acadia
Biomass/pellets	Biomass from forestry and agriculture, biomass conversion, short rotational plants/crops (willows), new pellet technology such as torrefaction for RD&D focus, application for heat, combined heat and power, and electricity generation and cogeneration. Investigate demonstration projects	NS-DOE/NB-DOE	NSP – investigate demonstration project for pellets / black pellets. Perhaps build on CEF funded biomass and coal co-firing demonstration project	major forestry companies, woodlot harvesters, sawmills, current pellet manufacturers throughout the region, BW BioEnergy, Vatenfall, Envirem Technologies, BioEnergy Inc, LST Energy, West Nova Agro	UNB, NBCC, Basu, Ghaly, Pegg/Dal, Dr. A. Ghaly/Dal, T. Bouman/CBU, NSCC, H. Manuel/CONA, A. Dutta/NS Agricultural College
Biofuels	Biofuels from fish oils, microalgae, agricultural waste & products, bioprocessing and biorefining, ultraclean diesel, dehydration of ethanol, small scale biogas systems, conversion using supercritical water	NB-DOE or NS-DOE	NSP/NBP	Ocean Nutrition, Pratt/Whitney, Honeywell, Atlantec BioEnergy, BioVision Technology	K. Shiell/NBCC, Y Zheng/UNB, C. Watts/Dal, Galley/NSCC, K. Hawboldt/MUN, R. Helleur, Dr. M Pegg/Dal, H Manuel/Marine Institute
PPAs, IPPS, Community, CEDIFS, FITs, Large Industry involvement	Analyse the pros and cons of stakeholder involvement outside of provincial utilities, successes/failures, lessons learned	NS-DOE	NSP, Maritime Electric	Fundy Tidal, Seaforth, Wind Prospect Inc., other CEDIFS, wind owner/operators	Dalhousie, UPEI, Y. Gagnon/UM

SECTION 6 FUNDING PROGRAMS AND ADDED GOVERNMENT SUPPORT

In recent years most clean energy initiatives in Atlantic Canada, ranging from pure and applied research to demonstration, have been assisted through funding and support provided by the following programs and organizations.

6.1 Financial Programs that Support Clean Energy

Natural Sciences and Engineering Research Council (NSERC)

NSERC provides assistance through investments in innovative research to "increase Canada's scientific and technological capacities for the benefit of all Canadians." NSERC provides supporting funding for postsecondary students and professors, postdoctoral researchers, and Canadian companies for RD&D in their specific area of advanced study and/or industry. In the past decade, NSERC has provided greater than $7 billion in RD&D funding for projects at postsecondary institutions and industry, and/or their partnerships. Additionally, with NSERC funding, training programs have been developed and implemented to assist postsecondary students with careers advancements in science and engineering. "NSERC reports to Parliament through the Minister of Industry…" and is presided over by Dr. Suzanne Fortier, President, and a Council, consisting of 18 appointed members. (Source: http://www.nserc-crsng.gc.ca/NSERC-CRSNG/vision-vision_eng.asp).

NRC Industrial Research Assistance Program (NRC-IRAP)

NRC-IRAP is a national "…innovation assistance program for small and medium-sized enterprises (SMEs)…" and is one of the important aspects of NRC innovation systems. (Source: http://www.nrc-cnrc.gc.ca/eng/ibp/irap/about/index.html). NRC-IRAP has been in service for 60 years with regional offices across Canada. The NRC-IRAP mandate is to "…stimulate wealth creation for Canada through technological innovation…" through SMEs. Their strategic objectives are geared to "…provide support to (SMEs) in Canada in the development and commercialization of technologies; (and to) collaborate in initiatives within regional and national organizations that support… (SMEs).
(Source: http://www.nrc-cnrc.gc.ca/eng/ibp/irap/about/mandate.html).

Natural Resources Canada Program of Energy Research and Development (NRCan PERD)

PERD operates on a federal level within NRCan and is an interdepartmental program; participating agencies and/or departments include: Agriculture and Agri-Food Canada; AECL; CMHC; EC; DFO; HC; INAC; Industry Canada; DND; NRC; NRCan; PWGSC; and TC. NRCan

PERD provides funding support in R&D "…designed to ensure a sustainable energy future for Canada in the best interests of both our economy and our environment." Departments and/or agencies may collaborate with a variety of sources including "…private sector…; other funding agencies; universities; provincial and municipal governments and research organizations; and international organizations." (Source: http://www.nrcan.gc.ca/energy/science/programs-funding/1603)

Atlantic Innovation Fund (AIF)

The AIF is an initiative provided by the Government of Canada, which has been specifically geared towards "…helping Atlantic Canadian research facilities complete in a global knowledge-based economy…" through access to funding for RD&D projects involving innovative "…ideas, technologies, products and markets." The AIF provides access to funding under the Atlantic Canada Opportunities Agency (ACOA) for "selected eligible projects through a series of competitive funding rounds." In the past decade, AIF has provided approximately $709 million in funding to a total of 279 selected projects with additional funding support ($61 million) secured in March 2011 for another 26 Atlantic Canadian projects. (Sources: http://www.acoa-apeca.gc.ca/eng/ImLookingFor/ProgramInformation/AtlanticInnovationFund/Pages/AtlanticInnovationFund.aspx).

Clean Energy Fund (CEF)

The CEF was initiated under the Government of Canada's *Economic Action Plan* to assist with Canada's commitment to a 17% reduction of 2005 of greenhouse gas (GHG) emission levels before 2020. The CEF objective is to take "…action to ensure a healthy environment." Funding provided by the CEF invests in "…large-scale carbon capture and storage demonstration projects and smaller-scale demonstration projects of renewable and alternative energy technologies." Approximately $146 million has been allocated for investing in support of "renewable, clean energy and smart grid demonstrations…" throughout Canada.
(Source: http://www.nrcan.gc.ca/energy/science/programs-funding/1482)

Sustainable Development Technology Canada (SDTC)

SDTC "is a not-for-profit foundation…" established by the Government of Canada in 2001 administered by the Minister of Natural Resources Canada. SDTC provides supporting funding towards "…development and demonstration of clean technologies…" Two funds are operated under SDTC for funding innovative ideas and solutions "…which deliver economic, environmental and health benefits to Canadians"; these funds are the SD Tech Fund™ and the NextGen Biofuels Fund™. The two funds provide access to $590 million and $500 million in supporting funding, respectively, for climate change, air quality, clean water and soil, and "…establishment of first-of-kind large demonstration-scale facilities for the production of next-generation renewable fuels."
(Source: http://www.sdtc.ca/index.php?page=sdtc-profile&hl=en_CA)

MITACS

Mitacs is a national, not-for-profit research organization that provides funding for training and research for innovative next-generation researchers and facilities. Mitacs partners with various federal and/or provincial government departments and agencies (i.e., Government of Canada

under the *Economic Action Plan* and Networks of Centres of Excellence, the provincial Governments of BC, AB, SK, MB, ON, QC, NB, NL, and NS), research facilities, and academic institutions to provide support towards fostering a new innovative economy in Canada. Mitacs provides funding under 6 individual projects: Mitacs – Accelerate (research internship program); Elevate ("…a foundation (for) research, business, entrepreneurship and scientific management skills to newly-minted PhDs); Globalink ("…introduces Canada as a world-leading research and innovation destination to top undergraduate students from around the world"); Entreprise ("a competitive 6-month internship and business mentoring program…"); Step (provides "…business-ready skills to up and coming researchers."); and Outreach (provides assistance to reach out to "future researchers – our children – through innovative initiatives…"). (Source: http://www.mitacs.ca/about).

Canada Foundation for Innovation (CFI)

CFI is an independent, NGO represented by an active Board of Directors that was established in 1997 by the Government of Canada "…to build Canada's capacity to undertake world-class research and technology development to benefit Canadians" (Source: http://www.innovation.ca/en/AboutUs/History). CFI funds various forms of infrastructure (i.e., "state-of-the-art equipment, laboratories, databases…scientific collections, computer hardware and software, communication…and buildings) "…necessary to conduct leading-edge research" at Canadian institutions not individuals (http://www.innovation.ca/en/AboutUs/WhatCFI). CFI support if categorized into specialized funds: Leading Edge and New Initiatives; Leaders Opportunity Fund; College-Industry Innovation Fund and other industry-specific funds.

Newfoundland and Labrador Green Fund

The NL Green Fund was established by the Government of Canada *EcoAction Trust Fund for Clean Air and Climate Change* and was provided with funding for a "…three-year period to support projects that provide real reductions in (GHG) emissions." The NL Provincial Government included additional funding for the NL Green Fund and "…expanded the criteria to include aspects of environmental sustainability." The NL Green Fund was "no longer accepting application for this fund as of June 29th, 2009."
(Source: http://www.env.gov.nl.ca/env/climate_change/govt_action/greenfund.html).

Research & Development Corporation of Newfoundland and Labrador (RDC)

The RDC is a provincially-based entity that provides funding to RD&D projects in Newfoundland and Labrador (NL) that "…will play a major role in driving innovation, creating wealth and increasing economic growth…for future generations." The RDC was "incorporated under the *Research and Development Council Act* in 2009…" and operates indirectly with the NL

Government. RDC plans to focus their efforts in the next decade on the following objectives: "…Increasing overall R&D investment in Newfoundland and Labrador; pursuing R&D opportunities that are relevant to the local economy; targeting sectors that are of strategic

importance to (NL's) economy; understanding current and future market and research needs; responding quickly and flexibly to opportunities; and encouraging key stakeholders to collaborate and cooperate in the R&D process."
(Source: http://www.researchnl.com/about/index.htm)

Innovation Prince Edward Island (Innovation PEI)

Is a provincially-based entity that provides focus "…on advancing economic development…by investing in people, innovation, and infrastructure." Innovation PEI is based on the *Island Prosperity Strategy* whereby "…targeting key sectors (i.e., bioscience, IT, renewable energy and aerospace) that have displayed a high potential for economic growth within the Province" (Source: http://www.innovationpei.com/index.php3?number=1029613). Innovation PEI provides support by offering a wide variety of programs and services including research chairs, development funds, publications, business improvement programs, etc.

Nova Scotia Research and Innovation Trust (NSRIT)

NSRIT is a provincially-based trust that "…supports research infrastructure in (NS) by matching national funding from (CFI)." To date 340 projects at research facilities in Nova Scotia have been provided a portion of a total $66 million in funding. This funding supports researchers in "...Health and Life Sciences, Ocean Technology, Clean Technology, and Information and Communications Technology." (Source" http://nsrit.ca/)

Nova Scotia CleanTech Open

Is a private clean technology start up competition presented by Innovacorp (a venture capitalist company in Nova Scotia), that is "…designed to find and fund high potential clean technology start ups." The competition started in Dec 2011 with pitch presentations conducted between Feb 13 and 17, 2012, with competition winner announced in April 2012. (Source: http://www.novascotiacleantech.com/about)

NB Climate Change Action Fund

Through the Climate Change Action Fund (CCAF), New Brunswick recently supported six innovative projects in energy. The projects ranged in scope from designing more energy efficient homes, to small hydro re-development, biomass combined heat and power, smart-grid applications and the largest anaerobic digester in Atlantic Canada. All CCAF projects will result in significant reductions of greenhouse-gas emissions and air pollution throughout the province. (*Source: NBDOE*)

New Brunswick Innovation Foundation (NBIF)

NBIF is a provincially-based venture and research capital company that provides funding to start-up projects and R&D. Investments into company's equity are made rather than providing a loan or lender agreement. NBIF designates 5 key strategic industries: "Energy & Environmental Technologies; Knowledge & ICT; Life Sciences; Value-added Natural Resources; and Advanced Manufacturing." Additionally, NBIF offers investment support to education and training efforts (Research Assistantship Initiative only). (Source: http://www.nbif.ca/eng/about/)

New Brunswick Environmental Trust Fund

NB's Environmental Trust Fund uses revenues from the provincial container recycling program to support innovative projects, including energy projects that result in tangible, measurable results, and are aimed at protecting, preserving and enhancing the Province's natural environment. (*Source: NBDOE*)

Canadian Innovation Commercialization Program (CICP)

CICP was announced in Budget 2010 to help companies bridge the pre-commercialization gap for their innovative goods and services by awarding contracts to entrepreneurs with pre-commercial innovations through an open, transparent, competitive and fair procurement process; providing feedback to the entrepreneurs on their products; providing opportunities to enter the marketplace with a successful demonstration of their product ; and, providing information on how to do business with the Government of Canada. The CICP is aimed at several business sectors, including alternative energy (wind, solar, water (low-head, tidal, wave, etc.), geothermal, biofuels, biomass, hydrogen, component technologies (e.g. inverters, generators, control systems)) and energy efficiency (including grid integration technologies, innovative energy storage, heat exchangers/pumps).

The program includes a series of RFPs that include a description of the priority business sectors and criteria for selection. Regional events and trade shows are held so Canadian businesses can showcase their innovative concepts to federal representatives. CICP is managed by Public Works and Government Services Canada and implemented by the Office of Small and Medium Enterprises, which advocates on behalf of small and medium enterprises in federal procurement.

ecoEnergy Innovation Initiative (ecoEII)

EcoEII received funding in Budget 2011 for a large array of research, development and demonstration projects, including clean electricity and renewable and bioenergy. The main purpose of the program is to support innovation to produce and use energy in a cleaner and more efficient way. Two separate funding streams are available; one focused on R&D projects and the other on demonstration projects. Both were launched with requests for Letters of Expression of Interest and closed in fall 2011. NRCan states on their website that "there is no current call for proposals and at present we do not expect that there will be any further calls".

Community Economic Development Investment Funds (CEDIFS) and Community Feed-in Tariffs (ComFITs)

In Atlantic Canada, only Nova Scotia has a renewable energy Feed-In Tariff program, and only Nova Scotia and Prince Edward Island have CEDIF programs (called the Community Economic Development Business program in PEI). While neither of these programs are meant to incent clean or renewable energy RD&D, both can be used to support such initiatives. A CEDIF's activities can include RD&D activities (depending o the desires of the shareholders and directors).

Nova Scotia's ComFIT program (and FITs typically) are intended to allow a broad deployment of commercial technologies by individuals and organizations in a way that is economically viable. The FIT guaranteed rates and contract terms allow proponents to obtain financing and ensure a reasonable rate of return on their investment. It is possible that the leveraging potential of a FIT rate could allow a renewable energy proponent to conduct RD&D activities that are complimentary to their business.

6.2 GOVERNMENT SUPPORT - FACILITATING THE ADVANCEMENT OF CLEAN ENERGY INITIATIVES IN ATLANTIC CANADA?

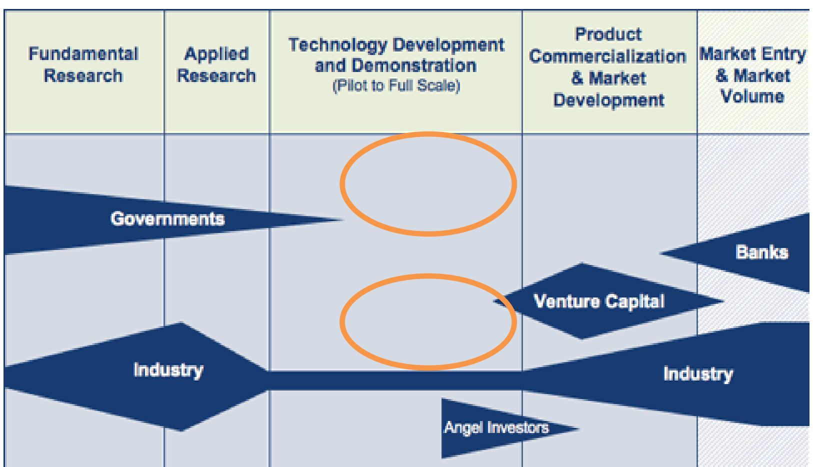


Figure 7 – Development Funding "Pinch"

The discussion above within this section of the report illustrates the broad range of funding programs available from the federal government and provincial governments. Outside of the Clean Energy Fund and its support for three of the four key clean energy projects discussed, many funding programs target the early stages of fundamental and applied R&D and innovation. With reference to Figure 7, it is evident that funding support is "pinched" mid-stream in the development and demonstration phase until product commercialization and market entry, when industry, banks and venture capitalists become involved.

The AEG is focussed specifically on the "Atlantic electricity sector" with the goal of facilitating the development of clean and renewable energy to displace GHG-emitting sources of electricity. Earlier sections of this report allude to the fact that technology development and demonstration projects appear to be of most interest to industry and utilities in Atlantic Canada's electricity sector. The point has been made that the four primary RD&D project examples are within the development and demonstration stage, in the middle of the innovation chain noted. To restate, this is not to say that pure fundamental research should not be supported, and examples of such programs have been provided herein. An overall policy consideration for the AEG is, therefore, to work with industry to continue to assist in funding projects in the middle innovation chain RD&D stage.

An underlying key message in this report is the value in partnering and participation within industry, in collaboration with researchers. These values are consistent with four key pillars of the AEG mandate: **COLLABORATION, COOPERATION**, and **COMMON UNDERSTANDING** toward **DEVELOPMENT** of the renewable energy sector in the region. The components of highly rated and effective R&D projects are noted in Section 4, and, good projects are those that embrace these underlying principles.

The analysis so far in this report is meant to provide intuitive areas of consideration for the AEG and members of the AEG Steering Committee. Ultimately technical analysis preferably by experts within the electrical sector, is required to determine projects of interest with respect to the advancement of clean energy as it pertains to electricity generation.

SECTION 7 CONCLUSION AND POLICY CONSIDERATIONS

All four Atlantic Provinces have different energy resources and electrical energy generation mixes. All are making efforts to move toward a more diverse energy portfolio by harnessing sources that produce less greenhouse gases. Over the next two decades, provinces have an opportunity to capitalize on the strengths and diversities of each other to advance clean energy locally and across the entire region.

Atlantic Canada has natural resources that can yield significant, new and expanded clean energy sources, including tidal energy, hydroelectric power, wave energy, biomass sources and related biofuels, and wind power. The contributions that our scientific and technical communities are making to the development of clean energy are helping to advance clean energy initiatives around the world.

It is clear that clean energy capacity clusters exist where one particular institution has built a significant capability in a specific area of interest. Examples would include Acadia’s strength in environmental studies related to tidal, and UNB’s unique Sustainable Power Research Group. Memorial has highly qualified people engaged in individual clean energy projects. In other clean energy areas, such as battery/fuel cell R&D, capabilities exist throughout the region.

Academics working with industry is a given. There is but an added need for researchers to work more cooperatively with each other within and across institutions on a local and regional basis, so a second key consideration is the importance of academic cooperation.

NL priority areas, also of regional interest and potential cooperation, lies in: onshore wind; large and small hydro; the effects of cold/snow/ice on wind turbine performance; small wind technologies; storage and integration technologies, and (while not in all cases RD&D); forest based biomass and wood pellets. Areas of clean energy R&D in NL is focussed on aspects of: wind energy (wind/hybrid systems, advanced weather forecasting for wind, even a craft to access offshore wind farms); some wave energy, biofuels from fish oil and forest residue; and fuel cells. Work by Nalcor/NL Hydro continues in hybrid systems, wind and wind environments, small hydro and hydro related climate / environmental studies.

NB is focussed on smart grid technologies and other issues related to demand side management; wind balancing and integration; smaller scale renewable energy developments – biofuels, small hydro, wind; community, First Nations, and large industry involvement, and; biomass and wood pellets. In terms of academic capacity in NB, much work is concentrated in the areas of enabling technologies and demand side management (DSM), hydrogen storage and fuel cells. Through PowerShift, NB is leading the region in DSM efforts. There is additional capacity in biomass/biofuels and ongoing work related to wind, particularly at the University of Moncton. UNB's unique capacity under the Sustainable Power Research Group is of benefit to the region as a whole.

Nova Scotia has the largest accessible tidal resource in Atlantic Canada, and is clearly focused on this source as having great future potential. The use of various forms of biomass to generate heat (and electricity) is also of great interest in NS. Extensive RD&D work is currently underway in Nova Scotia, both for large and small-scale tidal conversion. NS R&D capacity in biomass energy and biofuels is significant, and other provinces should look to partnerships with the NS academic community. As well, Dalhousie leads efforts in advanced related enabling technologies (fuel cells).

In PEI, government priorities lie in all areas (large and small) of the wind sector, as well as in bioenergy (biomass and biofuels). Some interest may exist in tidal lagoon potential in the Northumberland Strait, and it was noted that PEI was once a per capita leader in solar thermal residential use. PEI's development of the Wind Energy R&D Park and Storage System for Innovation in Grid Integration (Park) will benefit the region as it strives to address the various challenges of wind energy.

While each province has unique energy mixes, and levels of academic capacity that are as well provincially unique, the analysis reveals that broad regional interest on the part of all four provinces exists in: harsh environment impacts and forecasting; small wind applications; biomass; and energy storage. These interests and regional priorities generally match academic capacity, private sector involvement and ongoing related studies in the region as a whole. In terms of regional spread, most funding for clean energy is focussed on wind, enabling technologies often related to wind, and biomass/biofuels. The review of R&D capacity reveals that regional strengths exist in the areas of enabling technologies (NS, NB, and NL), biomass

(NS, NB), wind (PEI, NB, NS, NL) and biofuels (NB, NS). Localized capacity exists in tidal (NS), wave (NL) and some solar (NS).

Matching these broad regional priorities with regional academic capacity leads to conclusions and policy considerations that are consistent with these findings:

- Projects as noted in Table 3 exhibit considerable potential for regional partnering between governments, the private sector, and academia in the areas identified.

- The parameters that define an effective R&D project should be considered: local relevance; chance of use-ability and innovation; established priorities shared by government and industry; industry engagement and willingness to leverage financing; market need; global linkages when beneficial.

- Work with industry to continue to assist in funding projects in the middle innovation chain RD&D stage.

    - Decision makers might consider a rating scheme for projects in which a progressively increasing percentage of government contribution is triggered when key criteria/requirements are met in keeping with the overall mandate of maximizing regional cooperation and common understanding. Rated criteria / parameters as noted include: local relevance; chance of use-ability and innovation; established priorities shared by government and industry; industry engagement and willingness to leverage financing; market need; and global linkages when beneficial.

    - Additional favourable project attributes include the level or regional cooperation between provinces and academia, as well as the level of cooperation between individual researchers / High Quality People (HQP) working together within and across regional institutions.

- If international expertise is deemed to be necessary or advantageous in enhancing a project, then fund day-rates/allowances, travel, accommodations to bring them to the table.

- In terms of international potential or export, recognize that the export of electricity is one aspect, but equally important is the export of technology or solutions with international reach, such as off grid applications.

CLOSING

This report has been prepared by SLR Consulting (Canada) Ltd. with all reasonable skill, care and diligence, and taking account of the resources devoted to it by agreement with the client. Information reported herein is based on the interpretation of data collected and has been accepted in good faith as being accurate and valid.

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Individuals contacted during the course of this study:

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www.nsrenewables.ca for ComFIT and CEDIF information links

Atlantic Energy Gateway (AEG) Balancing Study Report

A Study of Potential Savings in the Case of a Common Unit Commitment and Dispatch Function for Atlantic Canada

FINAL REPORT
June 15, 2012

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Atlantic Energy Gateway (AEG) Balancing Study Report

A Report on Potential Savings in the Case of a Common Unit Commitment and Dispatch Function for Atlantic Canada

Executive Summary

The Atlantic Energy Gateway (AEG) project is a regional initiative of the federal government, the Atlantic provincial governments, electric utilities of Atlantic Canada and the system operators in New Brunswick and Nova Scotia. The objective of the AEG project is to contribute to the development of Atlantic Canada's clean energy resources by identifying the opportunities and assisting in evaluating the advantages of the region's substantial and diversified renewable energy potential for wind, tidal, solar, biomass/biofuels, geothermal and hydro.

The New Brunswick System Operator (NBSO) has studied the potential savings of a common unit commitment and dispatch function for balancing electricity supply and demand in Atlantic Canada. This work was undertaken at the request of the AEG Steering Committee and performed with direction from the AEG System Operations Technical Committee and an AEG Balancing Study subgroup. Funding for third-party expenses was provided by the government of Canada in accordance with a contribution agreement.

The fundamental hypothesis behind the study is that savings can be achieved by balancing electric power system resource demand and supply in Atlantic Canada on a common basis rather than separately as is done today. Currently New Brunswick, Northern Maine and Prince Edward Island are balanced as one balancing area. Nova Scotia and Newfoundland are each balanced on their own as indicated in Figure 1.

Fig. 1 Separate Balancing

NBSO has no knowledge of a contemporary study of this nature having been undertaken by others. It is, however, a commonly accepted belief that balancing supply and demand would be less expensive under a regional dispatch. Diversity of both supply and demand is one driver of savings. The ability to select supply from a broader portfolio of resources is another driver.

The introduction of intermittent renewable supplies (e.g. wind power, in-stream tidal, and solar) to the power system accentuates the benefits of a common regional dispatch because of the corresponding increase in the need for balancing. A common regional dispatch can also ease the integration of more conventional but inflexible generation such as nuclear and some co-generation.

Figure 2 explains the sources of expected savings from using a single unit commitment and dispatch function to balance the regional power system in Atlantic Canada.

Fig. 2: Nature of Expected Cost Savings with Regional Balancing

Cost =	**Quantity x Price**
Quantity	Lower balancing needs due to: - diverse consumption (lifestyle, time, season, weather, etc.) - diverse inflexible generation (nuclear, wind, tidal, cogeneration, etc.) - diverse timing of loss of supply
Price	Less expensive to perform balancing due to: - size selection (start a small generator rather than a large generator) - flexibility (fast hydro vs. slow thermal units) - timing of generation outages and derates - timing of hydro conditions (run-off, dry spell, etc.) - removal of transmission tariff charges within region

This project created a model, database, and skill-set that could be used for future study work including:

- an update of this balancing study with forecast errors included;
- analyzing the impact of various quantities and types of renewable generation;
- assessing the value of various dispatchable generation, load control, and storage options;
- identifying the savings of other collaborative balancing options; and
- quantifying the impact of various provincial and regional emissions policy options.

The opportunity to use this model and database for future regional studies is dependent on utility agreement to allow the confidential portions to persist and be used appropriately.

It is important to note that the results are specific to the timeframes indicated. Additionally, the results are a function of the assumptions that were made regarding consumption characteristics, supply availability, and the characteristics of the supply. The study was performed for two test years. The 2010/11 test year was studied in order to validate the simulation model using actual historical data, and to quantify the potential savings of a common Maritime Provinces dispatch for the current power system. The 2020 year was studied in order to quantify the potential savings of a common Atlantic Canada dispatch for a single year in which the system would include the Muskrat Falls hydro generation development and interprovincial transmission projects. The supply resources for that test year would also include generation builds and retirements identified in the AEG Resource Development Technical Committee's least cost combined integrated resource planning scenario.

The key results of the balancing study are summarized in Table 1. The table shows savings in two timeframes. The savings in the 2010/11 year estimate what could have been achieved had the balancing for the Maritime Provinces and northern Maine been performed collaboratively rather than having each of the New Brunswick/PEI/northern Maine system and the Nova Scotia system balanced on its own. The simulation of the 2020 year estimates the savings of balancing the Atlantic Provinces and Northern Maine as one area rather than as three, given the anticipated expansion of the region's intermittent renewable energy resources by 2020. Further details and explanations of the cases are contained within this report. All dollar figures in this report are in 2015 Canadian dollars unless otherwise indicated and were converted from then-current dollars based on 2% annual inflation.

Unit Commitment and Dispatch Savings

The study indicates a one-year savings in unit commitment and dispatch costs from combining balancing areas of approximately $25.1 million in the 2010/11 test year. For the 2020 test year the savings indicated by the study are $7.9 million.

Ancillary Services Capacity Savings

Regulation and Load Following are services that are ancillary to electric demand and energy commodities and are used to perform the balancing function. Regulation service involves adjusting the output of generators within seconds to match short term fluctuations in generation requirements. Load Following service involves adjusting the output of generators over minutes up to an hour to match increasing or decreasing generator requirements.

Given the reduced requirements for capacity for regulation and load following the savings in the incremental capacity cost associated with these services (based on an assumed cost of $10/MW-h for Regulation, $8/MW-h for Load Following, and $7/MWh for 10-minute spinning reserve) is $0.4 million in 2010/11 and $0.7 million in 2020.

Table 1 Results Summary ($m in 2015 dollars)

	2010/11			2020		
	2010/11 Three Areas	**2010/11 Two Areas**	**Impact of Sharing (i.e. Savings)**	**2020 Three Areas**	**2020 One Area**	**Impact of Sharing (i.e. Savings)**
Transmission	Current	Current	_	Upgraded	Upgraded	_
Supply mix	Current	Current	_	Combined Plan	Combined Plan	_
Generation costs	$840.8	$815.7	$25.1	$706.9	$644.8	$62.1
Cost of imports	_	_	_	$6.3	$5.2	$1.1
Revenue from exports	_	_	_	$196.8	$141.5	$55.3
Ancillary services costs	$1.7	$1.3	$0.4	$2.4	$1.7	$0.7
Total	$842.5	$817	$25.5	$518.8	$510.2	$8.6

Due to changes in the inputs, such as fuel costs, that occur over time, it is not valid to simply extrapolate these results out to multiple years. However, these results do provide an indication of the order of magnitude of the potential savings.

The model that has been built and validated can be used to study additional system configurations and time periods. That work would require the assembly of the appropriate additional data, and permission from utilities to re-use the confidential data that was used in this study. This study has also set a precedent for regional collaboration that could be extended beyond study work to greater collaboration in actual system operations.

This balancing study addresses some of the limitations of the study work that was performed in the AEG resource development study with respect to variability of energy needs, generator characteristics, and ancillary services. Like all production cost studies, this balancing study complements, but is not a replacement for more technical reliability studies.

The production cost savings assessed in this study are not entirely incremental to those in the resource development study. They are another view of the same type of costs, but with a more accurate reflection of how the power system operates. The tradeoff for the operational accuracy is that it was only feasible to study relatively short periods of time (one year in each case) within the scope of the project. Building and using a model to simulate multiple years of operation would take longer and be more costly. This balancing study does isolate the reduction in production costs achievable by operating with combined balancing areas rather than separate ones given the assumed transmission and generation plan. To follow that transmission and generation plan without implementing regional dispatch would mean that the region would forego these potential savings.

The purpose of this study is to provide indicative quantification of the potential savings. The results are intended to inform policy makers and help them evaluate the appropriateness of pursuing a common system balancing function. These estimates of savings do not take into account the costs of implementing the common dispatch or the administrative savings of performing this activity on a regional basis. Furthermore, this study does not consider the potential costs or economies of scale associated with performing other system operations functions on a regional basis. The impact of performing any system operator function, such as balancing, on a regional basis must account for impacts on various stakeholders including the allocation of the savings.

The savings identified in this report should be considered in conjunction with other AEG work product including those related to how a common regional dispatch might be achieved. That being said, it is important to note that there are various models that have been suggested as a means to implement a common regional dispatch. These include a regional system operator, contracting of services to one system operator, coordination agreements between utilities, and a regional system administrator.

The initial objectives of this study have largely been achieved. A model has been built that addresses some of the limitations of other production cost models in how the power system is balanced operationally. The potential savings of a common unit commitment and dispatch function for balancing electricity supply and demand in Atlantic Canada for the years 2010 and 2020 have been estimated as planned. A robust and detailed set of wind power and consumption data has been created. A set of simulated forecasts for both of these data sets has also been created. The region has increased its knowledge and skill set with respect to modelling the regional power system.

The study results and the non-confidential data are available for other analysis and study work related to regional system operations. While the original objective of being able to sustain the model and portions of the associated database has not been achieved, future study work in the region can benefit from the non-confidential data, knowledge, and skill set produced by this exercise.

Background

A resource development optimization study was undertaken as one of the key components of the AEG project. During the course of defining that study, that project's workgroup expressed concern that the exercise would not accurately represent 5-minute variability of consumption and wind power production, generator characteristics, and operating reserve requirements.

Subsequently, the AEG System Operations Technical Committee asked NBSO for a study to be scoped out for an update to the NBSO's 2007 Maritimes Area Wind Integration Study based on its work on that study and the NBSO's procurement of more advanced modeling capability. A scoping document for a "balancing study" was submitted to that committee on May 5, 2011 for consideration and comments. The scoping document and the need for such a study were discussed by that committee during a conference call on May 16, 2011. The comments were generally favourable. That earlier scoping document suggested an analysis of a variety of scenarios including one considering the sensitivity of greater development of wind power and one for load control. The tentative schedule called for the work to be completed by March 1, 2012.

On May 24 & 25 the AEG Steering Committee also discussed the need for a study of this nature. It was noted that the AEG work was to be completed by the end of 2011, but that there was an interest in having a study of that nature performed. NBSO suggested a reduced scope that would focus on the benefits of collaboration including with respect to balancing and operating reserves. The AEG Steering Committee then asked NBSO to submit a proposal by June 9, 2011 to undertake a balancing study of a reduced scope that would be completed by the end of 2011. Accordingly, NBSO proposed a balancing study for consideration by the AEG Steering Committee. That proposal was reviewed and accepted by the AEG Steering Committee at a meeting on June 9, 2011.

The key deliverable is an estimate of unit commitment and dispatch savings arising from regional collaboration in balancing and operating reserves. The primary goal of the study is to provide analysis with respect to system balancing and operating reserves in Atlantic Canada in support of the overall AEG objective of supporting renewables development through regional cooperation.

The 2007 Maritimes Wind Integration Study confirmed that commercial scale integration of wind power would increase the cost of system balancing including load following. The diversity benefits of pooling the loads and wind generation of the Maritime Provinces were examined based on simulated wind power production. The 2007 study was based on integrating up to 1000 MW of wind power into the Maritime Provinces. Since then the amount of wind power being considered for installation has increased to in excess of 2000 MW. At this level the incremental requirements for balancing including load following are still expected to be material compared to the quantities needed to manage variations in load.

In the Maritimes Wind Integration Study various suggestions were made as to how the Maritime Provinces could adapt to the introduction of wind power as indicated in the following extraction from that report.

> *The project work has identified a number of areas in which the cost of integration might be reduced. The following are suggested to somewhat mitigate these issues:*
>
> - *improved production forecasting methods to be developed by both the market participants for wind facilities, and system operators,*
> - *development within each balancing area to be spread around geographically so as to take advantage of the diverse wind speeds,*
>
> *In addition there are a number of things that should be explored to try and ease the accommodation of the variability and uncertainty such as the following:*
>
> *(1) Pursue less onerous deadlines for schedule changes by Market Participants with ISO-New England,*

(2) NBSO pursue use of 15 minute schedules with ISO-New England and Quebec,
(3) Explore the possibility of dynamic scheduling with ISO-New England and Quebec,
(4) Demand response capability be developed including bid-based demand response,
(5) Market rules and connection agreements must provide the right for production from generation facilities, including wind, to be curtailed as necessary to maintain system reliability,
(6) Market participants in the NB/PEI/NMe Balancing Area selling or buying output from wind facilities should structure contracts so that they can balance schedules hourly (or perhaps even every 15 minutes in the case of transactions with other Areas) to accommodate fluctuations in forecasted production,
(7) A regional joint RFP for capacity based ancillary services be implemented to encourage use of more resources for the provision of these services,
(8) Nova Scotia and the NB/PEI/NMe Balancing Area could form a Maritimes Balancing Area so as to take greater advantage of diversity of wind speeds, system peaks, and generation capabilities (one approach that should be considered is to implement a joint dispatch of regulation and load following as a precursor to forming some form of regional market).
(9) Policies should accommodate storage facilities (pumped hydro, compressed air, etc.).

One of the benefits of a regional approach to balancing is that it would take advantage of the significant diversity that exists across the region in wind regimes. The 2007 study examined a hypothetical 1000 MW of wind power in the Maritimes Provinces. The standard deviation (a measure of variability) for hourly swings in wind power dropped from 69.6 MW (i.e. 38.5 + 31.1) under the current arrangement of two balancing areas to 51.5 MW for a single Maritime Provinces balancing area.

Wind and Load Variability
(Data from Table 4 of 2007 Maritimes Wind Integration Study)

	One Balancing Area			Separate Balancing Areas					
	Maritimes (1000 MW of Wind)			NB/PEI/NME (600 MW Wind)			NS (400 MW Wind)		
Standard Deviation (MW)	Load	Wind	Net	Load	Wind	Net	Load	Wind	Net
	127	51.5	137	83.7	38.5	92.2	60.1	31.1	67.8

There is now more historical wind power production data available and more sophisticated means to simulate future production - thereby providing an opportunity to update the analysis of 2007. Rather than examining the standard deviation of wind power the balancing study analyses the impact of combining balancing areas on the overall load following requirements. The AEG project has, however, created data sets of wind power production that could be used to examine standard deviation for swings in wind power production in various resolutions as fine as 5 minutes.

In addition to the specific studies requested, the AEG Steering Committee also wanted a regional model that could be used for future studies. The project was therefore proposed and started on the understanding that the inputs could be agreed upon by the project's participants, would not be confidential, and would produce a regional model for future use.

During the course of the project some of the utilities requested that the study use confidential data for some of the utility-specific inputs. Therefore additional lead time was required to establish non-disclosure agreements. In addition, the setting up and refining of the model required more time than what was originally expected. The additional time that was required is somewhat attributable to the complexities of the system that was modelled. Furthermore, the use of confidential data means that at the end of the project the confidential data is to be removed from the model. Therefore the enduring regional model will be incomplete and would need to be repopulated for any future regional study work.

Study Approach

The study examines the unit commitment and system dispatch costs for two scenarios. The first scenario assumes that the obligations for intra-hour balancing and operating reserves rest with the respective Balancing Area and that there are three Balancing Areas (Nova Scotia, Newfoundland, and the current New Brunswick Balancing Area which is comprised of New Brunswick, Prince Edward Island, and Northern Maine). The second scenario assumes that there is a single Balancing Area in Atlantic Canada and Northern Maine with a common obligation for intra-hour balancing and operating reserves.

Due to the data preparation and computer processing time that would be required, the scenarios were modelled for individual test years, not a multi-year period. Also, the results are dependent upon a number of input assumptions. For example, emission constraints were modelled to reflect various requirements, but those requirements may very well change over time. Therefore the results are indicative of the potential unit commitment and dispatch savings in a given year. These numbers cannot be considered as typical or representing an average for an extended number of years.

The removal of incremental transmission charges in the study for flows between provinces contributes to the efficiency of the single balancing area. The following table indicates other sources of potential savings of a single balancing area, whether or not those savings are realized today, and whether or not they were modelled in the balancing study.

Source of Benefits	**Done Today?**	**In AEG Study?**
Efficient day-ahead unit commitment	Very Limited	Yes
Efficient procurement of ancillary services	Limited	Yes
Efficient intra-day unit commitment (e.g. use of combustion turbines)	Limited	Yes
Efficient intra-hour dispatch of energy	No	Yes
“Pooling” of load following requirements	No	Yes
“Pooling” of regulation requirements	No	Yes
“Pooling” of forecast error	No	Future Study

Difficulties were encountered with the Hour-Ahead simulations at 5-minute resolution which were intended to more closely simulate actual system dispatch that occurs within the day. The lengthy solution times, large data set, and significant number of modelling options proved challenging. As a consequence, reasonable results for the Hour-Ahead simulations were not produced in time for inclusion in this report.

Scenarios to be Studied Under AEG

The following scenarios were studied to provide information that policy-makers can use when considering policy options related to regional collaboration in operations including in support of renewables integration.

2010/11 Base Case

The purpose of this case is to assess the validity of the model by comparing it against the actual unit commitment and dispatch that occurred in 2010/11.

The characteristics of this case include:
- Existing generation including wind farms
- Current balancing areas (NS, NB/PEI/NME and NL)
- Actual load with actual or simulated 5-minute resolution
- No load control
- Daily hydro energy limits per facility
- Existing transmission and inter-area transfer capabilities
- Hourly zonal economic optimization of unit commitment and dispatch for each Balancing Area
- Balancing via Automatic Generation Control (AGC) intra-hour
- Hourly schedules on transfers between Balancing Areas
- Reserve sharing as per the existing arrangement between NB and NS
- Assume perfect wind power production forecasts for simplicity
- Assume perfect load forecasts for simplicity

2010/11 Two Balancing Areas

The purpose of this case is to assess the unit commitment and dispatch savings that could have resulted from operating the Maritimes as a single Balancing Area. Operating Atlantic Canada as a single Balancing Area in 2010/11 was not studied because without an electrical connection such as the Maritime Link, that scenario was not feasible.

The characteristics of this case include:
- Variation to 2010/11 Base Case
- Merging from 3 to 2 balancing areas (NS/NB/PEI/NME and NL)

2020 Base Case

The purpose of this case is to assess the operation of the system that is identified by the resource development analysis to be least cost. This case can then be used as the comparison for other cases that are purposefully selected to quantify the consequences (including the costs and benefits) of various policy decisions.

The characteristics of this case include:

- Expected generation including wind farms
- Size of uncommitted wind farms at 100 MW each, with location to be set by NBSO with assistance of local utility
- Current Balancing Areas (Nova Scotia, Newfoundland, and the current New Brunswick Balancing Area which is comprised of New Brunswick, Prince Edward Island, and Northern Maine)
- The obligations for intra-hour balancing and operating reserves rest with the respective Balancing Area and there are three Balancing Areas (but with Reserve sharing in the Maritimes as per the existing arrangement between NB and NS)
- Operating Reserves in accordance with NPCC Directory 5 (Dec 5, 2010)
- Hourly zonal economic optimization of unit commitment and dispatch for each Balancing Area
- Balancing via Automatic Generation Control (AGC) intra-hour
- Hourly schedules on transfers between Balancing Areas
- Simulated wind power production with 5-minute resolution
- Expected load with 5-minute resolution (addressing correlation between load and wind)
- Assume perfect wind power production forecasts for simplicity
- Assume perfect load forecasts for simplicity
- Daily hydro energy limits per facility
- No load control is assumed for simplicity
- Expected transmission (to be defined here but follow the lead of the Resource Development group) is the existing transmission plus the Maritime Link (500 MW from Newfoundland to Nova Scotia and 250 MW in the opposite direction), the upgraded connection between Prince Edward Island and New Brunswick (at 350 MW in both directions), and the upgraded connection between New Brunswick and Nova Scotia (at 800 MW in both directions).

2020 Single Balancing Area

The purpose of this case is to quantify the costs of operating the system that is identified by the resource development analysis to be least cost, but under the assumption that the regional system is operated as a single Balancing Area with a common centralized economic dispatch and operating reserve regime. These costs will then be compared against the costs of the 2020 Base Case which has three Balancing Areas each with its own economic dispatch and operating reserve regime.

The characteristics of this case include:

- Variation to 2020 Base Case
- Collapse into a single economic dispatch and a single balancing area for the Maritimes Area and Newfoundland and Labrador.
- Assume perfect wind power production forecasts for simplicity
- Assume perfect load forecasts for simplicity
- The obligations for intra-hour balancing and operating reserves rest with the single Balancing Area
- Operating Reserves in accordance with NPCC Directory 5

While likely of interest to the AEG, the examination of sensitivities of unit commitment and dispatch costs to other factors was not to be done within the scope of this study. Nonetheless, future study work may very well take place through other forums. The future work should consider variations on resource development, forecast errors, transmission expansion, emissions constraints, and hybrid operations models. The initial balancing study will also result in a model and a regional skill set that can be leveraged to undertake other needs in the future. Some of the data was provided by a utility subject to a non-disclosure agreement which is specific to this exercise. Therefore future studies would require additional permission for the use the confidential data, or the use of other data.

One sensitivity of particular interest for future study is the impact of assuming lower transfer capability for simultaneous flows from New Brunswick to Prince Edward Island and Nova Scotia in the 2010/11 cases than what was used in the initial analysis. Also, the inter-provincial flow values that are charted in this report can be used to determine the frequency with which the model made use of interprovincial connections in excess of a given MW threshold in each of the cases that were studied.

The analysis and information provided by the initial balancing study and the capability for future studies provide value to Canada, the utilities and provinces of Atlantic Canada, NBSO and other stakeholders. Most significantly the value arises from a quantification of possible savings of regional collaboration on intra-hour balancing and operating reserves.

The presentation of the output of the simulation must not compromise any non-disclosure agreement either through direct release of confidential information or through the release of information that can be reverse-engineered to obtain confidential information.

Simulation and Analysis Tools and Inputs

NBSO populated and ran an operational unit commitment and dispatch model in order to perform the analysis described herein on behalf of the AEG. The model accounts for intra-hour variations in balancing needs, regulation, load following and operating reserves much more realistically than can other production cost models that are used within the Atlantic Provinces.

The exercise benefitted greatly from the provision of expertise and data from the utilities. To the extent required, in lieu of utility and facility specific data, NBSO used a combination of publicly available information and engineering judgement to populate the model.

NBSO used Plexos software to perform the analysis. NBSO owns a user license for the software and owns and maintains the model and other modeling parameters. Some of the data provided by utilities is confidential, commercially sensitive, and subject to non-disclosure agreements. Plexos Solutions LLC. was contracted by NBSO to assist with setting up, populating, and using the model based on their skill set, knowledge of the software, and experience with similar exercises.

AWS Truepower was contracted by NBSO to simulate wind power production because of their past work on similar exercises in other areas and their experience in forecasting wind power production in the region. AWS produced the following datasets for use in the modeling of the 2020 year:

- Simulated wind power production at 5-minute resolution for existing and prospective sites throughout Atlantic Canada.
- Synthesized day ahead and hour ahead wind power production forecasts
- Synthesized day ahead and hour ahead consumption forecasts for each of the four Atlantic Canadian provinces

The wind power production dataset was based on 2005 as an historical test year. In order to account for weather related effects, the shape of the simulated 2020 consumption used in the modeling was based on the load shape of that same test year. The utility of the synchronized datasets produced by AWS Truepower for analyzing consumption and wind power patterns is significant. Having a good understanding of trends and correlations in the actual and forecast values of both of these parameters can lead to better choices in how the power system is planned and operated.

Potential Future Studies

One of the secondary benefits of the proposed project is that the model can be used for additional analysis that would be beneficial to a variety of stakeholders (e.g. Canada, the Atlantic Provinces, utilities). That analysis could examine the impact on unit commitment and dispatch costs of various policies, operational practices, generation investments, and transmission system changes. The following have been identified for the purpose of illustrating scenarios that could be studied in the future after the completion of the AEG work.

- 2020 with separate balancing areas but 15-minute scheduling (versus 60-minute today)
- 2020 with load forecast error and wind power production forecast error
- 2020 with load control
- 2020 with storage
- 2020 with more wind power (and quantification of incremental integration costs)
- 2020 with in-stream tidal power
- 2020 with various transmission & generation options
- 2040 with power system predicted by AEG
- 2010 but with Lepreau in service and price based dispatch of Quebec and New England interfaces.
- 2020 with various environmental constraint scenarios
- Analysis of value of adding flexible generation (eg combined cycle gas turbine)
- Any of previous but with no confidential data

Use of the full AEG model for other purposes would require new or renewed non-disclosure agreements with New Brunswick, Nova Scotia and Newfoundland and Labrador utilities.

Like all production cost studies, this balancing study complements, but is not a replacement for more technical reliability studies. Those studies would examine issues such as local voltage and transmission constraints, security of fuel supply, contingency analysis, and dynamic system performance.

Simulation Results

The following table contains some of the more relevant outputs of the simulation cases. The "Impact of Sharing" column is the difference between the respective common dispatch cases ("Two Areas" in 2010/11 and "One Area" in 2020) and the respective "Base" case as a percentage of the respective "Base" case.

Table 2 Simulation Results

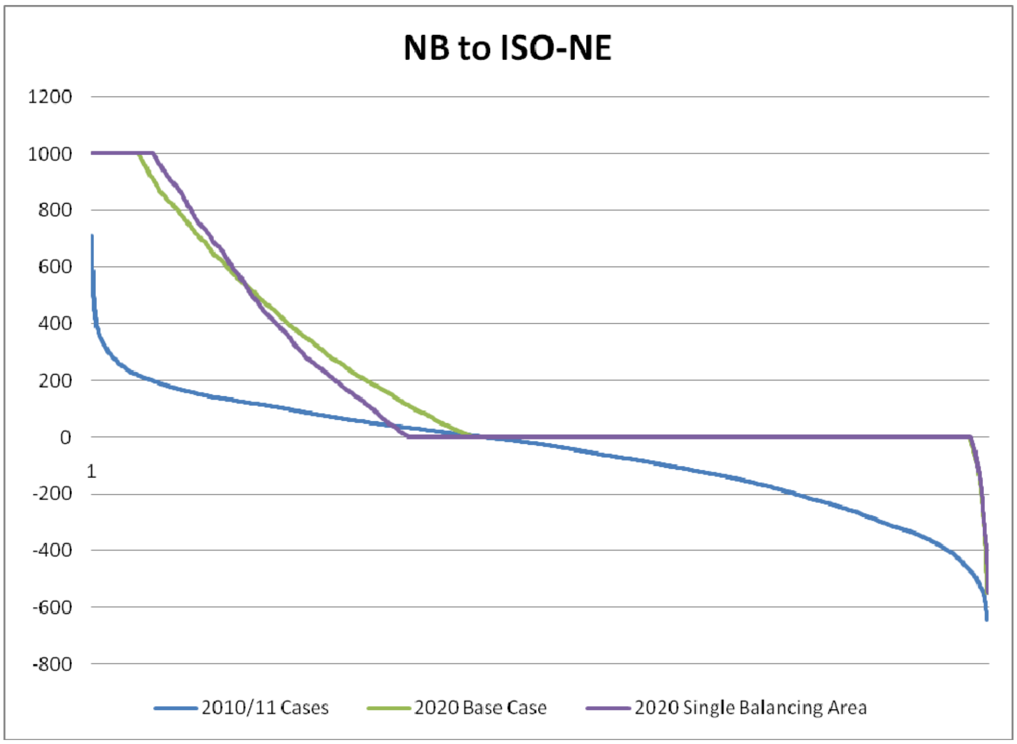
Measure	2010/11				2020			
	2010/11 Base (Three Areas)	2010/11 Two Areas	Impact of Sharing #	Impact of Sharing %	2020 Base (Three Areas)	2020 One Area	Impact of Sharing #	Impact of Sharing %
Costs $m	$840.8	$815.7	-$25.1	-3.0	$516.4	$508.5	-$7.9	-1.5
Start-up	$4.5	$3.8	$-0.7	-15.6	$1.8	$1.4	$-0.4	-22.2
Production	$836.3	$811.9	$-24.4	-2.9	$705.1	$643.4	$-61.7	-8.7
Imports	N/A	N/A	N/A	N/A	$6.3	$5.2	$-1.1	-17.4
Exports	N/A	N/A	N/A	N/A	$196.8	$141.5	$-55.3	-28.1
Start-ups #	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Nuclear	N/A	N/A	N/A	N/A	8	8	0	0
Coal	31	49	18	58	44	29	-15	-34.1
Oil	96	80	-16	-16.6	2	0	-2	-100
Natural gas	115	90	-25	-21.7	52	58	6	11.5
CT/Diesels	569	596	27	4.7	343	41	-302	-88
Production GWh	29,341	29,341	0	0	41,104	40,123	-980	-2.4
Nuclear	N/A	N/A	N/A	N/A	4,713	4,713	0	0
Coal	11,172	10,628	-544	-4.9	8,264	8,167	-97	-1.2
Oil	1,249	1,072	-177	-14.2	2	0	-2	-100
Natural gas	3,697	4,424	727	19.7	9,283	8,402	-881	-9.5
CT/Diesels	18	11	-7	-38.9	0.6	0.2	-0.4	-66.6
Hydro	9,261	9,262	1	0	13,449	13,449	0	0
Wind	2,048	2,048	0	0	3,484	3,484	0	0
Other	1,896	1,896	0	0	1,908	1,908	0	0
Net import GWh	4,332	4,332	0	0	-3,263	-2,283	980	N/A
Imports	4,891	4,891	0	0	88	81	-7	-8
Exports	559	559	0	0	3,351	2,364	-987	-29.5
Ancillaries Avg	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Regulation MW	48	34.3	-13.7	-28.6	58.2	35.7	-22.5	-38.7
Load Follow. MW	54.8	49.8	-5	-9.1	101	94.7	-6.3	-6.2

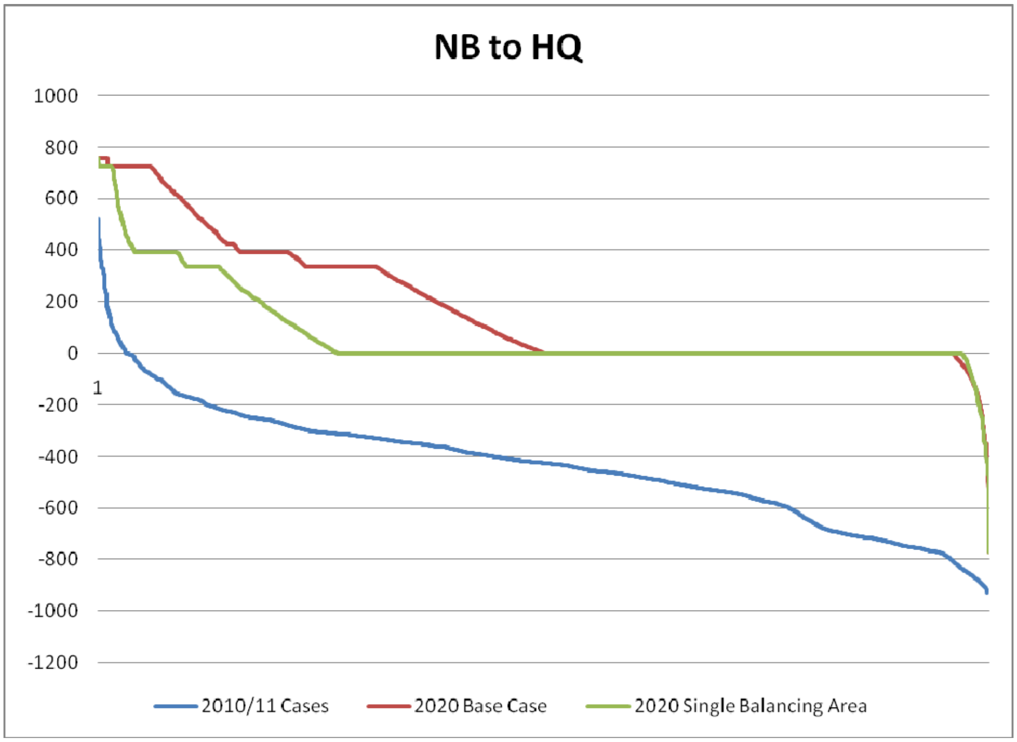
N/A = Not applicable

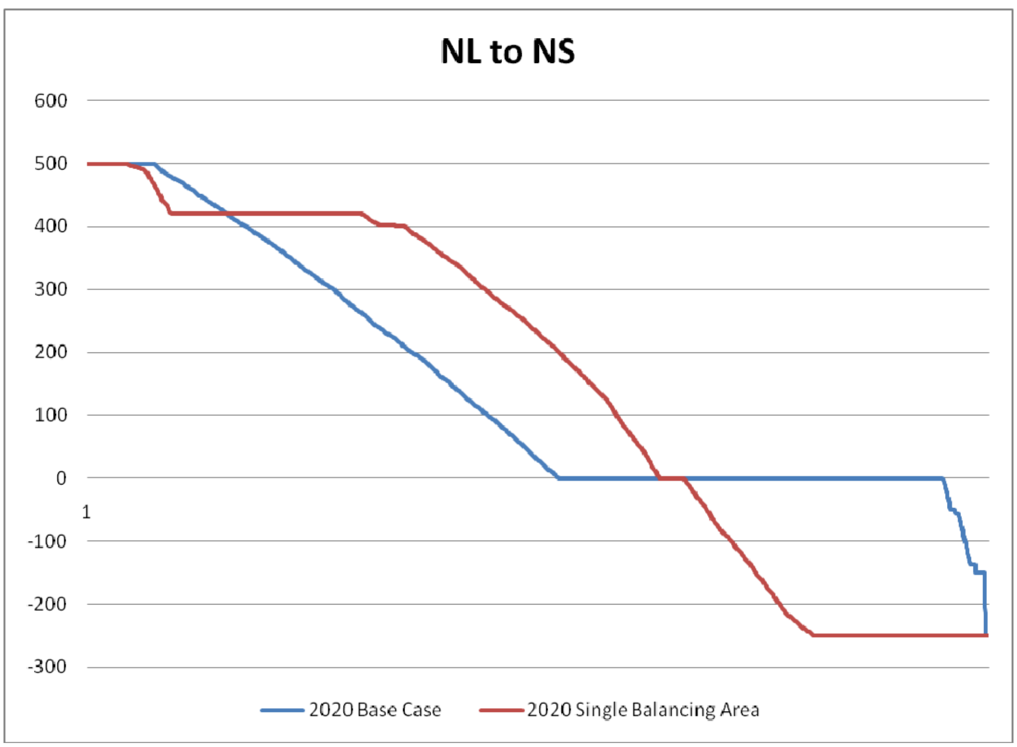
The following flow duration charts indicate the physical energy flows to and from external markets and between provinces in Atlantic Canada. The curves on each chart represent flows for the four cases studied as follows:

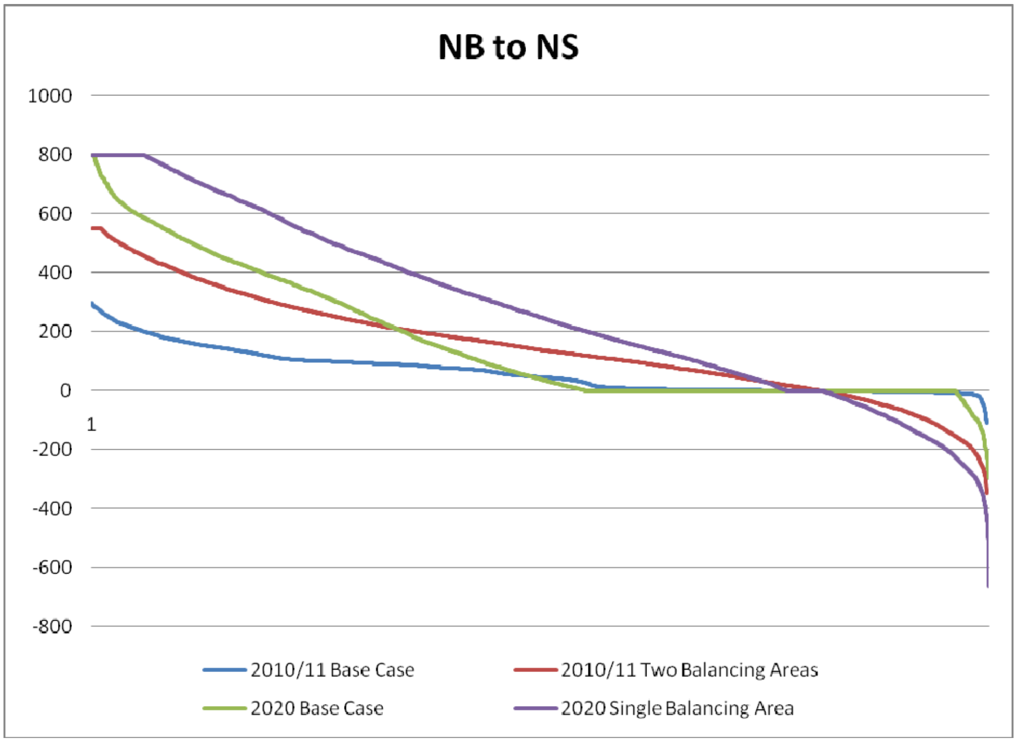
1. 2010/11 Base Case (separate dispatch and existing transmission)
2. 2010/11 Two Balancing Areas (common dispatch and existing transmission)
3. 2020 Base Case (separate dispatch and expanded transmission)
4. 2020 Single Balancing Area (common dispatch and expanded transmission)

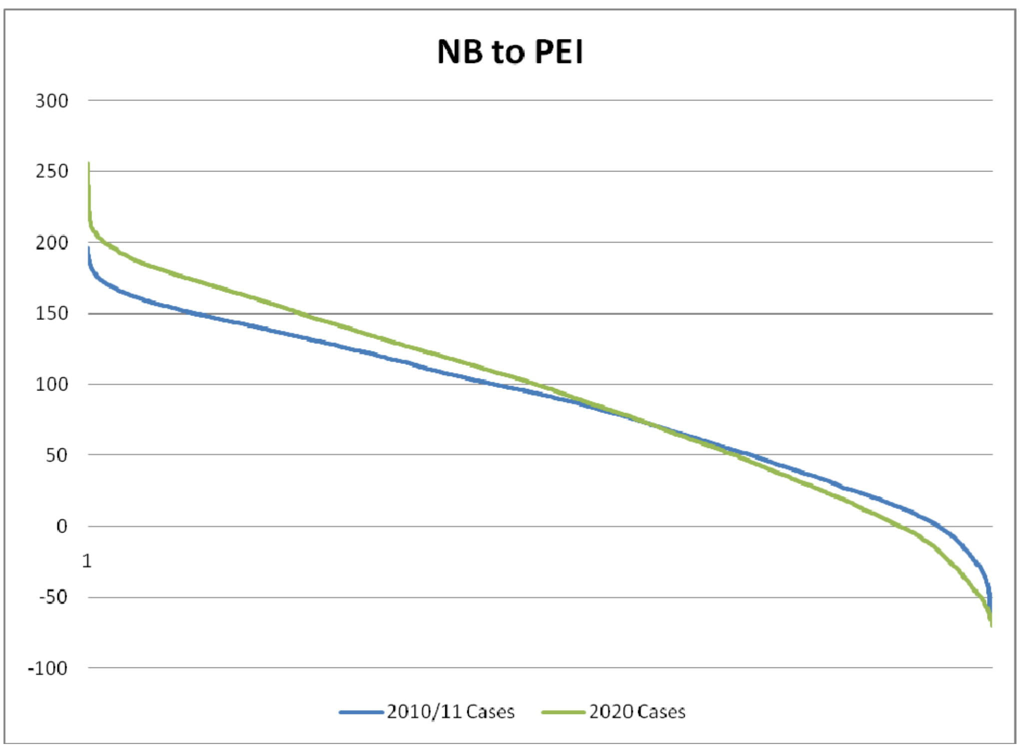
The horizontal axis is “number of hours” with the total number of hours in a non leap year being 8760. The vertical axis is “MW of flow” in the direction implied by the title of the chart. Each point on the curve indicates the number of hours in the year in which flows exceed the indicated MW value. The area under the curve but above the horizontal axis is the total flow in the direction implied by the chart title. The area above the curve but below the horizontal axis is the total flow in the opposite direction.




NB to HQ
1000
800
600
400
200
0
-200
-400
-600
-800
-1000
-1200
1
2010/11 Cases
2020 Base Case
2020 Single Balancing Area


NL to NS
600
500
400
300
200
100
0
-100
-200
-300
1
2020 Base Case
2020 Single Balancing Area


NB to NS
1000
800
600
400
200
0
1
-200
-400
-600
-800
2010/11 Base Case
2010/11 Two Balancing Areas
2020 Base Case
2020 Single Balancing Area


NB to PEI
300
250
200
150
100
50
0
1
-50
-100
2010/11 Cases
2020 Cases

Discussion of the Results

The simulation takes into account important factors such as significant transmission constraints, generation characteristics, and inter-area cost savings achieved through market-to-market transactions. The transmission constraints which were modelled are identified in Appendix 1. Generation characteristics are largely as provided by the respective utility and in many cases are confidential so are not included in this report. The impact of market-to-market transactions were taken into account so as to reduce the likelihood of overstating the potential savings of a common balancing function. The means by which this goal was achieved is described in Appendix 1 of this report.

Given the limited time available to complete the project and the additional complexities of doing so, uncertainties of generation contingencies, load forecast error, and wind power production forecast errors were not taken into account in the study. Such uncertainties increase the cost of unit commitment and dispatch because no unit commitment and dispatch algorithm can optimize to conditions that are not forecast. Nonetheless, the costs caused by these uncertainties would be less under a common balancing function due to diversity of the forecast errors and the availability of a broader portfolio with which to respond to contingencies and forecast error. Therefore, in this respect the actual savings in unit commitment and dispatch from a common balancing function would be even greater than shown in the results of this study.

It is also important to note that while this study looks at balancing supply and demand at a five-minute resolution, it does not consider reactive supply and voltage support, system stability, or contingency analysis. These would typically be considered in more detailed technical system impact and operational studies. Additionally, transmission losses and the optimization of losses and voltage levels are not taken into account in this study. A more comprehensive regional dispatch would take these factors into account and result in an additional source of savings. Savings arising from economies of scale are not part of this study either.

There are many additional factors that impact the level of the costs and therefore presumably also affect the savings of a common balancing function. Some significant factors are:

- Point Lepreau availability
- Hydro flows
- Wind power production
- Load characteristics (loss of load, changes in consumption patterns, etc.)
- Availability of additional balancing services (load control, more flexible imports, etc.)
- Flexibility of new generation
- Generation retirements

Due to the time and funding constraints, the sensitivities of the results to these and other factors were not studied. That being said, the model could be used to examine the impact of these factors in future study work.

As expected, the total cost of unit commitment and dispatch was less in the cases in which there was a common balancing function. The savings in the 2010/11 case was $25.1 million for the 12 month period. The savings in the 2020 case was $7.9 million. These represent savings of 3.0% and 1.5% respectively. As noted herein, these are merely order of magnitude values and are not necessarily representative for other years.

Similarly, the total requirement for regulation and load following was also less. Additional benefits of a common balancing function are expected to include less hydro and wind power being curtailed due to a short term energy surplus.

The reduced requirements for regulation and load following contribute to the reduction in the unit commitment and dispatch costs, but they also mean lower cost of having capacity that can provide these services. These capacity savings are estimated for each of 2010/11 and 2020 based nominally on the average of the unit costs that were used in deriving the New Brunswick, Prince Edward Island, and Nova Scotia tariff rates for these services.

Table 3 Regulation and Load Following

	2010/11	2020
Regulation		
Average Reduction in Requirements (MW)	13.7	22.5
Incremental Unit Cost ($/MW-h)	$3	$3
Total Savings ($million/year)	$0.36	$0.60
Load Following		
Average Reduction in Requirements (MW)	5	6.3
Incremental Unit Cost ($/MW-h)	$1	$1
Total Savings ($million/year)	$0.04	$0.06

The total savings of $25.5 million in the 2010/11 case and $8.6 million in the 2020 case are considered material given the total dollars involved and the margin of error in the inputs to the simulation and the nature of the simulation. This study analyzes savings, but it is also expected that higher levels of variable renewable resources (e.g. wind, solar, tidal) could be reliably integrated at less cost under a common dispatch model. Similarly, relatively inflexible cogeneration technologies (e.g. biomass or natural gas generation associated with industrial processes) could also be integrated at lower cost under regional balancing.

There are additional potential benefits of regional balancing that have not been quantified in this study. These include:

- Greater reliability due to diversity benefits and pooling of resources
- Fewer curtailments of zero cost zero emission energy (e.g. wind, hydro)
- Fewer interruptions of non-firm customers due to diversity benefits and pooling of resources
- Implementation savings arising from economies of scale

Appendix 1: Modeling Information and Data Assumptions

The following document captures some key assumptions used in the modeling, the modeling approach, and aspects of the data requirements.

Section 1:
Model Design Overview

The model is being built in Plexos modeling software. Any utility data provided in confidence is not to be used for other purposes or shared with other utilities without appropriate permissions. The model itself (excluding confidential data) will be the property of NBSO in accordance with the NBSO-NRCan Contribution Agreement. Any non-AEG use of the model must not be attributed to or otherwise associated with the AEG project.

The following design decisions have been assumed pending AEG review:

- Hourly unit commitment and dispatch to be done on a 5 minute resolution (for more details see Section 3)
- In the "Separate Balancing Area" cases there is a need to accurately represent market activities between the balancing areas
- Each province is represented as a *Region* (NB, NS, PEI, NL, QC, ME, NME, NE)
- Within each *Region* can be *Nodes* where:
    - *Nodes* are assumed to be a single bus where loads and generation are connected
    - *Nodes* are areas defined by transmission constraints
    - The following nodes are assumed:

Region	Node(s)
New Brunswick	New Brunswick
Nova Scotia	Nova Scotia
PEI	PEI
Newfoundland	Avalon Newfoundland West
Quebec	Hydro Quebec – Eel River (HQ-Eel River) Hydro Quebec – Madawaska (HQ-Madawaska)
Northern Maine	Northern Maine
New England	New England

- Northern Maine will be modelled on a simplified basis in 2010/11 and 2020 as:
    - Mars Hill wind farm (actual 2010/11, forecast 2020)
    - An aggregate load equal to exports (actual 2010/11, forecast 2020) from NB minus Mars Hill generation profile
    - An aggregate generator equal to imports (actual 2010/11, forecast 2020) to NB minus Mars Hill generation profile
- New England and Quebec will each be modelled on a simplified basis in 2010/11 as:
    - An aggregate load equal to exports from NB
    - An aggregate generator equal to imports to NB

- Interprovincial tie constraints are based on TTC since this is an energy dispatch analysis. These values were to be used unless the AEG determined more appropriate values. It was intended that the values used by the resource development group be adopted. Alternatively the study group could have established other values.
    - For the case of the NB to NS consideration was given to setting the value at the transfer capability that exists for x % of the hours, but this approach was not adopted.
    - The following constraints were assumed for 2010/11 (but are not applied in the cases in which actual flows are used):

Node From	**Node To**	**Summer TTC**	**Winter TTC**
New Brunswick	Northern Maine	No Constraint	No Constraint
Northern Maine	New Brunswick	No Constraint	No Constraint
New Brunswick	HQ – Eel River	335 MW	335 MW
HQ – Eel River	New Brunswick	350 MW	350 MW
New Brunswick	HQ – Madawaska	400 MW	435 MW
HQ – Madawaska	New Brunswick	391 MW	423 MW
New Brunswick	New England	1000 MW	1000 MW
New England	New Brunswick	550 MW	550 MW
New Brunswick	Onslow	550 MW	480 MW
Onslow	New Brunswick	350 MW	350 MW
New Brunswick	PEI	195 MW	200 MW
PEI	New Brunswick	200 MW	200 MW

- The following changes were assumed for 2020:

Node From	**Node To**	**Summer TTC**	**Winter TTC**
New Brunswick	Nova Scotia	800 MW	800 MW
Nova Scotia	New Brunswick	800 MW	800 MW
New Brunswick	PEI	350 MW	350 MW
PEI	New Brunswick	350 MW	350 MW
Newfoundland	Nova Scotia	500 MW	500 MW
Nova Scotia	Newfoundland	250 MW	250 MW

- Tie flows are to be treated:
  - As actual flows for 2010/11 case
  - As a combination of: predicted schedule, economic energy sales and tie drift (if practical in the modeling) for 2020 case
- Tie drift was to be modelled as a heavily constrained storage device
- New England and Quebec will each be modelled as a combination of a priced generator and a priced load (both hourly dispatchable) for the 2020 case
  - Pricing may contain “on peak” and “off peak” variations
  - A hurdle rate of $3/MWh is applied leaving Atlantic Canada and a hurdle rate of $16/MWh is applied entering Atlantic Canada in order to simulate the transactional costs (tariff, losses, administration, etc)
  - To be scheduled day ahead for 2010/11 and 2020 cases
- Nova Scotia and New Brunswick interface to be scheduled Day Ahead and allowed to float +/- 20MW for the Hour Ahead unit commitment
- Operating reserve capacity requirements on tie connections are respected
- AWS simulation of 2020 wind power production was conducted on a timely basis, so interim use of NBP and NSPI resource assumptions and scaling of historical production (on the assumption that the current wind regimes are relatively diverse and additional sites will not substantially increase diversity) was not required.
- The “2010/11” Study horizon is Aug, 1 2010 – July 31, 2011
- The “2020” Study horizon is Jan, 1 2020 – Dec 31, 2020

<u>Group Data Requirement:</u>

- Discussion was required to determine:
  - Hydro energy is represented as:
    - Daily limits for NB in 2010
    - Monthly limits for NL and NS in 2010
  - Monthly limits for NB, NL and NS in 2020

- The 2020 load profile was based on an extrapolated 2005 load profile. The 2005 load was selected to correlate with the ASW wind profiles
- Fuel Costs were provided by the individual utilities for 2010/11 and were provided by the resource development study for 2020.
- Emission constraints (Provincial caps and limits for NB/NS/NL/PEI)
  - CO_2, NO_x, SO_x, mercury

Utility Specific Data Requirement:

- Generation in each *Region*
  - Generator data as per a spreadsheet template.
  - Connection *Node*
  - Generation data for new facilities existing in 2020
  - Generation retirements before 2020
- Load for each *Node* at 5 minute resolution (2010/11)
  - If load for particular *Nodes* is unavailable, a percentage of total *Region* load
- Generation profile at 5 minute resolution (2010/11):
  - Wind generators
  - Self scheduled generation
- Hydro energy limits as identified in group discussion (2010/11)
- Generation outage and de-rate information for 2010/11
- Predicted forced outage rates and maintenance outages for 2020
- Tie capabilities between *Nodes* within *Region* as applicable(2010/11 & 2020)
- Flexibility of the DC ties
  - Maritime Link
  - Island Link
- Recommended location for future wind farms (2020)
  - Quantity of wind to be determined by resource development group
- Grouping of generation
  - Combining individual units to be dispatched as a single plant
- Ancillary service(s) requirements (see Section 2)
  - Services required
  - MW Quantity and/or formula used to define requirement
- Creation of a single ramp rate per facility in the case of facilities that have different ramp rates in different ranges in order to keep complexity of the optimization reasonable (avoiding impractically long solution times).
- Identification of "Non-firm" load quantities including specifics of ability to provide ancillary services. Note that the modeling tool has an "unserved load feature" that can be turned on or off. The initial assumption is that this feature is turned off.

If the above information was not provided/available assumptions were made based on generic data. Submission and use of confidential data is subject to appropriate NDAs and adequate time to complete the work within the AEG schedule.

Baselining of 2010/11 Against Actuals:

The following metrics will be used to assess how well the model simulates the actual dispatch that occurred in 2010/11.

- Number and timing of thermal generator start-ups
- Monthly fuel burn
- Annual unit capacity factor

Report Information:

- Explain assumptions for each case
- Caveats regarding limitations of assumptions, inputs and modelling approach

- Results to provide the following information:
  - Savings in unit hours of dispatch
  - Quantify number of starts and stops
  - Unit commitment and dispatch cost saving in orders of magnitude
  - Total regulation requirement
  - Total load following requirement
  - Capacity cost savings from reduced ancillary service provision (based on an assumed unit cost of the respective services)
- Results are to be reported for the region, as opposed to specific facilities, nodes or provinces
- Caveats regarding the “snap-shot” nature of the results and the hazards of extrapolation of the results
- Information on the use of the interfaces
  - Load duration curves for the interfaces between markets?
  - % of hours each interface is loaded beyond 95%
  - Average loading on each interface (defined for each direction)

Section 2: Capacity-Based Ancillary Service (CBAS) Requirements for AEG Balancing Study

CBAS Requirement Types:
1. AGC/Regulation
2. Load Following
3. Spinning Reserve
4. Supplemental Reserve
5. 30-min Reserve

The following table defines the CBAS regimes under each of the cases that are to be simulated.

	2010/11 Base (Three BAs)	**2010/11 Two BAs**	**2020 Base (Three BAs)**	**2020 One BA**
AGC (Regulation)	Each BA	Each BA	Each BA	The one BA
Load Following	Each BA	Each BA	Each BA	The one BA
10-Minute Spinning Reserve	Each BA but with reserve sharing between NS and NB/PEI/NMe BAs as described below.	Each BA	Each BA but with reserve sharing between NS and NB/PEI/NMe BAs as described below.	The one BA
10-Minute Supplemental Reserve	“	Each BA	“	The one BA
30 Minute Supplemental Reserve	“	Each BA	“	The one BA

1. AGC (Regulation) Requirement

AGC Requirement = Requirement for Loads + Incremental Requirement for Wind.

For the purpose of unit commitment and dispatch these two values are to be constants based on analysis of historical load and wind data and projections of future requirements. Each Balancing Area has its own requirement and must meet it from internal resources.

	2010/11 Base	**2010/11 Two BAs**	**2020 Base**	**2020 One BA**
NB/PEI/NMe	20.6 first 4 months, then 21.2	calculated	21.2	dna
NS	27	calculated	27	dna
NL	dna	dna	10	dna
NS/NB/PEI/NMe	dna	calculated	dna	dna
NL/ NS/NB/PEI/NMe	dna	dna	dna	calculated

The regulation requirements for combined BAs is to be equal to the square root of the sum of the individual BA requirements squared. This approach is based on the assumption that the regulation requirements are not correlated.

For example, the Regulation Requirement for NS/NB/PEI/NMe can be calculated as:

SQRT[(Regulation Requirement for NS)^^{2} + (Regulation Requirement for NB/PEI/NMe)^^{2}]

A generator's AGC (Regulation) capability is defined as its up or down 10-minute ramp capability constrained by its AGC range.

2. Load Following

LF Req. = Maximum of (5 Minute Load – Wind Power Production in Same Interval) - (Hourly Average Load - Hourly Average Wind Power Production) + Load Following Requirement for Schedule Changes on Regulated Interfaces

Each Balancing Area has its own requirement and must meet it from internal resources.

A generator's LF capability is defined as its ability to ramp up or down over 30 minutes.

The load following requirement for schedule changes was not modelled due to uncertainty of whether or not this component would be applied consistently in the region.

3. Spinning Reserve

General
Spinning Req. = MAX (0, ¼ * Largest Contingency – AGC Req – LF Req – Shared Spinning Reserve)

Largest Contingency = MAX (Largest Generator Contingency, Largest Intertie Contingency)

Largest Generator Contingency = MAX (The Largest Net MW Output of a Nuclear Generator or Thermal Generator Scheduled by MOD) and Dalhousie is treated as a single contingency, and 30 MW is added to Point Lepreau to account for no-load station service.

Shared Spinning Reserve = reduction to account for reserve sharing arrangement with at least one other BA.

4. 10-Minute Supplemental Reserve

Supplemental Req. (without exports) = MAX (0, 3/4 * Largest Contingency –AGC Req Not Used for Spin –LF Req Not Used for Spin – Shared 10 Minute Supplemental Reserve)

5. 30-Min Supplemental Reserve

30-min Supplemental Req = MAX (0, ½ * 2nd Contingency – AGC Req Not Used for Spin or 10 Min Supplemental – LF Req Not Used for Spin or 10 Min Supplemental - Shared 30-min Reserve)

6. Reserve Sharing

In the base cases the following reserve sharing approach is to be assumed. This approach is a reasonable simplified version of the current arrangement.

10-Minute Spinning
- NS carries 25 MW.
- The NB/PEI/NMe Balancing Area meets its reserve requirements for 10-minute spinning reserve in accordance with the generic formula above (but counts the full amount of the NS 10-minute spinning reserve as Reserve Sharing).
- NL has no reserve sharing.

10-Minute Supplemental
- NS carries 100 MW.
- The NB/PEI/NMe Balancing Area meets its reserve requirements for 10-minute supplemental reserve in accordance with the generic formula above (but counts the full amount of the NS 10-minute supplemental reserve as Reserve Sharing).

30-Minute Supplemental
- NS carries 50 MW.
- The NB/PEI/NMe Balancing Area meets its reserve requirements for 30-minute supplemental reserve in accordance with the generic formula above (but counts the full amount of the NS 30-minute supplemental reserve as Reserve Sharing).

Notes:

- No modelling of recallable export sales as those were no longer permissible in New England as of Dec 2010. Also, sales of this type were minimal in the months prior to this given the Point Lepreau outage.
- No modelling of imports or exports of CBAS (or reserve sharing outside of the Maritimes) as these were not occurring in the 2010/11 year and will not necessarily be feasible in future years.
- It is assumed that no ancillary services are provided by load in New Brunswick, Northern Maine, or Prince Edward Island. Provision of ancillary services by load in Nova Scotia were modelled at NSPI's direction.

AEG Balancing Study Ancillary Service Assumptions for 2020 Cases

The following ancillary service regime is assumed for the 2020 case.

2020 Base

- Each Balancing Area carries enough of each ancillary service (regulation, load following, 10 minute spinning, 10 minute supplemental, and 30 minute supplemental) to meets its own needs.
- The reserve requirements are based on each Balancing Area's respective source contingencies in accordance with the current NPCC Directory 5.*
- Assume existing reserve sharing between NB and NS continues. The following approach was considered but rejected based on as assumption of continuity. No reserve sharing agreement is assumed as (i) there is no guarantee that one will exist in 2020, (ii) if a reserve sharing agreement did exist in 2020 any assumptions on specifics would be entirely speculative, and (iii) benefits arising from reserve sharing would be a consequence of regional collaboration and therefore are within the scope of what we want to capture in this study.

2020 One Area

- The one Atlantic Canada Balancing Area carries enough of each ancillary service (regulation, load following, 10 minute spinning, 10 minute supplemental, and 30 minute supplemental) to meets its needs.
- The reserve requirements are based on the Balancing Area's respective source contingencies in accordance with the current NPCC Directory 5.*
- Tie usage will be reported and assessed with respect to how often ancillary services are constrained zonally. Studies taking into account zonal requirements are to be noted for possible future study. This approach may exaggerate the savings.

** Directory 5 requires:*

- *Spinning reserve equal to 25% of the largest source contingency in Balancing Area*
- *10 Minute Supplemental Reserve equal to 75% of the largest source contingency in Balancing Area*
- *30 Minute Supplemental Reserve equal to 50% of the second largest source contingency in Balancing Area*
- *Reserve associated with transactions across HVDC are the responsibility of the sinking Balancing Area for the transaction.*

New HVDC Contingencies: The Maritime link's two poles are each single contingencies so use 50% of the respective energy flow to take into account the possibility of operating mono-pole following the loss of the other pole. The Island Link contingency size is to take into account the nominal rating is 450MW/pole or 900MW total. In the event of the loss of a pole the remaining pole is capable of delivering 200% of its rating for 10 Minutes (900MW). In addition that pole will be capable of delivering 150% of its capability continuously (675MW).

Section 3: Market Operations Assumptions to Be Used for the AEG Balancing Study Modeling

	2010/11 Base (Three Areas)		2010/11 Two Areas		2020 Base (Three Areas)		2020 One Area	
	Day-Ahead Commitment	**Hour-Ahead Commitment & Dispatch**	**Day-Ahead Commitment**	**Hour-Ahead Commitment & Dispatch**	**Day-Ahead Commitment**	**Hour-Ahead Commitment & Dispatch**	**Day-Ahead Commitment**	**Hour-Ahead Commitment & Dispatch**
Dispatch Horizon	Upcoming 24 hours	Upcoming 1 hour	Upcoming 24 hours	Upcoming 1 hours	Upcoming 24 hours	Upcoming 1 hours	Upcoming 24 hours	Upcoming 1 hours
Look Ahead Horizon	Subsequent 24 Hours	Subsequent 3 hours	Subsequent 24 Hours	Subsequent 3 hours	Subsequent 24 Hours	Subsequent 3 hours	Subsequent 24 Hours	Subsequent 3 hours
Resolution	Hourly	5-minute for hour 1 and hourly for hours 2-4	Hourly	5-minute for hour 1 and hourly for hours 2-4	Hourly	5-minute for hour 1 and hourly for hours 2-4	Hourly	5-minute for hour 1 and hourly for hours 2-4
Areas	1. NB/PEI/NME 2. NS 3. NL	1. NB/PEI/NME 2. NS 3. NL	1. NB/PEI/NME/NS 2. NL	1. NB/PEI/NME/NS 2. NL	1. NB/PEI/NME 2. NS 3. NL	1. NB/PEI/NME 2. NS 3. NL	NB/PEI/NME/NS/NL	NB/PEI/NME/NS/NL
NB/Quebec Interface	Use the actuals at 5-minute resolution.	Use the actuals at 5-minute resolution.	Use the actuals at 5-minute resolution.	Use the actuals at 5-minute resolution.	Commit on economics subject to transmission constraint.	Dispatch on economics subject to transmission constraint.	Commit on economics subject to transmission constraint.*	Dispatch on economics subject to transmission constraint.*
NB/NE Interface	Use the actuals at 5-minute resolution.	Use the actuals at 5-minute resolution.	Use the actuals at 5-minute resolution.	Use the actuals at 5-minute resolution.	Commit on economics subject to transmission constraint.	Dispatch on economics subject to transmission constraint.+	Commit on economics subject to transmission constraint.*+	Dispatch on economics subject to transmission constraint.*+
NB/NS Interface	Use the actuals at 5-minute resolution.	Use the actuals at 5-minute resolution.	Commit on economics subject to transmission constraint.	Dispatch on economics subject to transmission constraint.	Commit on economics subject to transmission constraint.	Dispatch on economics subject to transmission constraint.+	Commit on economics subject to transmission constraint.	Dispatch on economics subject to transmission constraint.
NL/NS Interface	Does not exist in this timeframe.	Does not exist in this timeframe.	Does not exist in this timeframe.	Does not exist in this timeframe.	Commit on economics subject to transmission constraint.	Dispatch on economics subject to transmission constraint.	Commit on economics subject to transmission constraint.	Dispatch on economics subject to transmission constraint.

Notes:

+ Allow deadband (of +/- 50 MW for NB/NE interface and +/- 20 MW for NB/NS interface) around the nominal hourly tie flow.

Modeling approach taken with the Plexos tools in order to simulate the assumptions noted above:

- Sequential solving of (i) Day-ahead commitment taking inter-market actuals into account as noted above, and (ii) Hour-ahead commitment and dispatch taking inter-market actuals into account as noted above.
- The Day Ahead commitment looks at the upcoming 24 hour calendar day at an hourly resolution, and with an additional 24 hours considered as a look-ahead (also at hourly resolution).
- The unit commitment for certain generation from the Day-Ahead will be locked in for the Hour-ahead commitments. That is, the output of the Day-head run will define which generators are committed. The Hour-ahead run will, in the case of generators that are set-up to inherit the Day-ahead commitment, get the commitment status from that Day-ahead output file.
- The Hour-ahead run optimizes the upcoming hour at a 5-minute resolution and also looks ahead another 3 hours with an hourly resolution. The purpose of the four hour view is to make a better decision on additional unit commitments and on dispatch given the existence of slow-moving generators. The next hour's run will then overwrite the values from hours 2, 3 and 4. The Hour ahead optimization will be done in two passes, with the first one establishing the nominal hourly flows when appropriate (in accordance with the table above).

Atlantic Energy Gateway

Resource Development Modelling Study

A Study of Potential Savings for the Combined Resource Planning of Atlantic Canadian Utilities

March 2012

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Atlantic Energy Gateway Resource Development Modelling Study Report

A Study of Potential Savings for the Combined Resource Planning of Atlantic Canadian Utilities

Executive Summary

The Atlantic Energy Gateway (AEG) project is a regional initiative of the federal government, the Atlantic provincial governments, electric utilities of Atlantic Canada and the system operators in New Brunswick and Nova Scotia. The objective of the AEG project is to contribute to the development of Atlantic Canada's clean energy resources by identifying the opportunities and assisting in evaluating the advantages of the region's substantial and diversified renewable energy potential for wind, tidal, biomass/biofuels, and hydro.

The AEG is focused on contributing to identifying greater regional cooperation, benefits, and efficiencies among the various participants in the electricity and clean renewable energy sectors. This particular study was conducted by ABB Technology Ltd (Ventyx) under the direction of the Resource Development Modelling Committee of the AEG. It was undertaken at the request of the AEG Steering Committee and has involved collaborative efforts by the Governments of Canada, the Atlantic Provinces and the Atlantic region electric utilities. This document is the final report of the AEG - Resource Development Modelling Committee.

The fundamental hypothesis behind this study is that benefits can be achieved by regional planning of future electric generating resources rather than planning separately as is done today. Each of the Atlantic utilities currently develops an integrated resource plan (IRP) for its medium and long term future generation development. The objective in this study was to model a more integrated view of the region and determine the economic and environmental benefits compared to the individual provincial models.

Resource development planning identifies the long term optimization of power system supply, demand and transmission resources to meet projected reliability, environmental and economic targets. To achieve the study results, an optimization computer simulation tool called *Strategist®* was used. NB Power, NS Power and NL Hydro currently utilize *Strategist®* and had developed a partial Atlantic simulation model to evaluate the Muskrat Falls portion of the Lower Churchill hydro development entering the region, including the transmission links from Labrador to Newfoundland and from Newfoundland to Nova Scotia. By adding PEI and Northern Maine to this existing model plus revised representations of the Hydro Québec and ISO New England markets, a more detailed expansion simulation was developed for Atlantic Canada.

Study parameters and assumptions were developed by the Resource Development Modelling Committee with assistance from Ventyx. Commercially sensitive confidential utility data was

supplied directly to Ventyx and protected via non-disclosure agreements. Ventyx executed the *Strategist®* model to recreate the proposed IRPs of the four provincial utilities and then compared the sum of their costs against the costs of operating the combined Atlantic region. All of the resource development options particular to each utility's IRP were available in the analysis which included the renewable energy potential for wind, tidal, biomass, and hydro plus nuclear and natural gas options. Several environmental regulations were included as development constraints. These included: renewable energy standards, SO_2 and NO_x requirements for each province, CO_2 emission reduction to 5 Mte by 2020 in Nova Scotia and the federal requirement for coal fired power plants to emit CO_2 equivalent to a combined cycle natural gas plant or better or retire after a 45 year life. In this study, coal fired power plant retirement was assumed for New Brunswick but an equivalent cap of 5 Mte by 2030 and 4.5 Mte by 2040 was assumed by Nova Scotia. While this does not exactly match the profile of the CO_2 emission cap of the proposed equivalency agreement between the province of Nova Scotia and the federal government related to the GHG Regulations (as these limits were still under negotiation during this study work), this assumption is sufficiently close to give confidence in the results.

The systems were simulated in detail for the study period of 2015 through 2040 with the capital costs of each new generation resource charged at its escalating economic carrying cost. This approach treated projects of differing lives within the study period on a level playing field and eliminated the need to conduct an end effects analysis beyond 2040. Analysis was completed to determine Least Cost resource model results for a reasonable forecast of future conditions (Base Case scenario), for a High Natural Gas Price future, for a Low Load future and a scenario with Limited Transmission Expansion between NB and NS. In each of these cases (except for the Limited Transmission Expansion), expansion of the NB-PEI and NB-NS interconnections was assumed to be increased significantly above current transfer levels and the cost of the assumed transmission expansion is not included in the resource models. In addition to Least Cost model results several "Plans of Interest" were selected to reflect development strategies that focused on Natural Gas, Nuclear in NB and High Renewable Penetration if these were not part of the least cost model. These resulting models were subsequently simulated in greater detail to determine annual energy sources and emission levels. The results of the net present value (NPV) analysis of resources options are provided in Figure 1.

A number of resource options (Lower Churchill project for NL Hydro, Lower Churchill participation for NS Power and Grand Falls Redevelopment and Coleson Cove units 1 and 3 conversion to natural gas) are committed in the provincial base case as part of their IRP's and by such their costs and benefits relative to existing resources today are not captured in these model results.

Figure 1
NPV Costs of Different Resource Development Plans
($Millions)

	Sum of Standalone Provincial Systems with Existing Transmission			Combined Regional System with Expanded Transmission			Combined Regional
Scenarios:	Base Case	High Gas Price	Low Load	Base Case	High Gas Price	Low Load	Limited Transmission
Plans of Interest:							
Nuclear (least Cost)	**$22,395**	**$24,228**	**$17,730**	**$21,516**	**$23,199**	**$17,146**	**$21,608**
Natural Gas	**$22,453**	**$24,465**	**$17,769**	**$21,624**	**$23,534**	**$17,232**	**$21,710**
High Renewable	**$22,408**	**$24,475**	**$17,769**	**$21,635**	**$23,541**	**$17,249**	**$21,718**

In viewing these modeled potential resource results the reader is cautioned that they are indicative and directional in nature. Simulation of power system expansion over a period of 30 years is an approximate exercise subject to many assumptions. The optimization model results were derived from the assumption set and hold true only to the extent that the assumptions are accurate. It is important to understand that the results are not the total revenue requirement for the region but only the costs of fuel, optional new generation O&M and capital, and new generator interconnection capital. There is no consideration of any existing or future costs for in province distribution and transmission and there is no consideration of capital for existing generation resources. It is generally accepted that these will be common across the Cases and net-out of the comparative analysis. Finally, the opportunity to achieve NPV benefits resulting from combined regional planning have not been segregated by province. Opportunities are shown from an Atlantic region perspective only.

Comparison of the different resource scenarios and development plans provided the following findings:

> The Nuclear in NB plan, based on cost assumptions, is the least cost expansion for the Base Case scenario and the combined regional resource plan is $879 million less cost than the sum of the separate provincial plans. This resource benefit is sufficient to pay the cost of the transmission expansions estimated at $565 million in 2015 and provide a net benefit to the ratepayers of the region of $314 million. The primary development components, other than Nuclear in NB in 2038, are 114 MW of wind in NS in 2015, three small hydro projects in NL in 2019, 2021 and 2023, a 250 MW combined cycle gas unit in NS in 2030, a 400 MW combined cycle gas unit in NB in 2032 and a 130 MW combined cycle gas unit in PEI in 2033. The higher gas price in the High Natural Gas Price scenario makes the nuclear plan even more economic than the Base Case Scenario and the regional plan has a NPV benefit of $1029 million (net benefit of $464 million) compared to the High Gas stand-alone provincial plans. Other than installation of 100 MW of wind in each of NS in 2035 and NL in 2039, this High Gas Scenario has the same combined regional resource expansion plan as the Base Case.
>
> In the Low Load Scenario the least cost plan is still the nuclear expansion but with the combined regional resource NPV benefits reduced to $584 million (net benefit of $19 million). The Low Load Scenario development plan is similar to the Base Case except that a 400 MW combined cycle gas unit in NB was deferred from 2032 to 2039.
>
> The Limited Transmission sensitivity reduces transfer capabilities from the Expanded Transmission Cases and increases the NPV cost of supply resources by $92 million compared to the combined regional system Base Case. The expansion plan is the same as the High Gas plan except that the 100 MW of wind in NL is delayed from 2039 to 2040. The wind in NS and NL occurs because the limited interconnection reduces the opportunity for economy transfers from NB to NS so it is needed to enable NS to operate within its CO_2 cap.

The value of any development plan is not just measured in financial differences. Given the global concerns regarding climate change and associated policies to reduce greenhouse gas (GHG) emissions, the amount of emissions from a particular plan is extremely important. Under the Expanded Transmission Base Case, overall regional emissions are reduced by 64% from 2005 levels.

The relative energy mix in a resource development plan is also of interest, not just because of its influence on emissions, but also from the perspective of diversity of fuel source risk and fuel price volatility. Fuel sources of coal and oil are imported and depend on world markets for cost and availability while wind and hydro are local and natural gas is currently an indigenous resource (though subject to international market pricing). In the Expanded Transmission Base Case the large increase in hydro by 2020 combined with natural gas and a large nuclear after 2030 reduces coal and oil generation from its 49% share in 2005 to only 6% by 2040.

Preliminary estimates have determined that the cost of the two transmission expansions between NB-PEI and NB-NS is $565 million in 2015. With an Expanded Transmission Base Case resource benefit of $879 million the transmission can be paid for and still provide $314 million of benefit for regional ratepayers. However, the Limited Transmission Sensitivity suggests a benefit of $787 million. These preliminary estimates require further analysis and would need to be confirmed through a comprehensive transmission study. While this particular Sensitivity assumed no expansion of the existing transmission interties, based on current system operating conditions transmission expenditures will be necessary to maintain the present transfer limits into the future. Accordingly, the benefit of the Limited Transmission Sensitivity is somewhat inflated. Regardless, the resource benefits derived in this study are only one component of total benefit of transmission and the other considerations (reliability) need to be analysed and understood prior to any commitment to expand the interconnections. In short, more detailed transmission analysis work is required and it must be integrated with additional resource analysis in order to determine an optimum expansion plan for the region.

While much of this discussion has been focussed on the benefits derived in the model, important areas for policy consideration which establish the winning conditions for renewables described in the modeling are as follows:

- <u>Natural Gas Supply and Infrastructure</u> - This resource modeling study shows increased use of natural gas for electricity generation in all scenarios examined. Development of a long-term regional plan focussed on security of natural gas supply and pipeline infrastructure needs would help ensure that the region could enjoy the forecasted cost and the air emission benefits of natural gas generation.

- <u>Enhanced Transmission Interties</u> - Transmission transfer capacity within the region promotes the sharing of renewable resources and is an important enabler of regional cooperation. There are significant transmission expansion decisions to be made in the near- to mid-term. A finding of this resource modeling study is that additional transmission analysis is required by the utilities in order to determine an optimal plan for transmission intertie expansion within the region.

- <u>Hydroelectric Power</u> - Hydroelectric generation grows to approximately 45% of the region's electricity supply by 2040. Hydro provides renewable energy but, equally important, it can supply valuable regulation and load following capacity which is a critical enabler of wind and tidal generation. Efforts to promote new and protect existing hydro generating resources are important to allow the progress of other renewables in the region.

Background

The Atlantic Energy Gateway ("AEG") is an Atlantic Canada electricity and clean renewable energy project funded and coordinated by the Federal Government Department of Natural Resources Canada ("NRCan") and The Atlantic Canada Opportunities Agency ("ACOA"), with participation from the Governments of New Brunswick ("NB"), Prince Edward Island ("PEI"), Nova Scotia ("NS"), and Newfoundland and Labrador ("NL"); four of the region's major electrical utilities: New Brunswick Power Group of Companies ("NB Power"), Maritime Electric Company Limited ("MECL"), Nova Scotia Power/Emera Inc. ("NS Power"), and Nalcor/Newfoundland and Labrador Hydro Corporation ("NL Hydro"); and the region's two system operators, New Brunswick System Operator ("NBSO") and Nova Scotia Power System Operator ("NSPSO").

The AEG is focused on contributing to identifying greater regional cooperation, benefits, and efficiencies among the various participants in the electricity and clean renewable energy sectors through increased collaboration, discussion and analysis of existing utility assets, and future requirements including additional clean and renewable energy resources for regional and export purposes.

The AEG participants have worked collaboratively over the past two years sharing existing information pertaining to the electricity systems, development of Atlantic Canada's clean and renewable energy resources, and where necessary, undertaking new analysis to improve the understanding of the region's electricity industry.

Some of the major components of the AEG work included: workshops on individual energy components in each of the four Atlantic Provinces; working committees on functional sectors such as transmission, resource generation, system operations; meetings and conference calls; participation by industry experts; and a number of professional external studies designed to provide a strategic and factual foundation on topics such as renewable energy financing, renewable energy R&D, supply chain development, and a study of the Eastern Canada and Northeast United States marketplace for electricity.

This ***Resource Development Modelling Study*** is one of those professional external studies with the purpose of determining if there are long term economic and environmental benefits arising from the coordination of planning the development of regional generating assets compared to planning within the utilities current provincial jurisdiction. Resource development planning is a complex iterative process that needs technical skill sets supported with specialized computer simulation models to determine optimization of power system supply, energy demand profiles and transmission infrastructure. The operational requirements are established by the market rules, procedures and tariffs applicable to the operation of the systems under study. The issues of reliability, environmental emission targets and economic targets influence the rules established by government policy and regulators.

A Resource Development Modelling Technical Committee (comprised of modelling experts from the modeling consultant Ventyx, the Atlantic utilities, and independent consultants) provided advice to the Steering Committee of government officials. The committee selected technical support from Ventyx through consultation with utilities, consultants and experts because of their current role of providing similar services to the regional utilities and professional reputation. This Technical Committee developed terms of reference for the study implementation and provided necessary data and technical support to Ventyx for the modelling work. Each utility entered Non-Disclosure Agreements with Ventyx to protect data and detailed study results deemed to be commercially sensitive.

Study Approach

Overview

Each of the regional utilities currently develops an integrated resource plan (IRP) for its medium- and long- term future generation and transmission development. These IRPs are often reviewed by provincial regulators and, although the results are made public through the regulatory process, confidential data is withheld from public scrutiny. The approach in this study was to develop a potential regional IRP and determine the economic and environmental savings from taking a regional planning and development approach.

To do so required that a regional simulation model be developed so that its IRP profile could be compared to the sum of the individual utility IRPs. The terms of reference sought a model that would determine the least cost base case plan as well as plans that integrate increasing amounts of clean, renewable and non-emitting energy sources for varying domestic and export loads. The modelling approach followed three steps as follows:

- Simulation Model Development and Database Adaptation
- Base Case Analysis
- Sensitivity Analysis

Progress and results were reported by Ventyx to the Technical Committee on a continuous basis and updates were provided to the Steering Committee at the conclusion of each phase.

Simulation Model Development and Database Adaption

An IRP involves a computer optimization simulation tool that selects a set of generation expansion options at future years that will result in the least net present value (NPV) cost for the selected time period. This requires detailed modelling of projected generation construction and operation and associated costs for the study period (2015 to 2040 for this study). It also requires consideration of the economic value of the model results beyond the study period because power system generators have very long and differing length lives (in this study the economic carrying charge method was used to deal with this issue). The generation related options available (wind, biomass, tidal, natural gas, nuclear, demand side management, etc.) can be numerous with varying sizes.

The foundation for the simulation model was established using the base model for each utility including the existing systems and the commitments already made respecting future generation sources. This enabled the optimization simulation to operate efficiently and produce feasible model results for generation development in the region. For this study screening was done collaboratively by the Technical Committee and the detailed development plan modelling was completed by Ventyx with its *Strategist*® IRP optimization tool for plan development.

The existing data sets from the three regional utilities that license *Strategist*® (NS Power, NB Power & NL Hydro) formed the basis of the regional model, and were supplemented with data for PEI. Market data for Quebec, New England and Northern Maine were included as well. The Technical Committee reviewed common data and adjusted where necessary to create a consistent dataset for the region. Confidential data (such as heat rates of existing units, unique parameters of a new option, etc.) were provided directly to Ventyx by each utility and protected via the non-disclosure agreements. Ventyx reviewed this confidential data and provided assurance to the Technical Committee that it was reasonable and consistent. Adjustments to necessary items were made by Ventyx in confidence through discussions with the utility owning such data.

It should be noted that *Strategist®* is not a transmission optimization model. Accordingly the Technical Committee made assumptions about existing and expanded transmission capability, particularly related to transmission interties between companies. These assumptions were evaluated in relation to utility import and export outputs from the model.

The *Strategist®* database was used to conduct PROVIEW module optimization runs that generated multiple resource development models and their associated NPV costs. Because PROVIEW does not store all the information of interest for every plan that it produces greater detail on specific models were generated by the Generation And Fuel (GAF) module to provide annual generation, cost and emissions results.

Base Case Analysis

The Base Case was based on the projected load, fuel and market prices, and generator cost and performance parameter updates deemed necessary by the participating provincial utilities. The following assumptions were also included:

- 45 year retirement of coal plants in New Brunswick
- CO_2 emission hard caps to 2030 and beyond for Nova Scotia in alignment with the assumed provisions of an equivalence agreement with Environment Canada
- Natural gas prices based on current futures and the US Energy Information Agency outlooks with appropriate tolls applied (forecast derived with information available in December 2011)
- Load forecasts and generating options
- For the combined system, 500/250 MW transfer capability between NL-NS, 800 MW between NS-NB and 350 MW between NB-PEI
- For the individual system runs the existing intertie transfer capabilities were used for NB-NS and NB-PEI (although the NS import from NB was reduced to 100 MW to better reflect the limitations that have emerged on this interface)

Running the Base Case required five separate PROVIEW optimization runs: one for each of the four provincial models with plan optimality and rankings selected on the basis of what is best for a single province and a final combined optimization model with the plans optimized across the entire region. For the individual provincial models it was necessary to “fix” the future resource plans for the remaining three provinces. The “fixed” plans used were the same models that resulted from the separate databases before combining them.

The Base Case output from PROVIEW produced numerous potential generation development scenarios from which was identified the models most in line with the development strategies of – least cost plan, natural gas expansion, high renewable expansion and nuclear expansion. Once these models were selected, GAF runs of each model were completed to determine more detailed energy utilization, cost and emission impacts by year.

Sensitivity Analysis

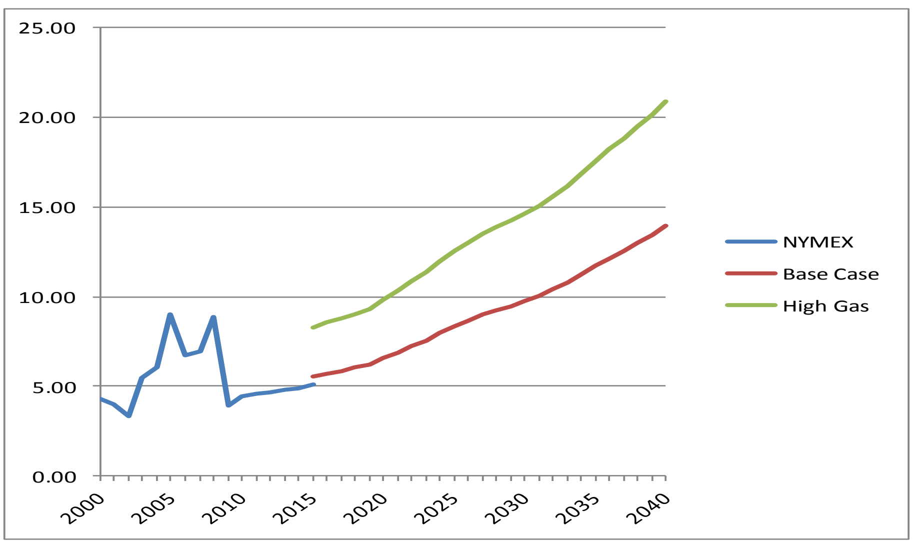
A sensitivity analysis was conducted against the Base Case Scenario to produce a High Natural Gas Price Scenario and a Low Load Growth Scenario for both individual provinces and combined regional system models. A separate model of a Limited Transmission Scenario was undertaken for the combined regional model to assess the impact of transmission restrictions. The primary focus in the sensitivity analysis was to determine the least cost plans for all scenarios and compare resulting NPV costs to the base case. The computer simulation runs required for the various scenarios are provided in Figure 2.

Figure 2
Resource Development Modelling Study Computer Model Runs

	Standalone Provincial Systems with Existing Transmission Interties			Combined Regional System with Expanded Transmission Interties			Combined System: Limited Trans-mission
Scenarios (Proview Runs)	Base Case	High NG Price	Low Load	Base Case	High NG Price	Low Load	
Plans of Interest: (Devel. Themes)	1A Least Cost	2A Least Cost	3A Least Cost	4A Least Cost	5A Least Cost	6A Least Cost	7A Least Cost
	1B Gas	2B Gas	3B Gas	4B Gas	5B Gas	6B Gas	7B Gas
	1C High Renewable Penetration	2C High Renewable Penetration	3C High Renewable Penetration	4C High Renewable Penetration	5C High Renewable Penetration	6C High Renewable Penetration	7C High Renewable Penetration
	1D New Nuclear in NB	2D New Nuclear in NB	3D New Nuclear in NB	4D New Nuclear in NB	5D New Nuclear in NB	6D New Nuclear in NB	7D New Nuclear in NB

The High Natural Gas Price Scenario applied the same assumptions as the Base Case except that it increased natural gas prices by 50% as shown in Figure 3.

Figure 3
Natural Gas Prices ($/MMBtu)



The objective with this High Natural Gas Price case was to determine the relative impact of low capital cost generation with high fuel risk (gas combined cycle) compared to high capital cost generation options with low fuel risk (wind and nuclear). Figure 3 illustrates the natural gas prices used for the sensitivity (high gas) and base case analyses. Note that historic and projected NYMEX prices at Henry Hub are provided for 2000 through 2015. The prices shown for the Base Case are the annual average natural gas prices from the Annual Energy Outlook 2012 produced by the Energy Information Agency of the US Department of Energy, with a basis differential adder of $0.45/MMBtu for pipeline transportation between Henry Hub and the Maritimes. In the actual modelling these were applied at 95% for summer (April-October) and 110% for winter

(November-March). This seasonal differential reflects both the seasonal nature of NYMEX price variation and especially the seasonal basis differential for pipeline congestion.

The High Gas price was also applied at 95% for summer and 110% for winter. It is worth noting that the natural gas prices applied in the study may seem high considering the current low price of natural gas at Henry Hub (recently in the $2.50/MMBtu range). This current low price is considered an anomaly by industry because of a number of factors (unusually warm winter, high storages, high value of wet gas liquids, locked in discoveries). The forward prices are much higher and consistent with the forecasts of the Energy Information Agency of the US Department of Energy. The High Gas price is not necessarily just a potential price increase at Henry Hub it also could result because of Atlantic Canada supply shortages such that additional basis differential would need to apply to procure natural gas from the Boston area and transport it north.

The Limited Transmission Scenario applied the same data as the Base Case except that the NB-NS interconnection was reduced from 800 MW to the existing interconnection capacities and the NB-PEI interconnection was reduced to the existing 200 MW capacity. The objective here was to determine if less transmission transfer capability (with less cost) may still achieve enough regional benefits to be a more economically attractive approach.

The Low Load Growth Scenario was completed with all the same data as the Base Case except for a lower load for each province. This reflected the potential load impacts of lower economic growth and assuming potential loss of some large industrial loads which would result in reduced energy demand/sales and reduced generation capacity requirements. The impact of higher load growth was also examined but not in detail during the regional analysis.

Summary of Results

The results of the NPV analysis of resources options produced by PROVIEW are provided in Figure 4. Note that a number of resource options (Lower Churchill project for NL Hydro, Lower Churchill participation for NS Power and Grand Falls Redevelopment and Coleson Cove units 1 and 3 conversion to natural gas) are committed in the provincial base case as part of their IRP's or commercial arrangements and as such their costs and benefits relative to existing resources today are not captured in these model results.

Figure 4
NPV Costs of Different Resource Development Plans
($Millions)

	Sum of Standalone Provincial Systems with Existing Transmission			Combined Regional System with Expanded Transmission			Combined Regional Limited Transmission
Scenarios:	Base Case	High Gas Price	Low Load	Base Case	High Gas Price	Low Load	
Plans of Interest:							
Nuclear (least Cost)	$22,395	$24,228	$17,730	$21,516	$23,199	$17,146	$21,608
Natural Gas	$22,453	$24,465	$17,769	$21,624	$23,534	$17,232	$21,710
High Renewable	$22,408	$24,475	$17,769	$21,635	$23,541	$17,249	$21,718

In viewing these results the reader is cautioned that these are indicative and directional in nature. Modelling of power system demand, costs and expansion needs 30 years into the future is an approximate exercise subject to many assumptions. It is also important to understand that the results are not the total revenue requirement for the region but only the costs of fuel, generation Operations and Maintenance (O&M), new generation capital cost funding and new interconnection capital cost funding. Therefore these model outcomes are best used for comparative purposes, case to case, rather than as expressions of total system costs. Additionally, it must be noted that there is no consideration of any existing or future costs for in province distribution and transmission and there is no consideration of capital for existing generation resources. These exclusions are considered appropriate as they would be largely common across the cases. Finally, the opportunity to achieve NPV benefits resulting from combined regional planning have not been segregated by province. Opportunities are shown from an Atlantic perspective only.

The following sections analyse these results in greater detail.

Base Case Analysis Results

The Base Case analysis projected the sum of Net Present Value (NPV) costs of current standalone provincial IRP implementation compared to a combined regional IRP to determine if there were potential benefits. As shown in Figure 5 the Least Cost regional plan included the Nuclear unit in NB with a 2015 NPV benefit of $879 million. Given that the transmission upgrades to the NB-NS and NB-PEI interconnections that were assumed in the analysis are projected to cost[1] about $565 million, a combined regional plan with the transmission upgrades completed by 2015 can pay for the transmission and still produce $314 million in savings for ratepayers.

Figure 5
Base Case NPV Results
($Millions)

Plans	Standalone Provincial Systems with Existing Transmission Interties	Combined Regional System with Expanded Transmission Interties	Differences
Nuclear in NB (Least Cost)	$ 22,395	$ 21,516	$ 879
Natural Gas	$ 22,453	$ 21,624	$ 829
High Renewable	$ 22,408	$ 21,635	$ 772

The value of an alternative development plan is not just measured in financial differences. Given the global concerns regarding climate change and associated policies to reduce greenhouse gas (GHG) emissions, the amount of emissions from a particular plan is extremely important. Figure 6 plots the annual regional GHG emissions[2] over the study period for the regional Least Cost – Nuclear in NB case and compares them to actual emissions in 2005 and 2010. Overall regional emissions are reduced by 64% from 2005 levels.

1 The cost estimates for the transmission upgrades are detailed in the "AEG Transmission Modelling Study Report."

2 GHG emissions in the power sector are composed almost entirely of CO_2 from combustion of fossil fuels and are measured as tonnes of CO_2 equivalent.

Figure 6
Base Case Nuclear Plan Emissions
(Tonnes of CO_2)

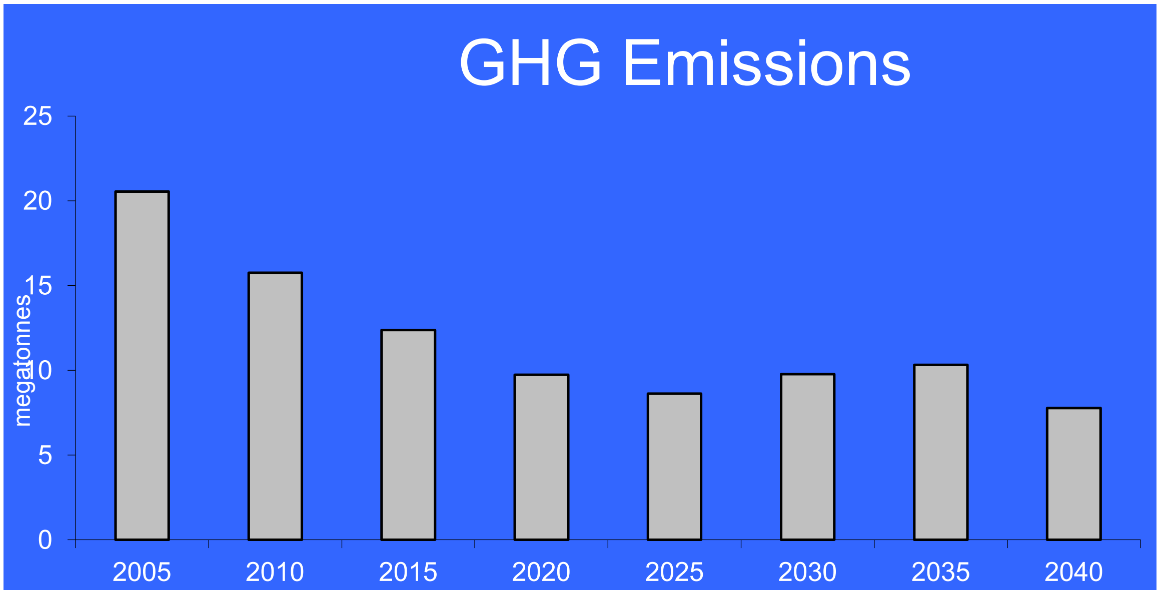
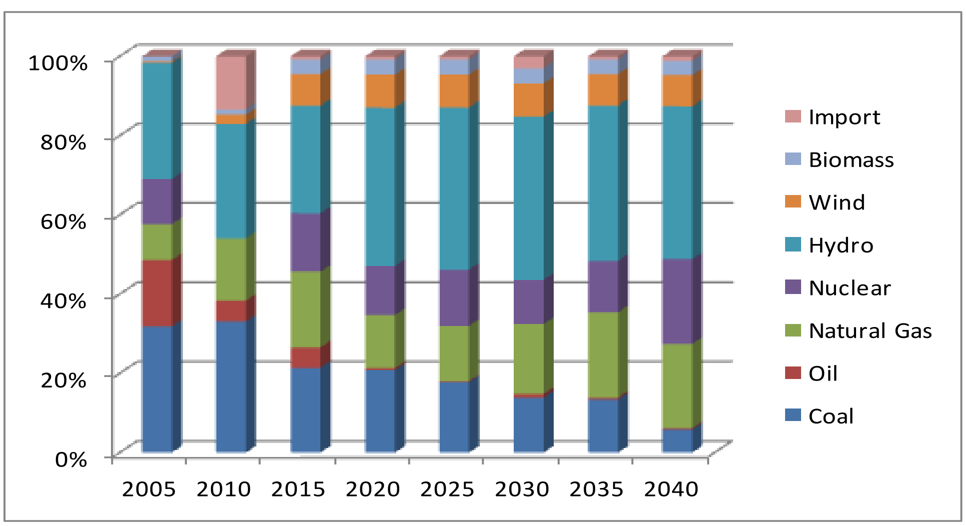


Figure 7
Generation Energy Mix (%GWh)
Base Case Least Cost – Nuclear in NB



The relative energy mix in a resource development plan is of interest, not just because of its influence on emissions, but also from the perspective of diversity of fuel source risk and fuel price volatility. Fuel sources of coal and oil are imported and depend on world markets for cost and availability while wind and hydro are local and natural gas is currently an indigenous resource. Figure 7 provides the relative energy mix for the Base Case Least Cost Plan for the study period and compares them to the actual mix that occurred in 2005 and 2010. Note the large increase in hydro by 2020 as a result of the Muskrat Falls plant and the reduction of coal and oil generation from 49% in 2005 to only 6% by 2040. Also note the amount of imports is small in all years except 2010 when large purchases occurred because of the Point Lepreau outage and low natural gas prices that made ISO-NE imports economic relative to regional oil fired generation.

Additionally, with the region's current natural gas pipeline infrastructure, it will be important to ensure that the development of natural gas units across the region does not outstrip the capacity of the pipeline facilities to deliver a reliable, secure fuel supply to existing and proposed new gas fired generation. Collaborative planning would be required by the utilities if new gas fired generation is brought on line, in order to understand the risk of generation loss to the region that could result from the interruption of fuel supply from the natural gas transmission pipelines.

Sensitivity Analysis Results

NPV sensitivity results for the High Gas Price Case scenario, the Low Load Growth Scenario and the Limited Transmission Expansion scenario are provided in Figure 8. Note that the Combined Regional System includes expanded transmission for the NB-NS and NB-PEI interconnections in the High Gas and Low Load sensitivities but not in the Limited Transmission sensitivity.

Figure 8
Sensitivity Analysis NPV Results
($Millions)

Plans	Standalone Provincial Systems with Existing Transmission Interties	Combined Regional System	Differences
High Gas Prices	$24,228	$23,199	$1,029
Low Load	$17,730	$17,146	$583
Ltd Transmission	$22,395	$21,608	$787

Comparison of these sensitivity results with the Base Case results in the previous section provides several findings of interest as follows:

- The higher gas price in the High Natural Gas Price scenario makes the nuclear plan even more economic than the Base Case Scenario and the regional plan has a NPV benefit of $1029 million compared to the High Gas stand-alone provincial plans. The stand-alone plan for NL is unchanged from the Base Case while the plans for NB, NS and PEI add wind and tidal rather than combustion turbines. Other than installation of 100 MW of wind in each of NS in 2035 and NL in 2039, this High Gas Scenario has the same combined regional resource expansion plan as the Base Case. But even with this additional wind the regional CO_2 emissions are higher by about 1.5 Mte prior to 2030 before reducing gradually from 0.8 Mte higher in 2030 to 0.4 Mte lower by 2040. This is caused mainly by increased use of coal in NB and NS which is more economic than the higher priced natural gas.

- In the Low Load Scenario the least cost plan is still the nuclear expansion but with the combined regional resource NPV benefits reduced to $583 million. The 100 MW of wind in NL that appears in both the High Gas Price case and the Limited Transmission case is not included in the Low Load case. As expected CO_2 emissions in this Low Load scenario are lower in all years by about 2 Mte.

- The Limited Transmission sensitivity reduces transfer capabilities from the Base Case and increases the NPV cost of supply resources by $92 million compared to the combined regional system Base Case. The expansion plan is the same as the High Gas Price plan except that the 100 MW of wind in NL slips its in service from 2039 to 2040. The wind in NS and NL occurs because the limited interconnection reduces the opportunity for economy transfers from NB to NS so it is needed to enable NS to operate within its CO_2 cap.

This result for the Limited Transmission is insightful. As was discussed in the Base Case Results section, preliminary estimates have determined that the cost of the two transmission expansions between NB-PEI and NB-NS is estimated at $565 million in 2015. With a Base Case resource benefit of $879 million the transmission expansion can be paid for and still provide $314 million of benefit for regional ratepayers. However, the Limited Transmission Sensitivity, as modeled, provides $787 million of net present benefit. These preliminary estimates require further analysis and would need to be confirmed through a comprehensive transmission study.

While this particular Sensitivity assumed no expansion of the existing transmission interties, the available transfer capacity of the NB to NS interface has diminished in recent years and it would be reasonable to expect that this decay will only continue over time with local load growth leaving negligible capacity available for firm or economy energy transactions. Accordingly, the benefit of the Limited Transmission Sensitivity is somewhat inflated as some level of transmission expenditures will be necessary to maintain the present transfer capacity into the future. Regardless, the resource benefit determined in this study is only one component of total benefit of transmission and the other components need to be analysed and understood prior to any commitment to expand the interconnections. In short, more detailed transmission work is required and it must be integrated with additional resource analysis in order to determine an optimum expansion for the region. However, it is apparent that a reduced amount of transmission expansion expenditure, from that assumed in the base case, can provide necessary transmission transfer capacity for energy resource optimization. Additional drivers like system reliability, inter-system balancing, reserve sharing and others could combine to require tie line capacity expansions similar to those initially assumed.

A supplemental analysis regarding the potential impact of a tidal energy development opportunity was also undertaken. This analysis determined that tidal energy development would displace CO_2, which would be positive in helping enable Nova Scotia to operate within its CO_2 cap. Large scale deployment of tidal generation would be selected if it was cost-competitive with other clean and renewable sources.

Conclusions

Combined regional planning provides an opportunity to achieve NPV savings in the range of $314 to $787 million dependent on the cost and achievable transfer capacity benefit of transmission expansion to the NB-NS and NB-PEI interconnections.

Observations arising from this study for policy consideration or for further work are as follows:

- There are few significant resource decisions to be taken in the coming decade given that many key decisions for that planning window have been already made (not all on a regional basis) before or during the AEG process.

- This resource modeling study shows increased use of natural gas for electricity generation in all scenarios examined. Development of a long-term regional plan focussed on security of natural gas supply and pipeline infrastructure needs would help ensure that the region could enjoy the forecasted cost and the air emission benefits of natural gas generation.

- Follow up to the AEG work is required for further transmission analysis. A finding of this resource modeling study is that additional transmission analysis is required by the utilities in order to determine an optimal transmission intertie expansion within the region. Transmission transfer capacity within the region promotes the sharing of renewable energy resources and is an important enabler of regional cooperation. There are significant transmission expansion decisions to be made in the near term.

- Hydroelectric generation grows to approximately 45% of the region's electricity supply by 2040. Hydro provides renewable energy but, equally important, it also provides valuable regulation and load following capacity which is a critical enabler of wind and tidal generation. Efforts to promote and protect hydro generating resources are important to allow the progress of renewables in the region.

- Further work is needed to determine how much variable generation can be integrated into the regional resource mix. The *Strategist®* simulation program, like most computer simulations of its type, is not capable of a full representation (sub-hour) of the intermittent nature of wind generation. This additional work could focus on the continued availability of existing hydro, the introduction of additional fast acting generation resources to provide for load following, or other integration options like storage, load shifting, and regional dispatch.

- While some of the resource development options identified in this study are triggered to serve load or respond to capacity retirements, compliance with environmental regulations is an equally important driver. Under the Base Plan, the region would see CO_2 emissions reduced from 15 Mte in 2010 to just under 10 Mte in 2030.

- A critical component of the follow up analysis is a determination of how costs and benefits of transmission expansion and resource development should be shared. This resource modeling study did not address this issue and the results shown are totals for the region as a whole.

Atlantic Energy Gateway Transmission Modeling Study Report

A Study of Transmission Upgrade Options

For

Atlantic Canadian Utilities

March 30, 2012

Table of Contents

AEG Transmission Planning Committee

Organization	Member
New Brunswick System Operator	Alden Briggs Scott Brown
New Brunswick Power Transmission Corporation	Randy MacDonald
Maritime Electric Company Limited	John Cunniffe
Nova Scotia Power Incorporated	Tim Leopold
Newfoundland & Labrador Hydro	Peter Thomas
Government of Nova Scotia	Scott McCoombs

Atlantic Energy Gateway Transmission Modeling Study Report

A Study of Transmission Upgrade Options for Atlantic Canadian Utilities

1. Executive Summary

The Atlantic Energy Gateway (AEG) project is a regional initiative of the federal government, the Atlantic provincial governments, electric utilities of Atlantic Canada and the system operators in New Brunswick and Nova Scotia. The objective of the AEG project is to contribute to the development of Atlantic Canada's clean energy resources by identifying the opportunities and assisting in evaluating the advantages of the region’s substantial and diversified renewable energy potential for wind, tidal, solar, biomass/biofuels, geothermal and hydro.

At the heart of the AEG project is a resource assessment of the Atlantic Canada integrated regional power supply systems through the development of a representative model of the electricity system. That model was used to evaluate the current operation of the system as well as develop scenarios that integrate increasing amounts of renewable and non-emitting energy sources for domestic and export loads.

A tighter integration of the Atlantic Canada electrical system will lead to increased opportunities for inter-provincial energy trade. These opportunities are enhanced by implementing a number of key transmission upgrade options within and between provinces, not just facilities at the borders. Adequate transmission capacity is a key element to generation expansion. Lack of transmission capacity leads to congestion and results in sub-optimal generation dispatch. This results in increased electricity production costs through curtailment of low cost generation and dispatch of more costly alternatives. The addition of transmission capacity will reduce marginal electricity costs across the region.

Various potentially desirable transmission upgrade options were identified by the Transmission Planning Committee. Studies performed using the integrated resource model, under the direction of the AEG Resource Development Modeling group, identified the key interfaces as those between New Brunswick and Nova Scotia, and New Brunswick and Prince Edward Island. These interfaces have been previously studied at a high level to determine their approximate transfer capabilities and the costs to upgrade transmission facilities into this area. This information was provided to the AEG Resource Development Modeling group.

As the resource development plan becomes known and the Atlantic Canada electricity system evolves, more comprehensive transmission studies will be required to assess the impact and define the transmission upgrades necessary to implement the plan.

2. Background

The objective of the Atlantic Energy Gateway (AEG) project is to contribute to the development of Atlantic Canada's clean energy resources by identifying the opportunities, and assisting in evaluating the advantages of the region's substantial and diversified renewable energy potential for wind, tidal, solar, biomass/biofuels, geothermal and hydro.

The AEG project is a collaboration of the four Atlantic Canada provincial energy departments, electric utilities representing each Atlantic Canada province, Atlantic Canada Opportunities Agency and Natural Resources Canada. The work includes planning for generation, transmission, and system operation, as well as electricity markets, supply chain development, research and development and regulatory improvements. The AEG project is an initiative sponsored by the government of Canada to encourage the development of additional clean and renewable energy supplies in Atlantic Canada.

A major component of the AEG work plan is the undertaking of a series of studies designed to provide a plan for the future development of the electrical system. This plan is widely known as an Integrated Resource Plan (IRP). The IRP is a resource assessment of the Atlantic Canada integrated regional power supply systems through the development of a representative model of the electricity system. The model is used to evaluate the current operation of the system as well as develop scenarios that integrate increasing amounts of generation, including renewable and non-emitting energy sources, for supply to domestic and export loads.

A tighter integration of the Atlantic Canada electrical system will lead to increased opportunities for inter-provincial energy trade. These opportunities may be enhanced by implementing a number of key transmission upgrade options within and between provinces. Adequate transmission capacity is a key element to generation expansion.

The purpose of the Transmission Modeling Study, under the direction of the Transmission Planning Committee, is to quantify the increased inter-provincial capacity that would be achieved by a number of key transmission upgrade options within Atlantic Canada. The study also provides estimates of the cost of each of the options.

The results of the study are anticipated to provide information that can be used by Atlantic Canadian governments and utilities in developing and executing energy related policies that will be based on region-wide analyses. The study will develop a greater understanding of the electricity system costs and benefits to guide the policy decision making process with the best information available.

For the purposes of the IRP, Phase I of the Lower Churchill Project is deemed to be in the base case. This consists of the Muskrat Falls generation facility, the Labrador-Island Transmission Link and the Maritime Transmission Link (Figure 1). This project delivers 500 MW via the Maritime Transmission Link to Cape Breton.

As a result of the Lower Churchill Project being in the base case, the focus of the Transmission Modeling Study is on the transmission capability in and between the Maritime Provinces. The Maritime Provinces transmission system must be capable of accommodating the 500 MW of injection into Cape Breton as well as accommodating evolving generation and load patterns in the Maritimes. The Transmission Modeling Study did not include analysis of any of the transmission which forms part of the Muskrat Falls, Labrador-Island Transmission Link or the Maritime Transmission Link.

Figure 1: Phase One – Muskrat Falls, Labrador-Island Link and Maritime Link

3. Transmission Study Approach

A Transmission Planning Committee representing governments and utilities of Atlantic Canadian provinces was formed to coordinate the efforts of the AEG transmission study. This Transmission Planning Committee was chaired by the New Brunswick System Operator (NBSO).

In Phase I of the transmission study, various potentially desirable transmission upgrade options were identified by the Transmission Planning Committee. This list is provided in Appendix 1. These transmission upgrade options were to be studied at a high level to determine their approximate transfer capabilities and associated cost. These transfer capabilities and costs were then to feed into the associated IRP study.

In Phase II of the transmission study, comprehensive transmission studies were to be preformed on the viable transmission options flowing from the IRP.

The AEG Resource Development Modeling group contracted with Ventyx to do the resource study. Ventyx's task was to develop a system model to be used in a series of production cost simulations using their planning software (Strategist). These studies were completed under the direction of the AEG Resource Development Modeling group.

Initially, Ventyx studied two scenarios. The first scenario, the 'Expanded Transmission Capability' option, assumed that transmission capacity was upgraded to achieve higher interface capabilities as follows:

- NB ← NS = 800 MW
- NB → NS = 800 MW
- NB ← PEI = 350 MW
- NB → PEI = 350 MW
-

The higher interface capabilities between NB, NS and PEI do not exist today. To achieve these levels, additional transmission infrastructure is required. These Transmission Upgrades are discussed in Section 5.

The second scenario, the 'Limited Transmission Capability' option, assumed that transmission capacity is as it exists today. Further detail of existing transmission interface capacity is included in section 4 and in Appendix 2.

The production modeling process identified the key interfaces as those between New Brunswick and Nova Scotia and New Brunswick and Prince Edward Island. These interfaces have been previously studied at a high level to determine their approximate transfer capabilities and associated cost. This information was provided to the AEG Resource Development Modeling group. At this time, it is unknown if there is a requirement to study any of the other transmission projects identified in Appendix 1.

4. Existing Transmission Capacity

The Total Transfer Capability (TTC) of an interface is a best engineering estimate of the total amount of electric power, measured in MW, which can be transferred over an interface in a reliable manner for a given timeframe. The TTC of an interface is determined by performing power flow and stability studies under seasonal system conditions. Note that the TTC and is a combination of firm and non-firm transactions. Further details of the methodology for calculating transmission capacity can be seen in Attachment C of the NBSO Open Access Transmission Tariff.

The existing TTC between regions as currently posted on the NBSO OASIS are shown on the map below (Figure 2). Further discussion is attached as Appendix 2 titled "Summary of Existing Firm and Non-Firm Transmission Capacity of New Brunswick Interfaces with Nova Scotia and PEI". Note that there are many factors to be considered when determining the capability of the transmission system.

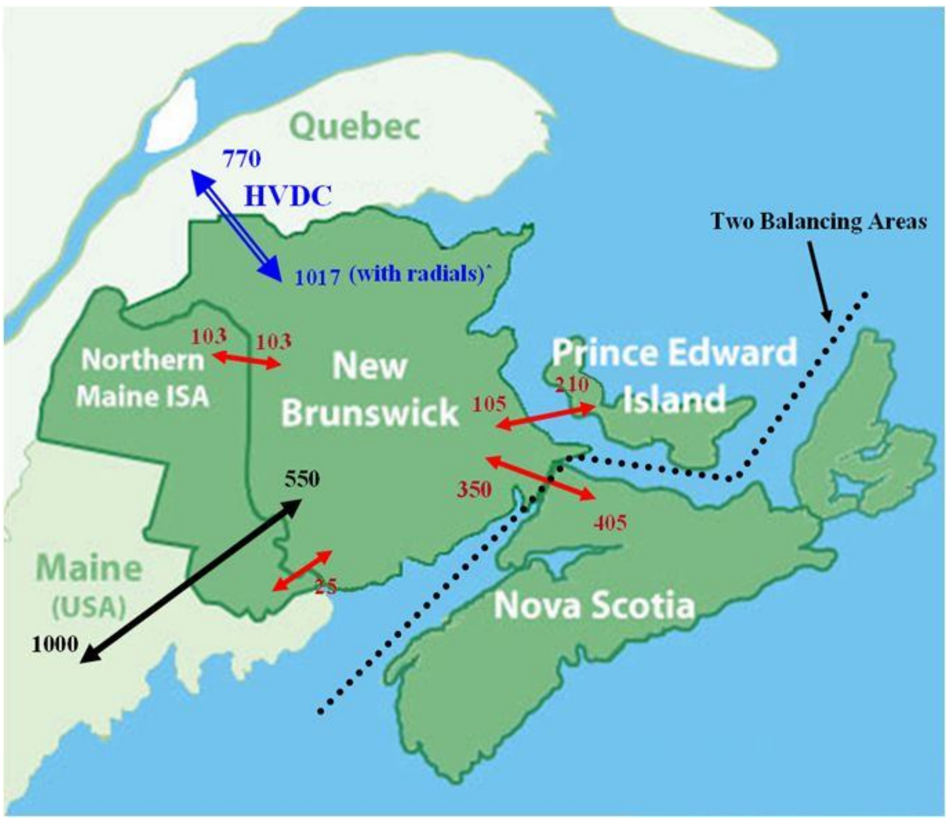


Figure 2: Existing Interface Total Transmission Capabilities (MW)

Note: The NB→NS flow is limited to 300 MW under normal conditions. This is due to an NS System Operating Limit put in place to avoid unacceptable amounts of under frequency load shedding in NS for loss of the interface.

5. Transmission Upgrades

The production modeling process identified the key interfaces as being those between:

1. New Brunswick and Nova Scotia, and
2. New Brunswick and Prince Edward Island

These interfaces have been previously studied at a high level to determine their approximate transfer capabilities and associated cost. A summary of the findings from these previous studies follow.

- <u>The New Brunswick-Nova Scotia Interface</u>

The NB-NS interface was studied by NB Power and NS Power in 2010. The study was prompted by the desire to investigate the options to increase the total transfer capabilities between NB and NS. The study team examined the options necessary to expand the 345 kV transmission system between the provinces. This study included both analysis of transmission capacity and capital cost for proposed infrastructure additions. The transmission reinforcements recommended in this report provide a potential solution to increasing the transfer capability to at least 800 MW in both directions between New Brunswick and Nova Scotia.

The recommended reinforcements of the existing system required the following:

- a second 345 kV transmission line from Onslow to Salisbury with a tap into Memramcook
- a second 345 kV transmission line from Salisbury to Coleson Cove
- a new 138 kV line from Springhill to Onslow
- additional voltage control at Norton, Salisbury and Memramcook

The estimated total cost of the transmission infrastructure additions is $411 million.

- <u>The New Brunswick-Prince Edward Island Interface</u>

The NB-PEI interface has been the subject of previous study. The study concluded that the addition of a third 138 kV cable connecting the two provinces would provide a total of at least 350 MW interface capability in both directions. The new cable would parallel the existing 138 kV cables and terminate at or near the existing submarine cable terminations in New Brunswick and PEI. The estimated cost of the new interconnection facilities is approximately $77 million.

In addition, a third line between the Memramcook and Murray Corner substations is required to fulfill the potential of 350 MW of load flow in both directions on the NB-PEI interface. The cost of this line is approximately $28 million. Further study is required to refine the route and specifics of this transmission line.

Table 1: Transmission Analysis Summary

Transmission Upgrade Option	Terminal	Terminal	Interface Capability (MW)		Cost[2] $ x million
			NS→NB	NB→NS	
345 kV Onslow/Coleson Cove	Onslow, NS	Coleson Cove, NB	800	800	$454
345 kV Onslow/Salisbury	Onslow, NS	Salisbury, NB	750	tbd	$224
345 kV Onslow/Memramcook	Onslow, NS	Memramcook, NB	500+[1]	tbd	$176

(1) The export from NB to PEI is to be added to this Transfer capability.
(2) 2010 estimate escalated to year 2015 at 2% per year.

Transmission Upgrade Option	Terminal	Terminal	Interface Capability (MW)		Cost[3] $ x million
			PEI→NB	NB→PEI	
138 kV PEI/Murray Corner	Bedeque, PEI	Murray Corner, NB	350	350	$111

(3) 2012 estimate escalated to year 2015 at 2% per year.

6. Discussion of Results

The AEG Transmission Planning Committee initially had a broad focus on potentially beneficial transmission upgrades. The production modeling process quickly identified the key interfaces as being those between New Brunswick and Nova Scotia and New Brunswick and Prince Edward Island. These interfaces had been previously studied at a high level to determine their approximate transfer capabilities and associated cost.

Findings identified in this report are preliminary. Existing studies were used where available to determine cost and identify potential operational issues. The extent of transmission studies to date is not sufficient to commit to installation and operation of transmission infrastructure required to increase tie capacity at various interfaces.

Appendix 3 identifies studies that are required to access the impact and define the requirements necessary to enhance the transmission capabilities of NB interfaces with NS and PEI that may be desirable for the horizon years 2020 and 2040. This document does not include details for additional system impact studies required for the transmission grids within Nova Scotia, PEI, and Newfoundland and Labrador. They too will need studies similar to those outlined in Appendix 3.

AEG Transmission Modeling Study
Appendix 1

Table 1: Preliminary List of AEG Regional Transmission Upgrade Options

#	Transmission Upgrade Option	Terminal (From)	Terminal (To)
1a	345 kV Onslow/Coleson Cove	Onslow, NS	Coleson Cove, NB
1b	345 kV Onslow/Salisbury	Onslow, NS	Salisbury, NB
1c	345 kV Onslow/Memramcook	Onslow, NS	Memramcook, NB
2a	138 kV PEI/Memramcook	PEI	Memramcook, NB
2b	138 kV PEI/Murray Corner	PEI	Murray Corner, NB
3	138 kV PEI/NS	PEI	NS
4	HVDC Bottom Brook/Lingan	Bottom Brook,NL	Near Lingan, NS
5	HVDC NL/Salisbury	NL	Salisbury, NB
6	Options 1a & 2a	n/a	n/a
7	Options 1a & 2a & 4	n/a	n/a
8	345 kV Lepreau/Orrington	Lepreau, NB	Orrington, Maine
9	HVDC NB/HQ	NB	HQ
10	HVDC Lepreau/NE	Lepreau, NB	tbd
11	HVDC Lepreau/NE	Lepreau, NB	tbd
12	Options 7 & 8	n/a	n/a
13	Options 7 & 9	n/a	n/a
14	Options 7 & 8 & 9	n/a	n/a
15	345 kV Digby/Lepreau	Digby, NS	Coleson Cove, NB
16	Upgrade NB & MPS Interface	tbd	tbd

AEG Transmission Modeling Study
Appendix 2

Summary of Existing Firm and Non-Firm Transmission Capacity of New Brunswick Interfaces With Nova Scotia and PEI For AEG Resource Group Modelling

1.0 Summary

The existing 2011/12 Firm and Non-Firm transmission capacities available on the New Brunswick/Nova Scotia interface and the New Brunswick/PEI interface are shown in the following table.

2011/12								
	NB / NS Interface				NB / PEI Interface			
	NB → NS		NS → NB		NB → PEI		PEI → NB	
	Firm	Non-Firm	Firm	Non-Firm	Firm	Non-Firm	Firm	Non-Firm
Winter	0	300	178	350	80	210	105	105
Summer	20	300	178	350	80	210	105	105

Winter season months are November to March inclusive. Summer season months are April to October inclusive.

For AEG Resource modeling, the 2011/12 Firm and Non-Firm transmission numbers represent the Limited Transmission case in years 2020 through 2040 with the following assumptions:

- Existing reserve sharing agreements are maintained.
- Existing firm transmission reservations are renewed.
- Existing transmission numbers do not reflect future resource and load changes affecting transmission flows in the south eastern area of NB, and these changes are unknown at this time.

2.0 References

[1] *Total Transfer Capability Report of the NSPI and MECL Interfaces for Winter 2011-12 Part 1*. July 29, 2011

[2] *Total Transfer Capability Report of the NSPI and MECL Interfaces for Winter 2011-12 Part 2*. October 12, 2011

3.0 Background - Summary of 2011/12 TTC and TRM Values

2011/12								
	NB / NS Interface				NB / PEI Interface			
	NB → NS[1]		NS → NB[2]		NB → PEI[3]		PEI → NB[4]	
	TTC	TRM	TTC	TRM	TTC	TRM	TTC	TRM
Winter	405	405	350	172	210	130	105	0
Summer	405	385	350	172	210	130	105	0

[1] The NB → NS TTC value is comprised of the following two components:

- 300 MW of this TTC value is due to an NS System Operating Limit (SOL) under normal system conditions in place to avoid unacceptable amounts of under frequency load shedding in NS for loss of the NSPI interface.
- 105 MW of this TTC value allows for NS access its portion of the Maritime reserve requirement under emergency conditions.

The NB → NS TRM values account for variances in generation dispatch. Under high flows from southwest NB into southeast NB line 1149 can become overloaded for the loss of line 3004. A portion (105 MW) of the total TRM for this interface for exports from NB to NS must be set aside to allow NS access to its share of the Maritime reserve requirement. This TRM value is also related to the transfer capability constraints for simultaneous exports from NB to NS and PEI, and the current 80 MW of long-term firm reservations from NB to PEI.

[2] The NS → NB TTC value is limited by an SOL in NS. This SOL restricts imports to NB from NS in order to avoid rejecting more than two Lingan units to remain tied to the NB transmission system for the loss of the interconnecting 345 kV line 3025/8001.

The NS → NB TRM value allows for NB access to its 172 MW share of the Maritime reserve requirement.

[3] This NB → PEI TTC value is limited by the 8 hour thermal limit (105 MW at a 0.9 pf) of each 138 kV undersea cable between the Murray Corner (NB) and Bedeque (PEI) terminals. There is a Cable Overload Scheme in PEI that will shed load in PEI for the loss of one cable to protect the remaining in-service cable.

This NB → PEI TRM value accounts for variances in generation dispatch. Under high flows from southwest NB into southeast NB line 1149 can become overloaded for the loss of line 3004. This TRM value is related to the transfer capability constraints for simultaneous exports from NB to NS and PEI. Currently there are long-term firm reservations totalling 80 MW from NB to PEI across the MECL interface. These long-term firm commitments exceed the firm limit when the NB system load is slightly above 2600 MW. The possible options for meeting these long-term firm commitments include:

- The appropriate dispatch of generation.
- Implementing a temporary operational mitigation measure to monitor loading on line 1149 and take operator action as needed.

[4] This PEI → NB TTC value is limited by the eight hour thermal limit (117 MVA) of one undersea 138 kV cable between NB and PEI for the loss of the other 138 kV undersea cable. A power factor of 0.90 has been factored into the TTC limit.

There is no TRM required.

4.0 Background - Summary of 2011/12 Firm and and Non-Firm Transmission Capacity

The TTC/TRM values is section 3.0 are converted to Firm and Non-Firm as follows:

- Firm Transmission = TTC – TRM
- Non-Firm Transmission Capacity = TTC – reserve sharing amount

2011/12								
	NB / NS Interface				NB / PEI Interface			
	NB → NS		NS → NB		NB → PEI		PEI → NB	
	Firm	Non-Firm	Firm	Non-Firm	Firm	Non-Firm	Firm	Non-Firm
Winter	0	300	178	350	80	210	105	105
Summer	20	300	178	350	80	210	105	105

AEG Transmission Modeling Study
Appendix 3

Scope of Transmission Studies to Accommodate the Proposed AEG Transfer Levels Via NB Interfaces with its Atlantic Neighbours 2020 to 2040

January 30, 2012

Power System Engineering
New Brunswick System Operator
510-C Brookside Drive
Fredericton, NB Canada
E3A 8V2

Scope of Transmission Studies to Accommodate the Proposed AEG Power Transfer Levels Via NB interfaces with its Atlantic Neighbours 2020 to 2040

1. Background Information

- The Atlantic Energy Gateway (AEG) initiative is an opportunity to promote and facilitate the development of clean and renewable energy sources in Atlantic Canada. The initiative will complement all current and future energy plans and resources being undertaken in the region in the timeframe between 2020 to 2040.

- The AEG Initiative involves work by the four Atlantic Canada energy departments, their provincial utilities and ACOA and Natural Resources Canada. The work includes planning for generation, transmission, and system operation, as well as electricity markets, supply chain development, research and development and regulatory improvements.

- Because of its geographic location New Brunswick is impacted by changes to import, export and wheeling of electrical power directly to and from Nova Scotia, Prince Edward Island, Quebec and New England, and indirectly to and from Newfoundland and Labrador.

2. Objectives of this Document:

1. Give a brief summary of the existing Total Transmission Capabilities (TTC) between NB and its neighbouring systems with focus on NB interface capabilities with NS and PEI.

2. Give a scope of the transmission studies required to assess the impact and define the requirements necessary to enhance the transmission capabilities of NB interfaces with NS and PEI, in light of the preliminary findings of the AEG Resource Modeling and Transmission groups for the horizon years 2020 and 2040.

3. Give an estimate of the man-weeks required to complete the studies.

4. This document does not include details for additional system impact studies required for the transmission grids in Nova Scotia, PEI, and Newfoundland and Labrador.

.

3. Summary of Total Transfer Capability (TTC) Values between NB and Neighbouring Systems

The geographical map of Figure 1 shows NB electrical interfaces with neighbouring systems. The existing 2011/12 export and import TTC values at various NB electrical interfaces are shown in Figures 2 and 3 respectively.

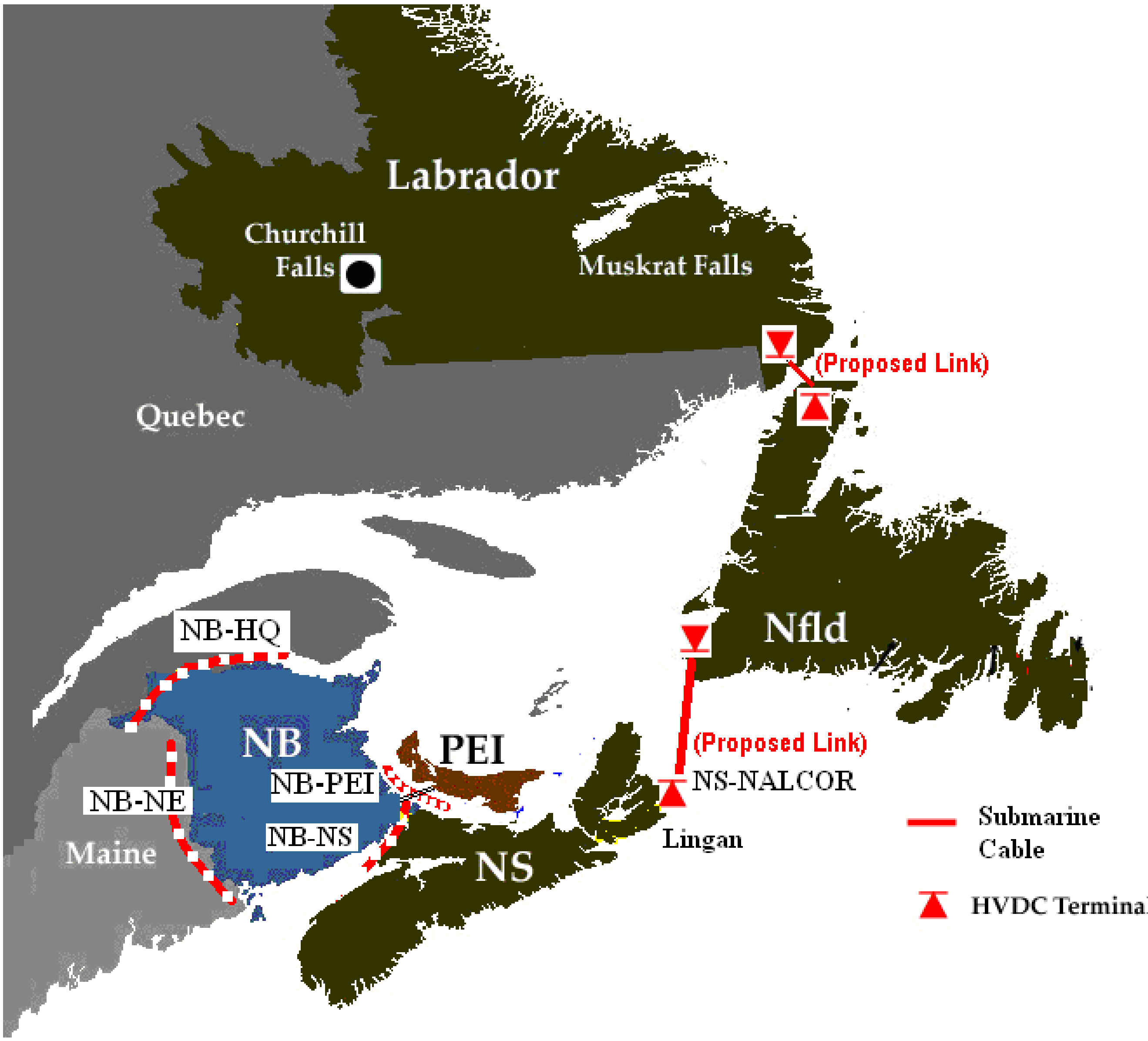


Figure 1: New Brunswick Electrical Interfaces with Neighbouring Systems

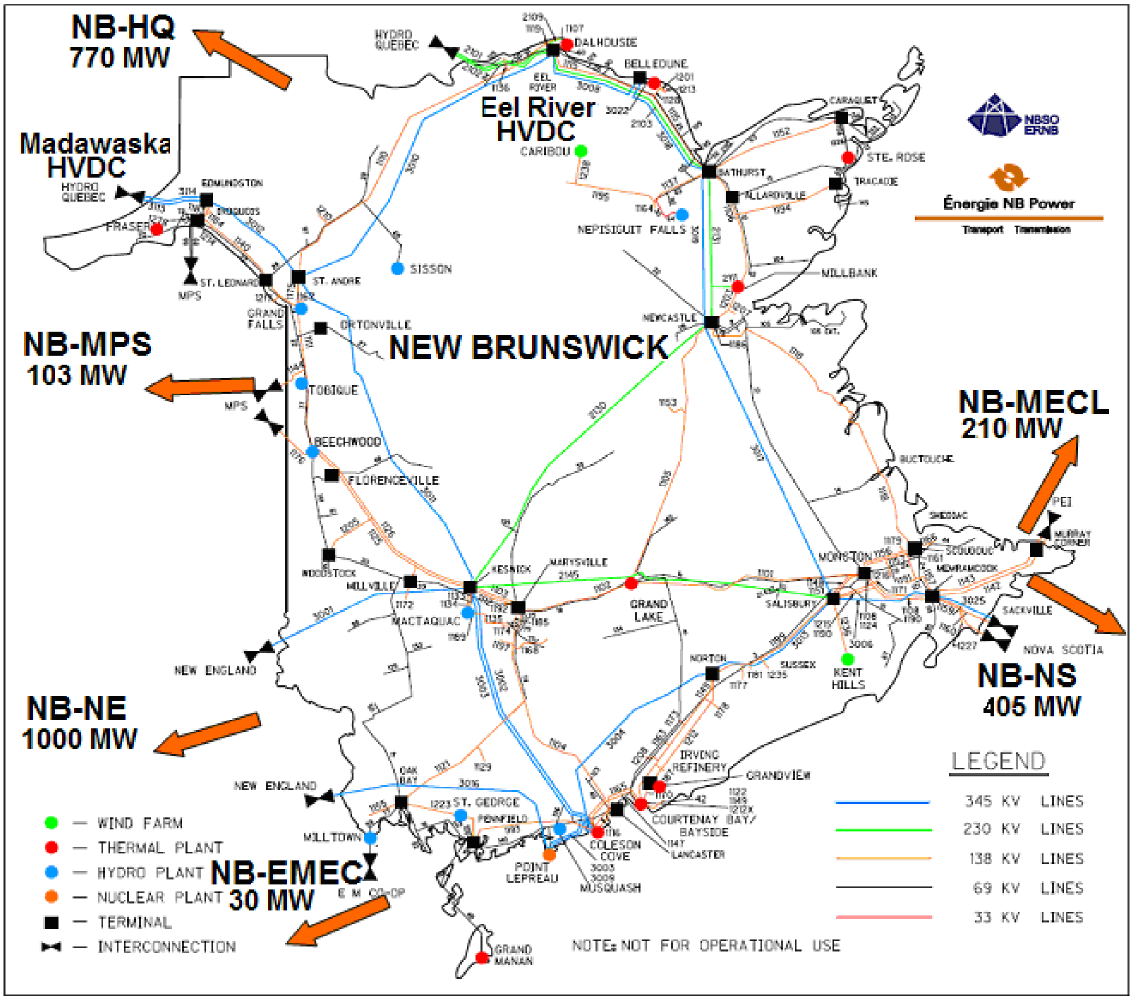


Figure 2: NB Transmission Map Showing Maximum Export TTC Values as of 2011/12

Note: The NB→NS flow is limited to 300 MW under normal conditions. This is due to an NS System Operating Limit put in place to avoid unacceptable amounts of under frequency load shedding in NS for loss of the interface.

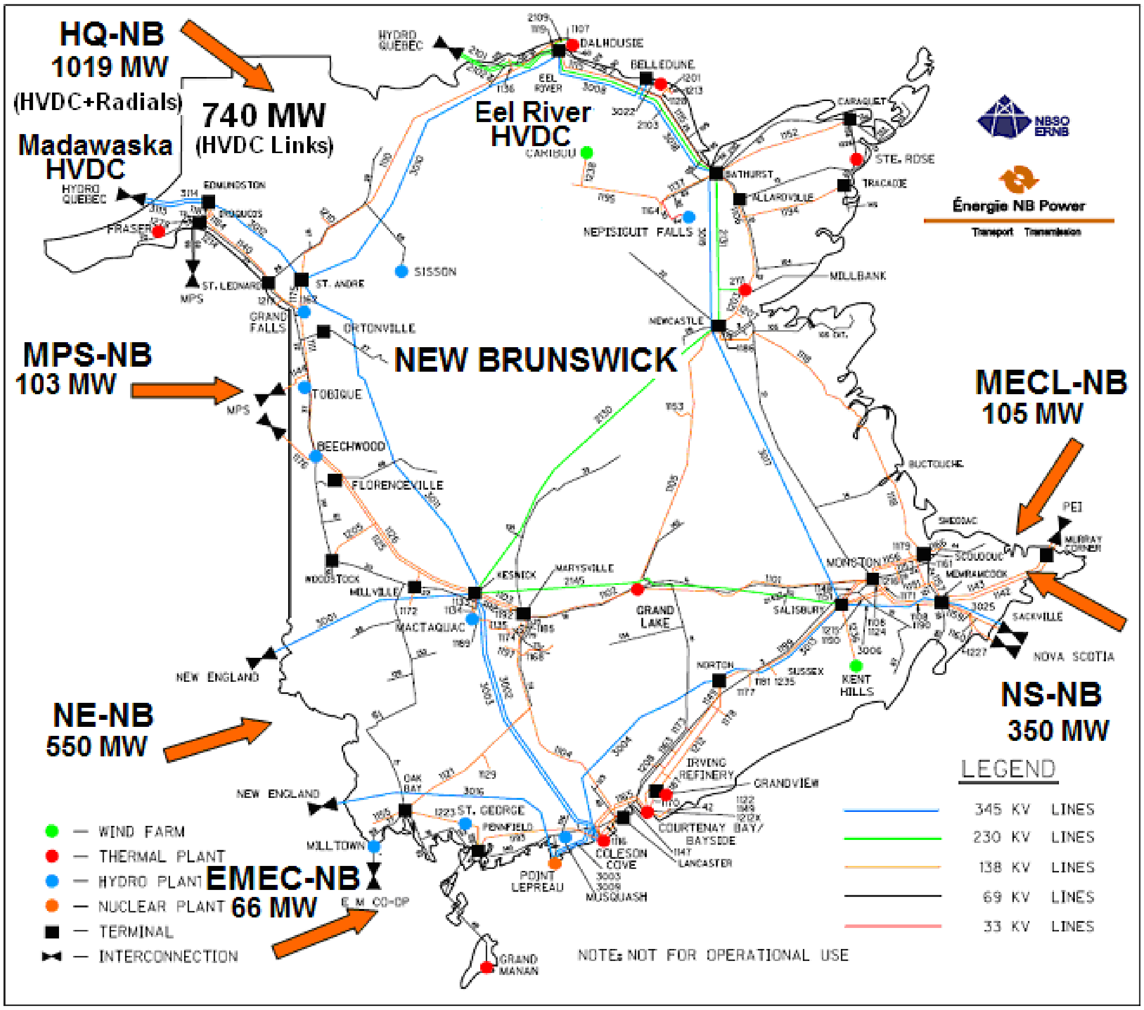


Figure 3: NB Transmission Map Showing Maximum Import TTC Values as of 2011/12

4. Firm and Non-Firm Transfer Capability of NB Interfaces with NS and PEI

The present Firm and Non-Firm transmission capacities available on the New Brunswick/Nova Scotia interface and the New Brunswick/PEI interface are shown in Table 1. For AEG Resource modeling, the 2011/12 Firm and Non-Firm transmission numbers represent the Limited Transmission case in years 2020 through 2040 with the following assumptions:

- Existing reserve sharing agreements are maintained.
- Existing firm transmission reservations are renewed.
- Existing transmission numbers do not reflect future resource and load changes affecting transmission flows in the southeastern area of NB, and these changes are unknown at this time.

Table 1: Firm and Non-Firm Capability of NB Interfaces with NS and PEI -2011/12

2011/12								
	NB / NS Interface				NB / PEI Interface			
	NB → NS		NS → NB		NB → PEI		PEI → NB	
	Firm	Non-Firm	Firm	Non-Firm	Firm	Non-Firm	Firm	Non-Firm
Winter	0	300	178	350	80	210	105	105
Summer	20	300	178	350	80	210	105	105

5. Transmission Studies Required to Enhance the Capability of NB Interfaces with NS and PEI-2020 to 2040

As indicated in Table 1, the firm transfer capacity between NB and its Atlantic neighbours is almost zero. Although the tables display some non-firm numbers, the number of hours that the grid is capable of serving these non-firm quantities is expected to shrink in the future as load grows, particularly in south eastern New Brunswick. Therefore in order to meet the objectives of the AEG initiative and effectively utilize the electrical energy resources in Atlantic Canada, enhancing NB interfaces with NS and PEI may be required.

Building on previous preliminary studies between NB Power and Nova Scotia Power, this document gives the scope of additional studies required to assess the impact of three transmission development scenarios:

<u>Scenario A</u>: This scenario, shown in Figure 4, involves building 345 kV transmission lines parallel to existing lines from Coleson Cove-Salisbury-Memramcook in NB to Onslow, NS, with the objective of achieving firm bidirectional transfer capacity between NB and NS of 800 MW. This development scenario will include the necessary terminations of the new lines, reactive/voltage control facilities, and upgrade/enhancement of the underlying 138 kV systems in NB and NS. Comprehensive study is required to define the requirements to achieve that objective and assess the impact on the interconnected system. Also, study is required to assess the individual and simultaneous TTC values between the NB system and its interfaces with NS and PEI.

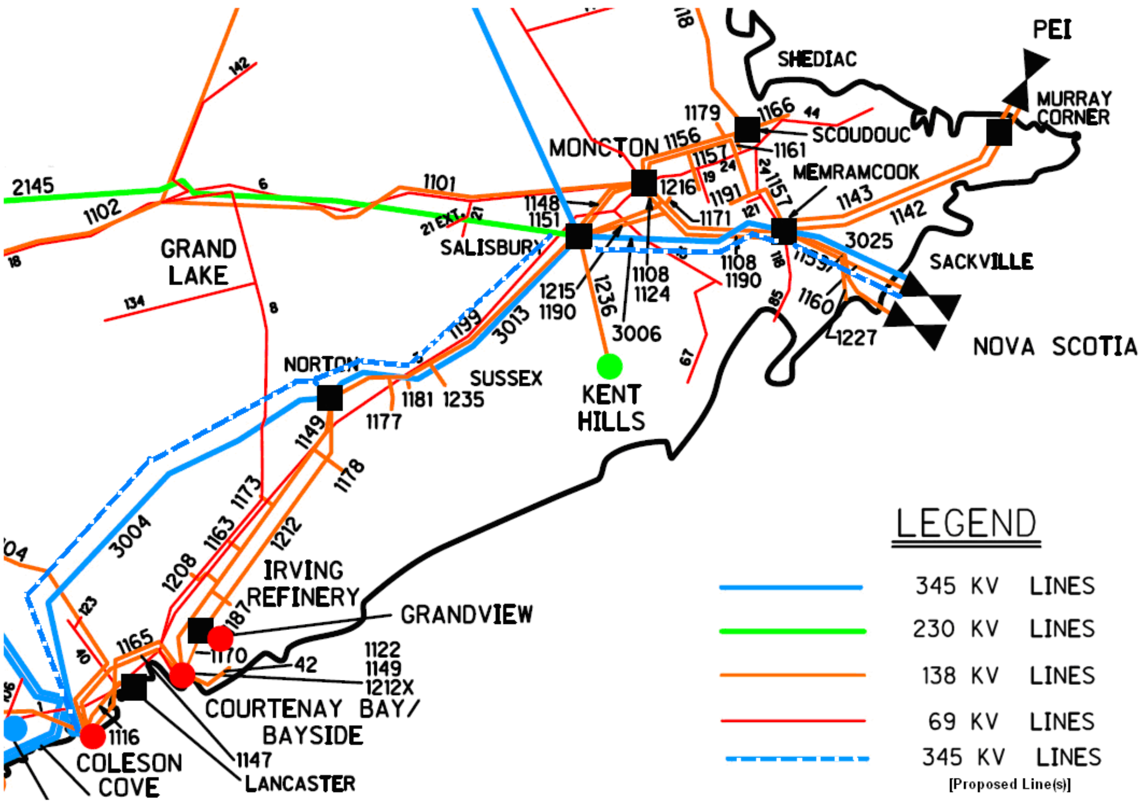


Figure 4: Transmission Development Scenario "A"

Scenario B: This scenario, shown in Figure 5, involves building parallel 345 kV lines only from Salisbury-Memramcook in NB to Onslow, NS. This scenario aims mainly at achieving a TTC value from NS to NB of about 750 MW, based on preliminary studies. Further comprehensive study is required to define the requirements to achieve that objective and assess the impact on the interconnected system. Also study is required to assess the individual and simultaneous TTC values between NB system and NS and PEI interfaces.

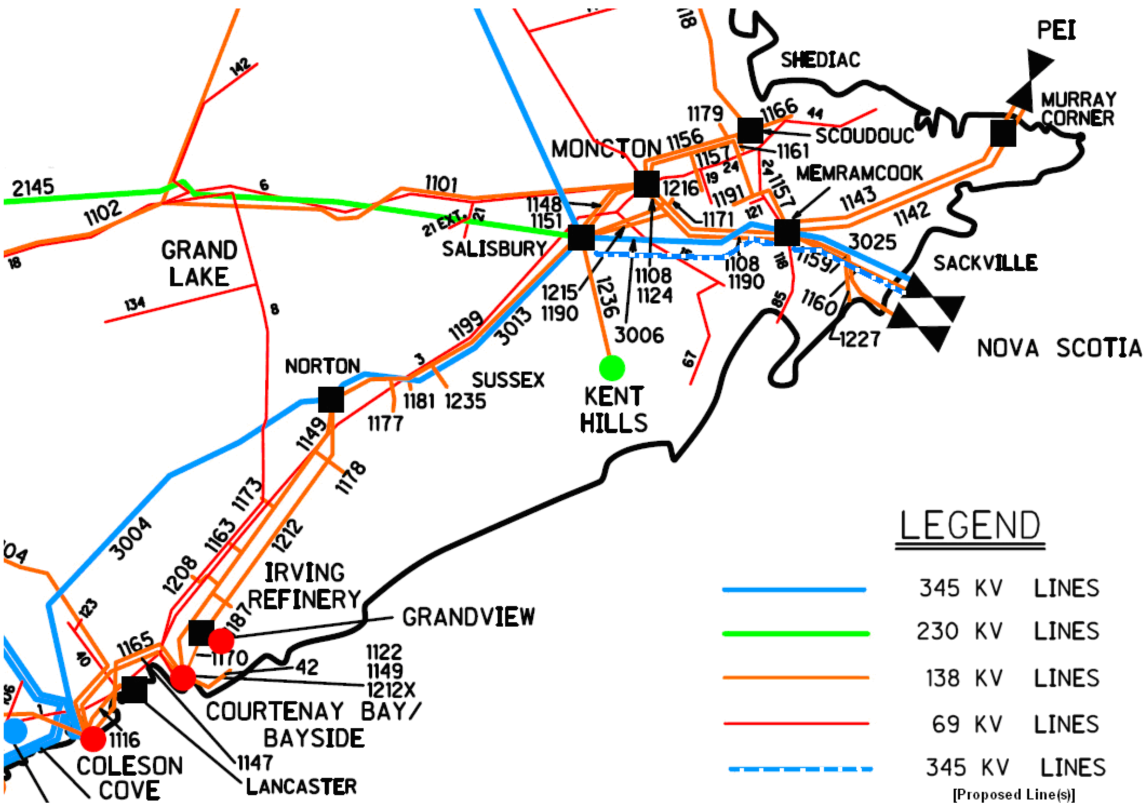


Figure 5: Transmission Development Scenario "B"

<u>Scenario C</u>: This scenario, shown in Figure 6, involves limited development of the 345 kV transmission system between Memramcook, NB and Onslow, NS. This scenario aims mainly at achieving a TTC value from NS to NB of about 500 MW, based on preliminary studies. Further comprehensive study is required to define the requirements to achieve that objective and assess the impact on the interconnected system. Also study is required to assess the individual and simultaneous TTC values between NB system and NS and PEI interfaces.

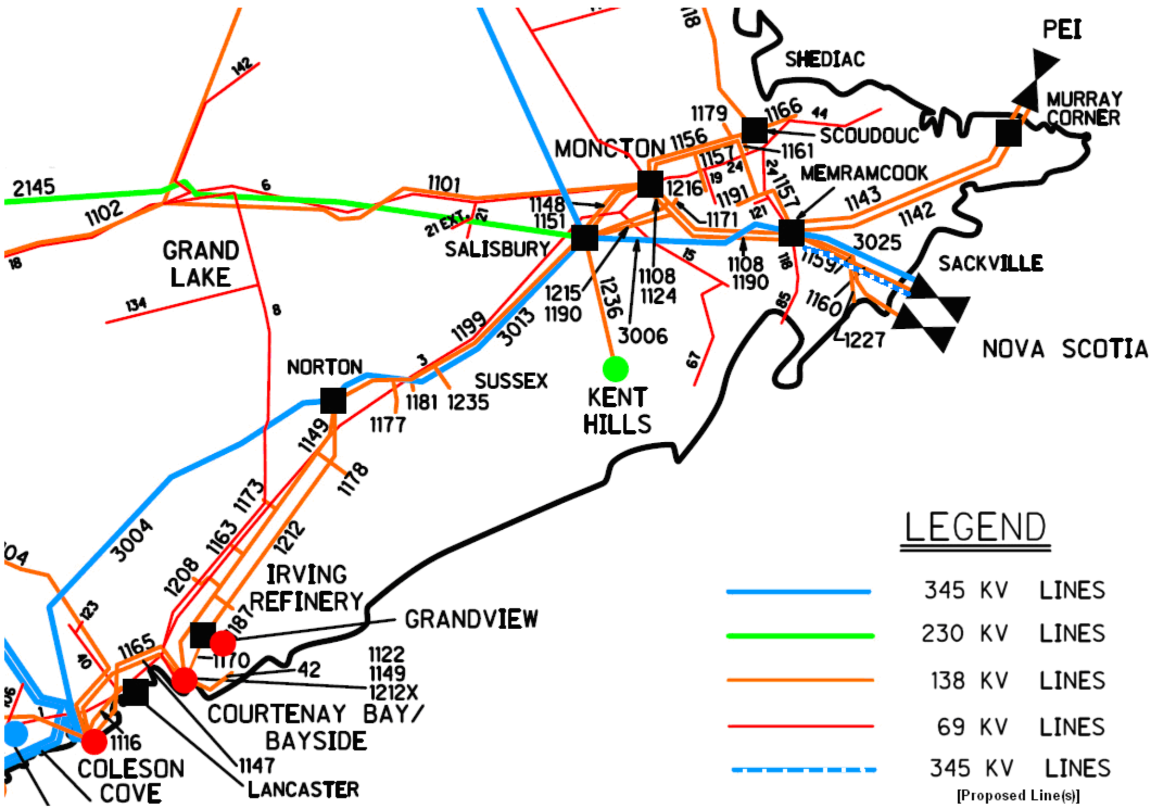


Figure 6: Transmission Development Scenario "C"

6. Study Scope for Transmission Development Scenario 'A" for 2020/2021:

Basic Assumptions**:**

- Study year 2020.
- No under voltage load shedding, no curtailment of firm load or firm transactions for design (normal criteria) contingencies as per NPCC and NERC criteria and standards.
- Size of largest acceptable loss of load in the Maritimes is 250 MW.
- Transmission development under the MPRP in Maine, USA is complete.
- Size of the largest acceptable loss of source in the Maritimes is 740 MW (Equivalent to simultaneous import from both Madawaska and Eel River).
- A third cable between PEI and NB is installed.
- Development of Muskrat Falls project.
- The HVDC interconnection between NFLD and NS has been developed.
- Any other transmission or generation projects in Atlantic Canada and Maine, USA foreseen by 2020.

Base Case Development:

- Load Levels Based on forecasted load in NB and neighbouring systems for year 2020:
    - Winter Peak
    - Summer Peak Load
    - Summer Light Load
- Generation dispatch in NB and the Maritimes in general: Include all committed wind generation or any other potential projects by 2020 as presented in the AEG resource modeling group report.
- A special Winter Peak base case without any wind generation in the Maritimes will be developed.
- Network configuration and assumptions for new transmission facilities will be modeled as in the most recent NPCC Overall Transmission Review. The base cases will be modified to incorporate any additional transmission reinforcements in NB and NS systems, which will be identified in the course of this SIS, for the purpose of accommodation of the TSRs from HQ to NS.
- Import/Export conditions over NB interconnections with, Quebec and New England will be modeled at their Total Transfer Capabilities.

Approach for Developing the Base Cases for Transmission:

- Start from Base Cases of the most recent NPCC Overall Transmission Review.
- Update load, dispatch and network for 2020/2021 as per most recent load forecast.
- Incorporate NB, NS and PEI initial modeling assumptions for their respective systems.
    - NB/NS interface upgrades
    - HVDC bus location to connect Nova Scotia with NALCOR.

- Model other potential transmission assumptions for each of the three transmission development scenarios A, B and C (e.g. 345 kV reinforcement between Coleson Cove, Salisbury, Memramcook and Onslow).
- Model any additional reinforcements required for the underlying 138 kV system and voltage/reactive controls.
- Model equivalent generators to account for potential new sources in the future as documented in by the AEG resource modeling group.

- The tentative matrix of Base Cases for the study year 2020/2021, assuming the transmission scenario "A", is shown in Table 4.

Table 4: Matrix of Base Cases for Transmission Development Scenario A 2020/2021

		Import/ Export (MW)				
		NB-NS	NB-PEI	NB-NE	NB-HQ (HVDC)	NALCOR-NS
Summer Light Load	SL-D1-A	-800	100	1000	500[1]	500
	SL-D2-A	800	100	1000	-740	-320
Summer Light Load (Lepreau off)	SL-D3-A	-800	-200	1000	0	500
	SL-D4-A	800	200	1000	-740	-320
Intermediate Load (Summer Peak)	SP-D1-A	-800	-200	1000	500[1]	500
	SP-D2-A	800	200	1000	-740	-320
Winter Peak Load	WP-D1-A	-800	200	1000[2]	0	500
	WP-D2-A	800	200	1000[2]	-740	-320
Winter Peak Load (Lepreau off)	WP-D3-A	-800	200	0	-350	500
	WP-D4-A	800	200	-500	-740	-320
Winter Peak Load (All wind in Maritimes off)	WP-D5-A	-800	200	-500	0	500
	WP-D6- A	800	200	-500	-740	-320

Notes:

1) To observe the simultaneous export limits to NE and HQ and the 250 MW maximum loss of load limit, the 500 MW export limit to HQ is composed of 250 MW at each of Eel River and Madawaska HVDC links.
2) NB to NE Transfer will be adjusted up to 1000 MW, depending on availability of generation capacities in NB.

Study and Analysis:

- Part I: All Facilities In-Service:
  - Steady State Analysis:
  - Thermal and Voltage/Reactive (V/R) analysis

  - Single Contingency Load Flow Analysis
  - Identify any additional facilities required to support the transfers listed in the matrix of base cases. Modify the base case as necessary.
  - Normal Criteria Transient Stability and Post Contingency Analysis
  - Extreme Contingency Analysis. To test if there is an adverse system impact that may require mitigation measures.
  - Review of Special Protection Systems (SPSs)
  - Short Circuit Analysis. To test if there is a need to upgrade the protection or switching switchgear.
  - Conclusions and Recommendations for Part I
- Part II: Under Single Contingency Outage (n-1) Conditions
  - List of Facilities out-of-service.
  - For each out-of-service facility reconstruct a new base case, taking into consideration the 30 minute dispatch including adjusting the transfers between NB and its neighbouring systems.
  - Reconstruct base case import/export matrix.
  - Steady State Analysis.
  - Thermal and V/R analysis.
  - Single Contingency Load Flow Analysis
  - Normal Criteria Transient Stability and Post Contingency Analysis
  - Extreme Contingency Analysis
  - Review of Special Protection Systems (SPSs)
  - Short Circuit Analysis
  - Conclusions and Recommendations for Part II

Study Scope for Transmission Development Scenario ‘A” for 2040/2041:
Modify the matrix of base cases as per the input from the AEG Resource Group. Repeat the analysis for year 2040/2041 following the same procedure as given in Section 6 for year 2020/2021.

Study Scopes for Transmission Development Scenarios ‘B” and “C” are similar to “A”, but require development of new matrices of base cases, based on input from the AEG Resource Group.

References:

[1] *Summary of Existing Firm and Non-Firm Transmission Capacity of New Brunswick Interfaces with Nova Scotia and PEI for AEG Resource Modeling Group, NBSO, January 18, 2012.*
[2] *Total Transfer Capability Report of the NSPI and MECL Interfaces for Winter 2011-12 Part 1.* July 29, 2011
[3] *Total Transfer Capability Report of the NSPI and MECL Interfaces for Winter 2011-12 Part 2.* October 12, 2011

NBSO Time Estimate for of Completion of the Transmission Study of the Three Proposed Transmission Scenarios for the AEG Initiative:

An estimated person-weeks for completion of the studies is given below.

Task	Estimated Time (Engineer-weeks)
Base Case Set-Up (data collection, load flow, dynamics, automation files, diagrams, etc) for year 2020/2021-Transmission Scenario A	3
Steady State Simulation and Analysis-Scenario A	3
Transient Simulation and Analysis-Scenario A	4
Repeat for year 2040/2041-Scenario A	8
Repeat for Transmission Scenario B 2020/2021 and 2040/2041	15
Repeat for Transmission Scenario C 2020/2021 and 2040/2041	10
Miscellaneous (meetings, resolving of unforeseen issues, etc)	4
Compilation of Report	4
Total Estimated Time	51

AEG Transmission Modeling Study
Appendix 4

Labrador – Island Link and Maritime Link Description

Introduction

Phase One of the Lower Churchill Project includes development of the Muskrat Falls generating facility on the lower Churchill river in Labrador, construction of high voltage ac transmission between Churchill Falls and Muskrat Falls, construction of an HVdc transmission system between Labrador and the Island of Newfoundland, high voltage ac transmission upgrades on the Island and construction of an HVdc transmission system between Newfoundland and Nova Scotia.

Muskrat Falls Generating Station

The Muskrat Falls Generating Station will consist of four 206 MW hydroelectric generator sets for a rated plant capacity of 824 MW. The electric generators will have a 0.90 power factor to provide the necessary reactive power supply to the HVdc converter station located adjacent to the plant. Kaplan turbines will be utilized as the prime mover.

Labrador Transmission Additions

The Muskrat Falls generator step-up transformers will increase the voltage from the rated terminal voltage of the machine to 315 kV. Two single circuit, 250 km long, 315 kV transmission lines will connect the Muskrat Falls switchyard to the switchyard at Churchill Falls. At Churchill Falls an extension to the 735 kV switchyard will include 735/315 kV autotransformers and the 315 kV transmission line terminations.

Labrador – Island Link (LIL)

The Labrador – Island HVdc Transmission System, or LIL, will be a ±350 kV bipole with a rating of 900 MW (450 MW per pole). The system will utilize line commutated converter technology. The transmission system includes 380 km of overhead HVdc transmission line in Labrador, a 30 km submarine cable crossing of the Strait of Belle Isle and 688 km of overhead HVdc transmission line on the Island of Newfoundland. The overhead transmission system will include optical fibre in the overhead ground wire for high speed communication between converter stations

The converter station in Labrador will be located adjacent to the Muskrat Falls Generating Station. The converter station on the Island of Newfoundland will be located on the Avalon Peninsula near the major load center at a location called Soldiers Pond. Soldiers Pond has been selected as the location of the converter station given that:

- it is located between the Holyrood Thermal Generating Station (which will cease production with the construction of the LIL) and the load center on the northeastern Avalon Peninsula; and
- all major 230 kV transmission lines in the region converge near this location, thereby reducing ac transmission line upgrades.

The LIL will have a nominal rating of 900 MW in bi-pole mode. In mono-polar mode each pole is capable of operating at 900 MW for ten minutes and 675 MW continuous. This arrangement prevents loss of load/load shedding on the Island of Newfoundland system for permanent loss of a pole. The 10 minute, 900 MW rating provides time for operators on the Island to start standby generation.

The Soldiers Pond converter station will include three high inertia synchronous condensers for voltage support, reactive power control, equivalent short circuit ratio and frequency support for the wide operating range of the LIL. The system is designed to withstand the temporary loss of the bi-pole (i.e. pole-to-pole faults). The Strait of Belle Isle cable crossing will include three cables (one energized spare) and switching arrangements at both cable transition compounds for redundancy.

System Upgrades Island of Newfoundland

Upgrades to the ac transmission system on the Island of Newfoundland include 230 kV circuit breaker replacements due to increase short circuit levels, conversion of units at Holyrood to synchronous condenser capability and thermal uprating of a number of 230 kV transmission lines.

Maritime Link (ML)

The Maritime Link will connect the 230 kV ac transmission system on the western portion of the Island of Newfoundland to Cape Breton in Nova Scotia. The system will be rated ±200 kV and 500 MW in bi-pole mode. Given the relatively weak connection points in both the Newfoundland and Nova Scotia systems, the voltage source converter technology will be employed.

The HVdc transmission system will consist of 130 km of overhead HVdc transmission line from Bottom Brook in Newfoundland to the Cabot Strait, 180 km of submarine cable across the Cabot Strait and approximately 46 km of overhead HVdc in Cape Breton to the NSPI ac transmission system.

To limit the impact of ML outages, an asymetrical bi-pole arrangement will be used for the VSC converters to permit mono-polar operation of ML. This, in turn, provides a mono-polar rating of 250 MW.

The addition of a new 230 kV transmission line from Granite Canal to Bottom Brook on the Newfoundland transmission system permits transfer of up to 250 MW via the ML for single 230 kV transmission contingencies on the Island of Newfoundland.

The ML will be bi-directional in design such that power and energy can be imported from the Maritimes to Newfoundland should there be a sustained forced bi-pole outage to the LIL.

NON-CONFIDENTIAL

Request IR-28:

With reference to Application, page 102, lines 4-7, please provide all publicly-available documents that discuss Ventyx's analysis for the Atlantic Energy Gateway (AEG) participants.

Response IR-28:

Please refer to SBA IR-27 Attachment 7.

Request IR-29:

With reference to Application, page 102, lines 10-17, please list all the robustness test scenarios tested by Ventyx, including any that were not reported in the Application documents.

Response IR-29:

The robustness scenarios tested by Ventyx prior to the Application filing were included in the Application documents. Since the Application was filed, robustness testing with Ventyx has continued. Following is a list of the additional robustness scenarios tested by Ventyx:

- Base load scenarios using base gas prices consistent with the ESAI base energy prices for all three alternatives.

- Base load scenarios using high gas prices consistent with the ESAI high energy prices for all three alternatives.

- Base load scenarios using low gas prices consistent with the ESAI low energy prices for all three alternatives.

- Low load scenarios using base gas prices consistent with the ESAI base energy prices for all three alternatives.

- Base load scenarios for the Other Import that vary the price of the Firm Import using the high energy price in the high price case sensitivity and the low energy price in the low price case sensitivity.

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- Base load scenarios for the Other Import using high gas prices consistent with the ESAI high energy prices and using the high energy price for the Firm Import.

- Base load scenarios for the Other Import using low gas prices consistent with the ESAI high energy prices and using the low energy price for the Firm Import.

- Base load scenarios for the Other Import using a high and low transmission capital price estimate.

- Low Load scenario for the Indigenous Wind that includes more unit retirements.

- Base load scenarios at base prices for the Maritime Link and Other Import to reflect the formula ROE approach included in the Application.

All robustness scenarios tested showed the Maritime Link to be the lowest long-term cost Alternative.

Request IR-30:

With reference to Application, page 102, lines 18-26, given that the NSP contract would be for 35 years:

(a) Why was the Strategist Planning Period of 25 years used?

(b) What was the Strategist Study Period number of years used?

Response IR-30:

(a) NS Power typically uses a 25 year planning period for long-term studies. Resource plans that are being compared will have different assets added at different times with different useful lives. It is expected that there will be some assets added in any given resource plan that are not fully depreciated by the end of the planning period. The study period comparison accounts for differences in the useful life of the assets.

(b) The study period includes the planning period plus the end effects. In the Maritime Link analysis the study period did not have a specific number of years - infinite end effects were assumed.

For capital investments, the end effects costs include the remaining lifetime of the initial investments made in the planning period plus infinite replacement-in-kind for each asset beyond 2040. For operating costs, end effects are based on the load in 2040 and assumed to continue each year beyond 2040. The net present value of this stream of costs converges to a finite sum which is the capital and operating cost end effects. The Strategist model calculates this finite sum which is added to the planning period net present value cost. In this way, the study period comparison of alternatives accounts for differences in the useful life of the capital investments and ensures an alternative is not biased by capital investments made late in the planning period.

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Request IR-31:

With reference to Application, page 103, lines 1-2, please explain whether the Strategist long-term resource planning optimization approach is able to enforce each of the following types of regulatory operational constraints, and if so, how:

(a) Annual and multi-year cumulative CO_2 emissions

(b) Annual SO_2 emissions

(c) Annual NOx emissions

(d) Annual Hg emissions

(e) Annual renewable energy standard (RES) requirements.

Response IR-31:

(a-e) Yes, please refer to SBA-IR-66.

Request IR-32:

With reference to Application, page 105, lines 6-8:

(a) Please explain whether the Strategist model is able to optimize the closure dates of generation units?

(b) If so, provide a table of the units and the range of possible retirement dates assumed in the model runs. If different across runs, provide the table for each run.

Response IR-32:

(a-b) NS Power forecasted unit retirements outside of the model based on efforts to manage planning reserve margins in the range of 20 percent as other forms of generation or firm imports were added to the system to comply with environmental requirements.

NON-CONFIDENTIAL

Request IR-33:

With reference to Application, page 106, line 6 to page 107, line 6, please explain whether Ventyx also had any role in defining the set of resource options for consideration and in the preliminary screening against the regulatory requirements.

Response IR-33:

No.

Request IR-34:

With reference to Application, page 107, Figure 6-1:

(a) Please explain why the "Other Import" alternative does not improve reliability.

(b) Among other reliability benefits, please address the capability of the increased New Brunswick – Nova Scotia interconnection capacity vs. the capability of the Maritime Link to reduce the risk of "Islanding" Nova Scotia following the loss of Nova Scotia generation.

(c) Please provide examples of a loss of generation that would result in islanding with either Maritime Link or Other Import. In providing these examples, please identify the interconnection power flow responses following the same loss with Maritime Link or Other Import.

Response IR-34:

(a) Transmission through New Brunswick does not provide any additional reliability as it does not provide access to new resources. This infrastructure is already committed. Please refer to McMaster IR-06.

(b) The existing capability of the New Brunswick-Nova Scotia interconnection is limited to both the transfer capacity following the loss of the existing single 345 kV line and the system conditions in New Brunswick at the time. Increasing the New Brunswick – Nova Scotia tie capacity and the Maritime Link both reduce the risk of islanding Nova Scotia following the loss of Nova Scotia generation. However, the capability of each option is dependent on the system conditions at the time of the event. In the event that system load in southern New Brunswick is high, and generation in Nova Scotia is lost, the resulting flows from New Brunswick to Nova Scotia may result in voltage drop in southern New

Brunswick. To stabilize the system in this event it may be necessary to separate New Brunswick from Nova Scotia and island the Nova Scotia load. The Maritime Link provides an alternate path that can both replace the native Nova Scotia generation and provide back-up for loss of Nova Scotia generation.

(c) The Nova Scotia system has been studied for the simultaneous loss of two thermal generating units at Lingan for the equivalent loss of 300 MW. In this contingency, Nova Scotia activates 10 minute reserve and reserve operating agreements to maintain system stability and meet reliability criteria. If the source of the generation is from New Brunswick and the interconnection is lost or derated due to system constraints, then Nova Scotia would need to start fast acting generation or interrupt customers to reduce load. If this generation is deficient to meet load demands, frequency will drop and under-frequency load shedding will be initiated. If the source of the generation is from the Maritime Link, the opportunity to respond with both Nova Scotia fast acting generation and in-flows from the New Brunswick interconnection already exist. The probability of system separation and need to interrupt customers or activate under-frequency load shedding would be significantly reduced.

NON-CONFIDENTIAL

Request IR-35:

With reference to Application, page 107, line 8, the following questions refer to the Renewable Electricity Regulations ("Regulations") made under Section 5 of the Electricity Act, as amended January 17, 2013:

(a) Sections 5(1), 6(1), and 6A(1) of the Regulations require each load-serving entity to supply its customers with renewable low-impact electricity or renewable electricity in an amount equal to or greater than a mandated percentage of the total amount of electricity supplied to its customers as measured at the customers' meters for that year. Please provide the distribution loss factor for 2012 and the forecasted distribution loss factors for 2013 through 2020. In responding to this question, the distribution loss factors should represent the distribution losses (on a percentage basis) between the NSPI load bus (Point of Supply or Delivery Point) and the aggregate of all customer meters.

(b) Identify the facility name, installed capacity, technology type, and location of each of the generation resources that NSPI plans to rely on to meet its renewable electricity standard requirements for 2013 through 2020, inclusive. Indicate which of these resources are currently under contract, which specific resources are required under the Regulations, and which resources are still in development.

(c) For each resource identified in sub-part (b) above, provide the expected annual MWh output from each of these resources for the period 2013 through 2020, inclusive, that NSPI will plan to use toward meeting its renewable electricity standard obligation in each year. For wind resources, both existing and proposed, provide all available data, information, and analyses regarding the expected energy profile.

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Response IR-35:

(a)

Year	T&D Loss Factor*
2012	7.28%
2013	7.11%
2,014	7.22%
2,015	7.20%
2,016	7.19%
2,017	7.21%
2,018	7.21%
2,019	7.21%
2,020	7.22%

* Expressed as a percentage of generation

(b) In addition to the energy from the Maritime Link Project, please refer to CanWEA IR-01 Attachment 1 for present and future planned wind generation.

(c) Please refer to Appendix 6.02 of the Application, Tables 2.1 and 2.2.

Please also refer to SBA IR-67 (c).

Wind farm annual energy output is forecast to be constant over the operating life of the wind farm.

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Request IR-36:

With reference to Application, page 107, lines 8-9:

(a) Please cite the section(s) in the Regulations that states that any resource alternative considered for 2020 must qualify as renewable electricity.

(b) While additional renewable resources are required to meet the 40% Renewable Electricity Standard in 2020, is there a role for additional natural gas generation to substitute for coal generation in Nova Scotia that may be retired? If no, please explain.

Response IR-36:

(a) Section 5(1) of the Maritime Link Cost Recovery Process Regulations requires NSPML to demonstrate that the Maritime Link Project is consistent with obligations under the Electricity Act and other environmental obligations. Section 6A of the Renewable Electricity Regulations, which are issued under the Electricity Act, contains the requirement that beginning in 2020 NS Power must supply its customers with a minimum of 40 percent renewable energy. Resource alternatives that are not renewable would fail to meet this legal requirement and are therefore not valid alternatives to the Maritime Link Project because they would not be consistent with obligations under the Electricity Act. Please refer to Section 6.1.2 of the Application.

(b) Yes, natural gas is included as resource option in each of the alternatives for the non-renewable electricity requirements.

Request IR-37:

With reference to Application, page 107, lines 8-9:

(a) Why did the analysis of alternatives not contemplate blends of two or more generation and/or transmission technologies or projects?

(b) Is it possible that a 10% slice of Muskrat Falls generation coupled with additional indigenous wind in Nova Scotia might constitute a more economical solution than the Maritime Link Project?

(c) If no, please provide all studies, memoranda or related information supporting your response.

Response IR-37:

(a) Please refer to SBA IR-70.

(b) There is no option to acquire 10 percent of the output of Muskrat Falls. By 2015, the Nova Scotia system will have approximately 500 MW of wind on the system; please refer to Appendix 6.02. As explained in the Application, additional wind will require additional capital cost to provide back-up capacity and integration on the system.

(c) Please refer to the Alternatives Analysis contained in the Application for an explanation of the approach to the analysis and results.

NON-CONFIDENTIAL

Request IR-38:

With reference to Application, page 107, lines 10-11, please provide documentation for the claim that additional natural gas generation is only possible after 2020 as a backup to wind generation.

Response IR-38:

The Application reference above describes the role natural gas may play after 2020. It was not intended to make the claim above. In fact in each alternative, natural gas is available as a resource for non-renewable electricity requirements throughout the entire study period. Please refer to EAC IR-32 for the natural gas GWh production by year for each of the alternatives.

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Request IR-39:

With reference to Application, page 108, line 8, when has NSPML assumed that production will begin at Deep Panuke?

Response IR-39:

NSPML has not made any assumption concerning when production will begin at Deep Panuke.

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Request IR-40:

With reference to Application, page 108, line 9, please provide historical and projected production data in support of the characterization that Offshore Eastern Canada production is declining and will continue to decline.

Response IR-40:

Please refer to the SOEP production reports on the CNSOPB website:
http://www.cnsopb.ns.ca/offshore-activity/weekly-activity-reports

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Request IR-41:

With reference to Application, page 108, lines 10-11, please provide predictions of future offshore expansion and production costs in the Maritimes and costs of continental US production.

Response IR-41:

NSPML does not have access to future offshore expansion and production costs, however Encana has publically stated that the Deep Panuke project requires gas prices to be in the $6-7/MMBtu range to be profitable. On shore production, specifically shale gas that is making up the bulk of new supply, is much lower cost than that, with break even prices ranging widely, depending on the liquids-to-gas ratios of the wells. Most shale wells are profitable at prices in the $4/MMBtu range.

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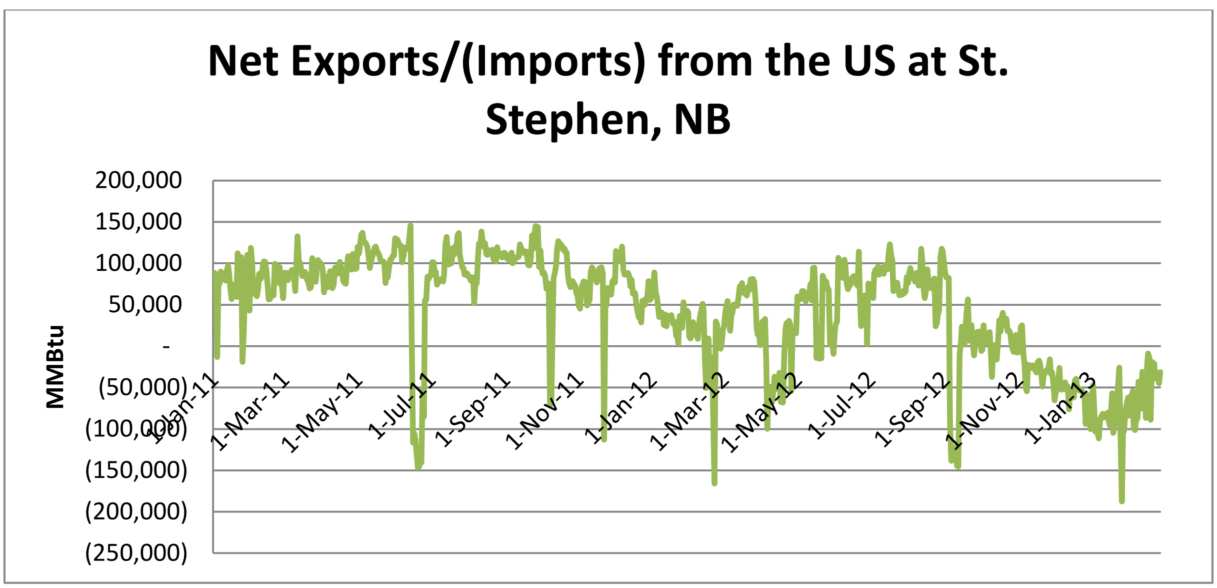
Request IR-42:

With reference to Application, page 108, line 16-18, please provide projected local production and Maritimes natural gas demand data through 2025.

Response IR-42:

SOEP is currently expected to be producing until about 2017. Exxon Mobil has publicly stated they are beginning the planning work for the decommissioning of the site. Deep Panuke is expected to have a production life of 8-13 years. Encana is indicating that it expects Deep Panuke to be on line in 2013. If this lasts to the long range of estimates, Deep Panuke may still be producing a small amount of gas in the 2025-2026 timeframe. Corridor is producing very small volumes, approximately 10,000 MMBtu/day; it is not known how long they will be in production. There currently is no other production that would be far enough along in the exploration cycle to include in the production estimates. At current demand levels in the Maritimes, with known production, there will be a requirement to import gas prior to 2025. In fact gas has been flowing into the Maritimes market from the US quite consistently. See the graph below for the daily scheduled flows at the M&NP US-Canada receipt point.



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Request IR-43:

With reference to Application, page 108, line 19, please define what available volume would be "sufficient" for Nova Scotia to import from Canaport.

Response IR-43:

Canaport must be willing to sell whatever volumes they could secure to provide NS Power with supply certainty and that world prices have been such that cargos have been attracted to Canaport.

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Request IR-44:

With reference to Application, page 108, lines 19 to 21:

(a) Please provide any forecast(s) relied upon of LNG prices in the EuroZone, New Brunswick, and New England.

(b) Who prepared such forecast(s)?

Response IR-44:

Please refer to the Nova Scotia Power Confidential FAM data room, binder titled "PIRA Scenario Planning Service: Annual Guidebook 2012".

REDACTED

Request IR-45:

With reference to Application page 108, lines 22-23:

(a) Please define what pipeline expansion volume would be sufficient to meet northern New England demand and Maritimes demand.

(b) Please provide the gas demand forecasts for Northern New England and the Maritimes underlying the response to (a).

(c) Please provide any reports or work papers that estimate the capital cost or firm transportation contract cost to procure additional natural gas from the U.S.

(d) Why would pipelines into New England sufficient to meet northern New England demand and Maritimes demand be required?

(e) Is it possible that interconnect flow from Tennessee through the Joint Facilities System into Maritimes & Northeast (M&N) can be sufficient to satisfy the gas requirements in Northern New England and the Maritimes without substantial facility improvements?

(f) Is reversal of flow on M&N technically feasible at low incremental capital cost by Spectra Energy?

(g) Is it possible that interconnect flow from Portland Natural Gas Transmission System (PNGTS) into the Joint Facilities System for redelivery into M&N can be sufficient to satisfy the gas requirements in Northern New England and the Maritimes without substantial facility improvements?

REDACTED

(h) Has NSPML reviewed the pipeline project submissions filed by Millennium, National Fuel Gas (NFG), Empire Pipeline, and Tennessee at the Federal Energy Regulatory Commission to reverse the flow from New York to Ontario to accommodate Marcellus shale gas production? If yes, would you agree with the statement that pipelines operating in the Northeast have been able to achieve regulatory certification to reverse the flow of gas into Canada at a low marginal cost relative to the original cost of pipeline construction? If no, please explain the basis for your response.

Response IR-45:

(a-c) Based on current demand numbers for customers on M&NP US, Canada and PNGTS there is already a shortfall in pipeline capacity into the region. Peak demand for the three systems (PNGTS, M&NP US and M&NP Canada) during the November 2012-February 2013 timeframe was [redacted] MMBtu (180,000 MMBtu for PNGTS, 254,000 MMBtu for M&NP US and [redacted] MMBtu for M&NP Canada). The only capacity coming into the region is PNGTS and its' maximum is approximately 275,000 MMBtu/day. This is a shortfall of over [redacted] MMBtu/day

(d) Pipelines into New England sufficient to meet northern New England demand and Maritimes demand would be required because Maritimes gas production is projected to decline and there is currently insufficient pipeline capacity coming into the region to meet demand.

(e) No. The northern end of the Tennessee Gas Pipeline (TGP) is currently operating at either maximum capacity or close to maximum capacity.

(f) Natural gas is currently capable of flowing from M&NP US to M&NP Canada. Incremental capital investment is required to meet demand in Canada.

REDACTED

(g) The PNGTS system has a through-put capacity of between 250,000-275,000 MMBtu's/day. Maximum daily consumption on the PNGTS system during the November 2012-February 2013 timeframe was 180,000 MMBtu's. This leaves between 70,000-95,000 MMBtu's to flow into the Joint Facilities. Demand on M&NP US system during this same time frame was as high as 254,000 MMBtu/day. The M&NP Canada system experienced demand as high as [redacted] MMBtu/day during this same time frame. If there is less than 100,000 MMBtu/day of spare capacity on PNGTS and both M&NP US and Canada have demand of over [redacted]/MMBtu/day this would indicate that interconnect flow cannot be relied upon to meet the gas requirements in Northern New England and the Maritimes.

(h) NSPML is generally aware of the pipeline projects mentioned but has not reviewed the filings mentioned.

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Request IR-46:

With reference to Application, page 112, lines 20-21:

(a) Please provide all documents, including emails, from Emera that supports its expectation that tidal power may become commercial on a modest scale in 2020.

(b) Please state the scale of tidal power (in MW and annual GWh) that Emera considers to be a "modest" level.

Response IR-46:

(a-b) Please refer to UARB IR-47.