NON-CONFIDENTIAL

Request IR-101:

With reference to Application, page 146, Section 8.2.4:

(a) **Please provide the quantity of Nalcor Surplus Energy assumed to be taken at cost by NSPI when it cannot be transmitted through New Brunswick by month over the study period.**

(b) **Please identify the generators assumed to back down in connection with the energy requested in part (a) and the associated reductions in fuel consumed and emissions reductions.**

Response IR-101:

(a) As the energy is cost neutral this was not modeled.

(b) Please refer to NSUARB IR-11.

NON-CONFIDENTIAL

Request IR-102:

With reference to Appendix 2.02, page 32, Section 2.1(h), if Emera exercises its option under this section, Emera is responsible for all of the Additional Capital Costs while Nalcor owns the Transmission Rights associated with the additional capacity and Nalcor's use of the Additional Transmission Rights shall be on reasonable commercial terms.

(a) Will these reasonable commercial terms include compensation to Emera and ultimately to Nova Scotia ratepayers for the portion of the Additional Capacity Costs that would be associated with Nalcor's use of the Additional Transmission Rights? If not, why not?

(b) What will be the impact of the Additional Transmission Rights on the Nova Scotia Transmission Utilization Agreement (NSTUA)?

(c) Will there be a need to amend the NSTUA? If not, why not?

(d) In the event that the NSTUA is amended, how will that affect other downstream Agreements like the New Brunswick Transmission Utilization Agreement and the MEPCO Transmission Rights Agreement?

Response IR-102:

Section 2.1(h) provides that the ML-JDC (and therefore both parties) must agree on the required Additional Development Activities, and the parties will have discussed the "Additional Transmission Rights Terms". Therefore:

(a) It is impossible to determine the "Additional Transmission Rights Terms" unless and until:

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(i) The ML-JDC approves the required Additional Development Activities;

(ii) Emera has confirmed in writing that it will pay all "Additional Capacity Costs" and;

(iii) Emera exercises its option.

(b) This is difficult to determine at this stage. The current Nova Scotia Transmission Utilization Agreement does not contemplate any additional rights to Nalcor beyond that provided for in that agreement. The impact on NS Transmission rights will be part of the negotiations referred to in Section 2.1(h). Outlining possible terms at this stage could prejudice the position of Emera in these negotiations.

(c) Please refer to part (b).

(d) This is difficult to determine at this stage. The current NBTUA and MEPCO Agreement does not contemplate any additional rights to Nalcor beyond that provided in those agreements. The impact on NB Transmission Rights and MEPCO Rights will be part of the negotiations referred to in Section 2.1(h).

NON-CONFIDENTIAL

Request IR-103:

With reference to Appendix 2.02, page 45, Section 4.7, what provision is there for NS Ratepayers through the UARB, the Consumer Advocate, or organizations representing the interests of Nova Scotia ratepayers to have sufficient access to the Maritime Link Project documents to identify and track potential cost overruns?

Response IR-103:

As a public utility, NSPML remains subject to UARB oversight and authority. The provisions of the Public Utilities Act, including the ability of the UARB to obtain necessary information from time to time, will apply to NSPML. NSPML would expect that the Consumer Advocate and other intervenors will have the opportunity in the normal course to participate in future applications to establish revenue requirement and set assessments.

Request IR-104:

With reference to Appendix 2.02, page 48, Section 5.3:

(a) Section 1.1. – "Definitions" notes that System Impact Studies are requested by the JDC-ML. Is it the intent in section 5.3 that Parties will carry out System Impact Studies at the request of the JDC-ML?

(b) Does the JDC-ML play any role in the review / approval of System Impact Studies?

Response IR-104:

(a) The parties are responsible for causing system impact studies to occur and for approval of system impact studies, however the JDC-ML may request system impact studies as the parties' representative committee.

(b) The ML-JDC may review the System Impact Studies, but the approval of such System Impact Studies is by the Party responsible, after having taken into account the comments of the Party.

NON-CONFIDENTIAL

Request IR-105:

With reference to Appendix 2.02, pages 63-64. Section 8.2(e):

(a) Why is Emera responsible for the Unapproved Overrun plus any applicable Financing Costs in the amount of up to 5% of the UARB Approved Amount?

(b) Why is Nalcor responsible for the unapproved Overrun plus the applicable Financing Costs that exceed 5% up to 10% of the UARB Approved Amount?

(c) Why do the Parties subsequently split on an equal basis any of the Overrun Amount and applicable Financing Costs that exceed 10% of the UARB Approved Amount?

(d) With respect to sub-parts (a) through (c) above, why is this apportionment approach preferable to the Parties splitting any Unapproved Overrun and applicable Financing Costs on a 50/50 basis?

Response IR-105:

The parties agreed to execute all projects employing rigorous project management principles and are confident that cost over runs can be mitigated. The joint benefit of the Maritime Link and the joint oversight of the the JDC-ML resulted in the terms referred to in questions (a) through (d), which were negotiated by the parties in the agreements referenced in Appendix 2 of the Application as a reasonable allocation of risk given that;

(i) Nalcor is the contracting party solely responsible for the successful completion of the Lower Churchill Project assets including cost management for the LTA, LIL and MF;

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(j) Emera is the contracting party and ultimately responsible for successful completion of the Maritime Link including cost management;

(ii) Emera owns the Maritime Link for the first 35 years;

(iii) Nalcor has a reversionary interest after 35 years.

NON-CONFIDENTIAL

Request IR-106:

With reference to Appendix 2.02, pages 65-67, Section 8.6, if Nalcor exercises the PPA Option it appears that Emera has no other choice but to use commercially reasonable efforts to cause the PPA Option Agreements to come into effect and to purchase from Nalcor the Nova Scotia Block for a term of 35 years. Is this interpretation of the Agreement language correct? If no, please explain.

Response IR-106:

Please refer to UARB IR-121.

NON-CONFIDENTIAL

Request IR-107:

With reference to Appendix 2.03, page 18, the Nova Scotia Block is defined as equivalent to 0.98 TWh of energy annually. In the definition provided on Page 9 of the Application the Nova Scotia Block is calculated to be 0.986 TWh. Page 33 of the Application notes that, "…The NS Block, estimated to be 895 gigawatt hours per year, will be delivered to Nova Scotia…" Please provide a clarification of the proper energy equivalence of the Nova Scotia Block.

Response IR-107:

The 0.986 TWh is NSPML's 20 percent share of the Muskrat Falls generating station's annual electricity production (4.93 TWh x 20 percent). The 895 GWh (or 0.895 TWh) is after 9.2 percent transmission losses are taken into account and represents the amount of electricity delivered to Woodbine.

NON-CONFIDENTIAL

Request IR-108:

With reference to Appendix 2.03, page 18-19, the Nova Scotia Block is defined as including Supplemental Energy. However in Figure 2-1 of the Application on page 33, the Nova Scotia Block and Supplemental Energy are listed as separate energy blocks.

(a) Please clarify whether or not the Nova Scotia Block includes Supplemental Energy.

(b) If the Nova Scotia Block includes the Supplemental Energy block please specify the energy amounts (GWh/year) for the energy that is provided all year, on-peak and the energy that is provided in the winter months, off-peak.

Response IR-108:

(a) The NS Block includes Supplemental Energy.

(b) The NS Block will provide 153 MW for the 16 peak hours during the 35 year Agreement. It will also provide approximately 200 MW for the 8 off-peak hours during the winter months during the initial 5 years of the Agreement.

NON-CONFIDENTIAL

Request IR-109:

With reference to Appendix 2.03, pages 44-48, Sections 8.3, 8.4, 8.5, and 8.6, please explain whether or not Nova Scotia ratepayers bear the costs of Nalcor's failure to deliver the Nova Scotia Block. Please provide your explanation in terms of failure to deliver due to a Forgivable Event or failure to deliver for any reason other than a Forgivable Event.

Response IR-109:

(a) Forgivable Event – In the case of failure to deliver due to a forgivable event, Nalcor shall be obligated to redeliver an equivalent amount of energy in accordance with Section 8.5 of the Energy and Capacity Agreement and Section 5 of Schedule 5 of that Agreement. Nova Scotia ratepayers would be responsible for the cost of procuring the required replacement energy for the duration of the failure and would receive the benefit of the redelivered energy when received.

(b) Non-Forgivable Event – In the case of failure to deliver by Nalcor for a reason other than a forgivable event, Nalcor shall be obligated to redeliver either 120 percent of the Market Price Equivalent Energy or 120 percent of the Marginal Cost Energy (as determined by Emera) in accordance with Section 8.5 of the Energy and Capacity Agreement and Section 5 of Schedule 5 of the Agreement. Nova Scotia ratepayers would be responsible for the cost of procuring the required replacement energy for the duration of the failure but they are also entitled to the penalties and relief stipulated for such failure. If the non-Forgivable Event was caused by a Government Action, the Government of Newfoundland & Labrador indemnifies for losses as is provided for in the Inter-Provincial Agreement.

NON-CONFIDENTIAL

Request IR-110:

With reference to Appendix 2.03, page 54, Section 10.3, please explain whether or not there are any compensation mechanisms in place for Nova Scotia customers in the event that energy transmitted for the Nova Scotia Block is curtailed for whatever reason. Provide reference to the relevant section(s) in any of the agreement.

Response IR-110:

Please also refer to CA-SBA IR-109.

NON-CONFIDENTIAL

Request IR-111:

With reference to Appendix 2.03, page 74:

(a) To what extent, if any, can discretionary operation of the Churchill Falls facility influence the size of the Nova Scotia Block and/or the availability of off-peak power to support the Supplementary Energy?

(b) Under what circumstances, if any, would discretionary operation of the Churchill Falls facility result in a significant reduction in the Nova Scotia Block?

(c) What provisions of the Nalcor-CF (L) Co Water Management Agreement can influence the size of the Nova Scotia Block, and its scheduling flexibility initially and over time?

(d) Will any provisions in the Renewed (2016-2041) Power Contract between Hydro Quebec and CF (L) Co affect the Water Management Agreement and the size and/or scheduling flexibility of the Nova Scotia Block?

Response IR-111:

The NS Block is not subject to the operation of the Churchill Falls generating station or the operation of the Water Management Agreement. Please refer to NSUARB IR-70.

Request IR-112:

With reference to Appendix 2.03, pages 84-86 and Application, page 79, lines 8-23, Supplemental Energy is intended to be compensation for the difference between a 35 year term and a 50 year term for delivery of the Nova Scotia Block Energy.

(a) Is the financial model referenced in paragraph 7 of Schedule 4 essentially the same model as appears in Appendix 4.01, except for the ability to consider a 50 year term?

(b) Please provide a detailed explanation of how the current estimate of the Supplemental Energy annual amount was determined, including assumptions of annual costs over 35 and 50 year amortizations, the calculation of levelized unit energy costs, and the determination of the Supplemental Energy amount.

(c) Please explain how off-peak energy in the winter months and compressed into the first five years of operation provides reasonable compensation to NSPML for the shorter contract term.

(d) In determining the formula for Supplemental Energy, was any consideration given to the relative replacement value or opportunity cost of energy at different times of day, seasons, and years within the delivery term? If no, why not?

Response IR-112:

(a) Yes.

(b) The Supplemental Energy is determined by looking at total Project costs over 50 years (including depreciating assets over 50 rather than 35 years). A levelized price is then calculated. The period is then changed to 35 years (depreciable assets then fully depreciated over 35 rather than 50 years), and the amount of Supplemental Energy per year for the first five years is solved for so that the levelized cost is equal to that under the 50 year scenario. Additional detail is contained in Schedule 4 of the Energy and Capacity Agreement (Appendix 2.03).

(c-d) Please see response to NSUARB IR-16.

NON-CONFIDENTIAL

Request IR-113:

With reference to Appendix 2.04, pages 7-8:

(a) Please explain the difference, in reservation and curtailment terms, between Conditional Firm Point-to-Point Transmission Service and Firm Point-to-Point Transmission Service.

(b) Please explain the need to have both Conditional Firm Point-to-Point Transmission Service and Firm Point-to-Point Transmission Service for the Maritime Link transactions.

Response IR-113:

(a) Conditional Firm Point to Point Transmission describes the service that Nalcor has through the NS transmission system. An example of the difference between the two would be on the effect of a transmission element failing. With firm point to point service the system would be designed to allow any single element to fail and the flow of the full reservation would not be affected. Under conditional firm the failure of one element of the transmission system can affect the flow of the reservation.

(b) The Maritime Link is comprised of two cables each with the capability to carry 250 MW; this means that the link can flow 250 MW on a firm basis and 250 MW non-firm, as the failure of one of those cables will still allow for the flow of 250 MW. As NSPML is expected to have 170 MW of firm energy, the remaining firm energy (250 MW-170 MW=80 MW) of 80 MW is Nalcor’s.

NON-CONFIDENTIAL

Request IR-114:

With reference to Appendix 2.04, pages 25-26, Section 3.3(f), please explain the impact to Nova Scotia customers, including an analysis of any costs the customers will bear, as a result of the curtailment of Transmission Service on the Maritime Link.

Response IR-114:

In terms of a curtailment in accordance with Section 3.3(f), costs would be similar to any other curtailment of any of NS Power's generation facilities. In addition, as energy is merely deferred and not lost, Nova Scotia customers will receive the benefit of subsequent savings when the deferred energy is subsequently redelivered.

NON-CONFIDENTIAL

Request IR-115:

With reference to Appendix 2.04, page 64, Schedule 2, please provide an indication of when the Parties expect to negotiate and finalize the Maritime Link Scheduling Process, for inclusion in the Agreement.

Response IR-115:

As stated in Schedule 2 of the Maritime Link (Nalcor) Transmission Service Agreement, the Maritime Link Scheduling Process will be negotiated prior to the Commercial Operation Date. The parties have not yet developed a more precise timetable for the negotiation and drafting of the scheduling process.

NON-CONFIDENTIAL

Request IR-116:

With reference to Appendix 2.05, pages 22-24, Section 3.3(f), please explain the impact to Nova Scotia customers, including an analysis of any costs the customers will bear, as a result of the curtailment of Transmission Service on the Maritime Link.

Response IR-116:

Please refer to CA-SBA IR-114.

NON-CONFIDENTIAL

Request IR-117:

With reference to Appendix 2.05, page 58, Schedule 2, please provide an indication of when the Parties expect to negotiate and finalize the Maritime Link Scheduling Process, for inclusion in the Agreement.

Response IR-117:

As stated in Schedule 2 of the Maritime Link (Emera) Transmission Service Agreement, the Maritime Link Scheduling Process will be negotiated prior to the Commercial Operation Date. The parties have not yet developed a more precise timetable for the negotiation and drafting of the scheduling process. See also SBA IR-115 with respct to the Maritime Link (Nalcor) Transmission Service Agreement.

NON-CONFIDENTIAL

Request IR-118:

With reference to the Nova Scotia Transmission Utilization Agreement (NSTUA – Appendix 2.06), Emera commits to schedule transmission interchange from Woodbine, Nova Scotia to the New Brunswick border of up to 330 MW (Section 2.1(b), p, 19) on behalf of Nalcor and to absorb any costs associated with necessary upgrades (estimated in the Application at page 144 to cost $31.5 million) and redispatch of Nova Scotia generation (estimated in the Application at page 144 to cost $6 to $8 million per year) to accommodate that transmission. Nalcor will pay the NSPI OATT tariff for this transmission service.

(a) What Emera entity is the obligated party under this agreement?

(b) Are there any circumstances where Emera would seek to allocate all or a portion of the resultant upgrade costs and redispatch costs to NSPI? If your answer is anything other an unequivocal no, please explain what the circumstances are and the economic or operational rationale that would support such an allocation to NSPI. Will these costs be recovered from Nova Scotia ratepayers?

(c) How will the redispatch costs be tracked, managed and reconciled?

Response IR-118:

(a) NSP Maritime Link Inc. (NSPML) is the Emera entity obligated under the NSTUA.

(b) Pursuant to the Agency and Service Agreement between NSPML and NS Power, NS Power will provide, on NSPML's behalf, the Transmission Facilitation Service described in the NSTUA and is responsible for any resultant up-grade costs to the NS transmission system. NS Power is also responsible for redispatch costs. NSPML is responsible for upgrades to the Woodbine substation necessary to allow the interconnection of the Maritime Link with the Nova Scotia Transmission System.

NS Power anticipates that the costs of providing the Transmission Facilitation Service will be offset by "Applicable Tariff Charges" and other amounts payable by Nalcor under the NSTUA in respect of the Transmission Facilitation Service. In accordance with Section 3.3 of the Agency and Service Agreement, if, in any 60 month period, NS Power's prudently incurred costs in providing the Transmission Facilitation Service are greater than amounts payable by and received from Nalcor, NSPML is to pay the difference to NS Power. In that event, NSPML would seek recovery of such amounts from Nova Scotia customers through the Project Cost Assessment.

Provision of the Transmission Facilitation Service is part of the consideration associated with the agreements as a whole and, in particular, the delivery by Nalcor of the NS Block.

(c) Redispatch costs will be tracked, managed and reconciled by NS Power using its existing fuel and generation dispatch reconciliation processes. Specific procedures will be developed prior to Maritime Link going in service.

NON-CONFIDENTIAL

Request IR-119:

With reference to Appendix 2.06, page 24, Section 2.1(b), please explain the considerations behind scheduling only 150 MW of transmission capacity in January, February and December as opposed to 330 MW for the rest of the year.

Response IR-119:

The schedule of transmission capacity under the NSTUA was set by Nalcor Energy according to their needs, which is understood to reflect a higher domestic load in those (winter) months.

Request IR-120:

Appendix 2.06, page 25, Section 2.1(b), states that, "…Nalcor shall give Emera adequate Notice (which may be as long as seven years depending on the circumstances) of its good faith estimate of any increase in the amount of transmission Capacity required by Nalcor above the amount described in the above table in sufficient time to allow Emera to plan, build and commission necessary upgrades and additions required to the NS Transmission System before the end of the Initial Term or any Subsequent Term…."

(a) Please explain whether or not Nalcor contemplates requesting additional transmission capacity over and above 330 MW before the end of the Initial Term.

(b) If Nalcor contemplates requesting additional transmission capacity over 330 MW, please explain how that affects the provision and delivery of the Nova Scotia Block.

(c) In the event that additional transmission upgrades are required for the delivery of the Nalcor request, please explain how and when Board approval for the cost recovery ofthose additional upgrades will be sought.

Response IR-120:

(a) At this time it is not known whether or not Nalcor contemplates requesting additional transmission capacity over and above 330 MW before the end of the Initial Term.

(b) The 330 MW that Nalcor has indicated it may schedule in accordance with the NSTUA is unrelated to the delivery of the NS Block. Similarly, any request by Nalcor for additional transmission capacity over 330 MW for a Subsequent Term of 15 years as contemplated under the NSTUA would not affect the provision and delivery of the NS Block.

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(c) Board approval will be sought for the cost recovery of any such additional upgrades in accordance with the Public Utilities Act and such other regulatory requrements as are applicable at the time approval is sought.

NON-CONFIDENTIAL

Request IR-121:

With reference to Appendix 2.06, page 27, Section 2.2(a), please provide a copy of the TSR 400 application requesting Long Term Firm Point-to-Point Transmission Service under the NS OATT.

Response IR-121:

Please refer to Attachment 1 - the Long Term Firm Point-to-Point Transmission Service Request for TSR 400.

Nova Scotia
POWER
An Emera Company

energy everywhere.

July 22, 2011

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1:56 pm

Nova Scotia Power Inc.
P.O. Box 910
Halifax, NS
B3J 2W5

Attention: NSPI System Operator

Dear Sir:

Re: Application for Long Term Firm Point to Point Transmission Service

Pursuant to Section 17 of the Open Access Transmission Tariff (OATT), Nova Scotia Power Incorporated (NSPI) hereby applies for Long Term Firm.

The information required by Section 17.2 (OATT) is:

i. Nova Scotia Power Inc.
   P.O. Box 910
   Halifax, NS
   B3J 2W5
   mark.sidebottom@nspower.ca
   (902) 428-6600

ii. NSPI, an electric utility, is an Eligible Customer under the OATT.

   The path will be NS-NB

   The Delivery Party will be NSPI or its assignee.

   The Receiving Party will be NSPI or its assignee.

iii. The location of the generating facility supplying the capacity and energy will be the Province of Newfoundland and Labrador.

   The load to be served by the capacity and energy is in markets located in other jurisdictions beyond the Nova Scotia/New Brunswick border.

iv. NSPI expects the method of supply to be HVDC to the terminal station at the point of receipt.

v. NSPI expects the annual energy supply shall be approximately 2 TWh at a capacity of 330 MW at the point of delivery.

vi. The Service Commencement date is January 1, 2017 and the term of the requested Transmission Service is 50 years.

NSPI requests 330 MW of transmission capacity for each of Point of Receipt and Point of Delivery.

We confirm that the deposit, which we understand is the amount of $709,015 required under Section 17.3, can be charged against NSPI account number 1-690-000-003-0000 This amount will be sufficient for satisfaction of the deposit amount.

NSPI has withdrawn TSR 300 (Wreck Cove Point of Receipt). This application is not "in addition to" but would "replace" the original request (TSR 200).

Yours truly,

Mark Sidebottom
GM, Power Production

cc: Nicole Henneberry

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Request IR-122:

With reference to Appendix 2.06, page 27, Section 2.2(e), please identify any existing transmission constraints on the NS Transmission System that would prevent the NS Nominated Transmission Capacity from being scheduled and delivered over the NS Transmission System.

Response IR-122:

The existing transmission constraints in NS as of Feb 2013 that are relevant to the IR are as follows:

- NS export to NB is 350 MW non-firm and 80 MW firm.

- ONI (Onslow Import) is 1025 MW, which is the total MW flow on the 345 kV, 230 kV, and 138 kV lines into 67N-Onslow and 1N-Onslow substations from the east.

- CBX (Cape Breton Export) is 900 MW in winter and 700 MW in summer, which is the total MW flow on the 345 kV, 230 kV, and 138 kV lines from Cape Breton to the Mainland in NS.

All transmission constraints assume that Special Protection Systems are armed with sufficient generation rejection.

NON-CONFIDENTIAL

Request IR-123:

With reference to Appendix 2.06, page 27, Section 2.2 (f), will Emera be obligated to redispatch to alleviate any constraints caused by any other events other than Forgivable Events?

Response IR-123:

For clarification, 2.2(f) indicates that there shall be no obligation to redispatch to alleviate any constraints caused by a Forgivable Event. If there is no Forgivable Event in favour of NS Power, then NS Power would be obligated to redispatch in order to alleviate any constraints.

NON-CONFIDENTIAL

Request IR-124:

With reference to Appendix 2.06, page 33, Section 2.3(b) (xi):

(a) Please explain why Nalcor shall not be obliged to reimburse Emera for Ancillary Service charges attributable to Redispatch.

(b) Under what circumstances, if any, would Emera seek to pass on the non-reimbursed redispatch costs to Nova Scotia ratepayers?

Response IR-124:

(a) It is NSPML's obligation to provide the path through Nova Scotia. That path is created, at times, by redispatching the NS generation to avoid more costly transmission upgrades, and therefore the transmission provider's cost.

(b) Please refer to Section 3.3 of the Agency and Service Agreement and Section 8.2.1 of the Application.

NON-CONFIDENTIAL

Request IR-125:

With reference to Appendix 2.06, page 33, Section 2.3(b)(xii), please explain what happens in the event Emera fails to transmit the NS-NTQ for any other reason other than a Planned Maintenance Period, a Force Majeure or Safety Event.

Response IR-125:

A Force Majeure, a Planned Maintenance Period, a Safety Event or an action required to be taken by NSPML or Nalcor to comply with the requirements of Good Utility Practice constitute "Forgivable Events" under the Nova Scotia Transmission Utilization Agreement. Pursuant to Section 2.7 of the Agreement, NSPML is not in breach of the Agreement if it fails to transmit the NS-NTQ by reason of a Forgivable Event affecting the Emera Facilities. If NSPML fails to transmit the NS-NTQ for any other reason, it may be found to be in breach of the Agreement and, in that event, would be liable to Nalcor for liquidated damages calculated in accordance with Section 8.5 of the Agreement.

NON-CONFIDENTIAL

Request IR-126:

With reference to Appendix 2.06, page 34, Section 2.6(a) (i) and page 36, Section 3.3:

(a) Please explain why there would ever be a need for Nalcor to make an application for transmission service under the NS OATT for transmission service from the Delivery Point to the Nova Scotia-New Brunswick Border outside of the Nova Scotia Transmission Utilization Agreement.

(b) In the event that Nalcor does make an application for transmission service under the NS OATT what will be the relationship between deliveries made under that transmission service arrangement and deliveries made under the Nova Scotia Transmission Utilization Agreement?

(c) In the event that Nalcor makes an application for transmission service under the OATT, does that mean that both Nalcor and Emera will be classified as Transmission Customers under the NS OATT for deliveries from the Delivery Point to the Nova Scotia-New Brunswick Border?

Response IR-126:

(a) We are unaware of any need for Nalcor to make an application for transmission service outside of the Transmission Utilization Agreement.

(b) There would not be any relationship between the two deliveries. They would be separate transactions.

(c) Yes, but for separate reservations.

NON-CONFIDENTIAL

Request IR-127:

With reference to Appendix 2.06, page 35, Section 2.6(c):

(a) **Please explain how there could be a conflict between the Nova Scotia Transmission Utilization Agreement and the NS OATT when section 2.6(b) of the Nova Scotia Transmission Utilization Agreement specifically states that, "…Emera shall comply with the NS OATT in providing the Transmission Facilitation Service…"**

(b) **In the event of a conflict between the provisions of the Nova Scotia Transmission Utilization Agreement and the NS OATT, under what circumstances would the Nova Scotia Transmission Utilization Agreement subordinate the NS OATT?**

Response IR-127:

(a) NS Power is taking Transmission Service under the OATT and will hold the transmission reservation for Point to Point Service from the Point of Receipt to the Delivery Point. As the Transmission Customer, NS Power must comply with the NS OATT and the terms of its standard form Long Term Firm Point to Point Transmission Service Agreement. Nalcor is not taking Transmission Service under the OATT but is required to comply with the terms of the Nova Scotia Transmission Utilization Agreement (NSTUA) with NSPML, as managed by NS Power pursuant to the Agency and Service Agreement.

(b) We are unaware of any circumstances where the NSTUA would subordinate the Nova Scotia OATT. Under Section 2.6 (c) of the NSTUA, in the event of a conflict between the NSTUA and the OATT, provisions of the NSTUA prevail. While this is true for the relationship between NSPML and Nalcor, it does not relieve NS Power of its responsibility to comply with the OATT and the standard form Long Term Firm Point to Point Transmission Service Agreement.

NON-CONFIDENTIAL

Request IR-128:

With reference to Appendix 2.06, page 35, Section 2.7, will Emera be considered in breach and liable to Nalcor for any losses that are caused by an event other than a Forgivable Event affecting the Emera facilities?

Response IR-128:

Please refer to SBA IR-125.

Request IR-129:

With reference to Appendix 2.06, pages 35-36, Section 2.10:

(a) **Please explain why this provision is necessary when section 2.1(d) of the Nova Scotia Transmission Utilization Agreement states that "Emera shall use the Emera Firm Point-to-Point Transmission Service in order to facilitate the provision of the transmission Facilitation Service to Nalcor"**

(b) **Please explain under what conditions a portion of the NS-NTQ can be treated as if it were transmitted under the NS OATT using Non-Firm Point Transmission.**

Response IR-129:

(a-b) Section 2.1(d) of the Nova Scotia Transmission Utilization Agreement provides that curtailments under the NS OATT may result in curtailments of the NS-NTQ. In the event of a curtailment, pursuant to Section 2.1(d) (i) of the Agreement, any interruptible transmission customers will be interrupted prior to the curtailment of the NS-NTQ. Next, pursuant to Section 2.1(d) (ii) of the Agreement, Nalcor's Energy in excess of 80 MW will be curtailed as if it were transmitted pursuant to a Non-Firm Point-to Point Transmission Service reservation under the NS OATT.

NON-CONFIDENTIAL

Request IR-130:

With reference to Appendix 2.07, pages 20-21, Section 2.1(a):

(a) Is it the understanding of the Parties that Nalcor's use of the Bayside Rights shall only be for the Summer Period of that year?

(b) How does the summer period requirement for scheduling Bayside Rights affect scheduling in Nova Scotia as part of the Nova Scotia Transmission Utilization Agreement? Does it mean that scheduling under the Nova Scotia Transmission Utilization Agreement will also have to be for the Summer Period?

(c) In the event that Nalcor wishes to schedule energy and/or capacity through Nova Scotia, meant for delivery to the New Brunswick-Maine Border, for any period other than the summer period, how will that energy and/or capacity be scheduled through New Brunswick?

Response IR-130:

(a) Yes.

(b) Scheduling of Nalcor's rights under the NSTUA and NBTUA will be coordinated using the Scheduling Protocol attached as Schedule 2 to each of these agreements.

(c) Nalcor will be responsible for obtaining and scheduling any required transmission rights beyond the Bayside rights made available by Emera and Bayside LP under the NBTUA.

NON-CONFIDENTIAL

Request IR-131:

With reference to Appendix 2.07, page 21, Section 2.1 (c), during the last five years of the first term, how will Emera provide Equivalent Rights to Nalcor, in the event of non-renewal of Bayside Rights?

Response IR-131:

If the Bayside Rights are not renewed, Emera is obligated to use commercially reasonable efforts to obtain Equivalent Rights for use by Nalcor in accordance with the NBTUA.

NON-CONFIDENTIAL

Request IR-132:

With reference to Appendix 2.07, page 24, Section 2.5(a), and the provision that Nalcor be an Eligible Customer, must Nalcor be an Eligible Customer under the NB OATT? If no, why not?

Response IR-132:

In order to take an assignment of the Bayside rights as contemplated by Section 2.5(a), NSPML understand that Nalcor must be an Eligible Customer under the NBOATT.

NON-CONFIDENTIAL

Request IR-133:

With reference to Appendix 2.07, page 25, Section 3.1(b):

(a) When does Emera expect to construct the New Brunswick Transmission Line?

(b) Will any of the costs of the New Brunswick Transmission Line be allocable to Nova Scotia customers?

Response IR-133:

Please see CA/SBA IR-10.

NON-CONFIDENTIAL

Request IR-134:

With reference to Appendix 2.07, page 27, Section 4.1(b), please identify the documentary evidence that Emera will require from Nalcor in order to prove that it has the technical capability, in accordance with the ISO-NE Tariff, to sell capacity at or beyond the New Brunswick-Maine Border.

Response IR-134:

The documentary evidence would include items such as the following:

- For each element of the transmission path from generation source though to the market, evidence of firm transmission rights sufficient to support a sale of capacity into ISO New England.

- A commitment from Nalcor (or NL Hydro) that the capacity resource will have sufficient capacity that is not obligated outside the New England Control Area to fully satisfy the capacity sale.

- Documentation from the source control area, and all intervening control areas, demonstrating that explicit market and operating procedures exist among the intervening Control Areas to ensure that the energy required to be delivered to the New England Control Area will be guaranteed the same curtailment priority as the intervening native loads, and that none of the intervening Control Areas will curtail the transaction except in conjunction with a curtailment of native load.

NON-CONFIDENTIAL

Request IR-135:

With reference to Appendix 2.07, pages 31-32, Section 6:

(a) **Is it possible that Nalcor may acquire transmission rights on the New Brunswick Transmission Line at the same time that it is entitled to the Bayside Rights?**

(b) **In the event that Nalcor has rights to the New Brunswick Transmission Line and Bayside Rights at the same time, can Nalcor request Emera to schedule energy and/or capacity using both sets of rights at the same time or they would only be able to use one set of rights at a given time? If one set of rights at any given time, who decides?**

Response IR-135:

(a) If the proposed NB Transmission Line proceeds and is constructed and in service before the expiry of the Bayside Rights in 2026, then it is possible that Nalcor could take out and hold transmission rights over the proposed NB Transmission Line while still being entitled to the utilize the Bayside Rights.

(b) We are not aware of any restriction on Nalcor utilizing both sets of transmission rights, presuming that both are concurrently available.

NON-CONFIDENTIAL

Request IR-136:

With reference to Appendix 2.07, page 33, Section 7.1(b), please explain why in the event of a conflict between the provisions of the Agreement and the New Brunswick Tariff the provisions of the Agreement prevail.

Response IR-136:

The intent of the clause (the complete text of which is set out below), is to provide clarity and predictability to the parties as to the interpretation and enforceability of the negotiated terms of the agreement, to the extent possible.

> In the event of any conflict between the provisions of this Agreement and the provisions of the NB Tariff, for the purposes of the interpretation and implementation of this Agreement, the provisions of this Agreement shall prevail.

NON-CONFIDENTIAL

Request IR-137:

With reference to Appendix 2.08, page 18, Section 2.1, please confirm that Emera currently holds rights to the MEPCO Transmission Rights including any renewal rights and that these rights are available for assignment to Nalcor.

Response IR-137:

The MEPCO Transmission Rights are held by Bayside LP, an indirectly wholly owned entity of Emera Inc., and are available for assignment to Nalcor under the terms of the MEPCO Transmission Rights Agreement. The obligations of Emera under the MEPCO Transmission Rights Agreement have been assigned to Bayside LP.

NON-CONFIDENTIAL

Request IR-138:

With reference to Appendix 2.08, page 21, Section 2.10, please provide a listing of all the applicable Tariff Charges that Nalcor shall be responsible for and payable to ISO-NE or to MEPCO, in respect of any assignment of the MEPCO Transmission Rights or Equivalent Rights by Emera to Nalcor.

Response IR-138:

Nalcor shall be responsible for the MEPCO Grandfathered Transmission Service Agreements charges as levied under the ISO-NE tariff by and payable to MEPCO. These charges consist of a "Transmission Reservation" charge, and an "Ancillary 1" charge as applicable to the assignment period.

NON-CONFIDENTIAL

Request IR-139:

With reference to Appendix 2.08, page 22, Section 3.1(b), please explain why in the event of any conflict between the Agreement and the provisions of the ISO-NE Tariff, the provisions of the Agreement shall prevail.

Response IR-139:

The intent of the clause (the complete text of which is set out below), is to provide clarity and predictability to the parties as to the interpretation and enforceability of the negotiated terms of the agreement, to the extent possible.

> In the event of any conflict between the provisions of this Agreement and the provisions of the ISO-NE Tariff, for the purposes of the interpretation and implementation of this Agreement, the provisions of this Agreement shall prevail.

NON-CONFIDENTIAL

Request IR-140:

With reference to Appendix 2.09, page 44, Schedule, if NLH decides to participate in the Reliability Assessment Program, will NLH at that time officially become a member of NPCC?

Response IR-140:

Nalcor has the option to participate in the Reliability Assessment Program and at that time it will have to consider whether it is necessary for it to become a member of NPCC. Emera has no direct contractual ability to require it to do so.

NON-CONFIDENTIAL

Request IR-141:

With reference to Appendix 2.09, page 45, Schedule A4:

(a) Will NSPI and NLH be responsible for ACE management within their respective areas?

(b) How will NSPI and NLH coordinate with NBSO regarding ACE management, since NBSO is the Reliability Coordinator for the New Brunswick and Nova Scotia systems?

Response IR-141:

(a) Yes NLH and NS Power will balance the ACE (Area Control Error) for each of their areas relative to the tie line scheduled Maritime Link interface.

(b) NS Power as the balancing authority for Nova Scotia will deal with NBSO for ACE management on the tie line at the New Brunswick and Nova Scotia interconnection. Nova Scotia will manage ACE between New Brunswick and Nova Scotia separately using AGC (Automatic Generation Control) and based on a tie line schedule with NBSO.

NON-CONFIDENTIAL

Request IR-142:

With reference to Appendix 2.15, page 5, Section 2(a) of the Sanction Agreement notes that, "Nalcor and Emera agree to Sanction the Maritime Link simultaneously with the sanction of the Muskrat Falls Plant, the Labrador-Island Link, and the Labrador Transmission Assets."

(a) Is it the understanding of the Parties that while the UARB may not have jurisdiction over the Muskrat Falls Plant, the Labrador-Island Link, and the Labrador Transmission Assets, the approval and development of Maritime Link project is dependent on those other sanctioned projects also going ahead?

(b) If the development of the Muskrat Falls Plant, The Labrador-Island, and the Labrador Transmission Assets either stops or is delayed before the Board makes a decision on the Maritimes Link, will the Maritime Link Application be withdrawn?

Response IR-142:

(a) The Maritime Link was conditional on each of such projects being Sanctioned by Nalcor, which Sanction occurred on December 17, 2012.

(b) NSPML does not anticipate any delay or stoppage but will consider the circumstances for the delay or the stoppage and make a decision at that time.

NON-CONFIDENTIAL

Request IR-143:

With reference to Appendix 2.15, page 15, Section 5(a):

(a) If the NS Regulatory Application is denied as per Section 5(a)(i), please explain what is meant by "…Nalcor and Emera will attempt to reach a mutually satisfactory resolution of such issues with the goal of ensuring that the Maritime Link is built…"

(b) If the System Impact Studies are not satisfactory to either Emera or Nalcor as per section 5(a)(iv), please explain how a mutually satisfactory resolution can be reached if the studies are showing detrimental system impacts.

(c) If, as noted "…each Party is free to make its own decision as to the resolution of such issues in its sole and absolute discretion…", is there any possibility of the project being built if either Emera or Nalcor decides against moving forward?

Response IR-143:

(a) The Parties will attempt to negotiate new arrangements which might enable the Maritime Link to be constructed. Please also refer to Liberal IR-14.

(b) At this time there are no known issues with the sytem impact studies that would require the parties to reach such a resolution, however if there was a significant capital upgrade required that was outside the scope of the agreements, the parties would endeavour to find a way to address the issue to allow the project to proceed if practical.

(c) No, if section 5(a) applies, both parties must agree to proceed.

NON-CONFIDENTIAL

Request IR-144:

With reference to Appendix 2.15, page 15, Section 5(b), please explain whether or not the New Maritime Link will have the same scope as the proposed Maritime Link or it will be a completely different project.

Response IR-144:

The scope of the New Maritime Link, including the supporting commercial arrangements, could be different from the Maritime Link.

NON-CONFIDENTIAL

Request IR-145:

With reference to Appendix 3.01, page 9, please provide the preliminary system planning studies and conceptual design decisions completed by NSPML in consultation with Newfoundland and Labrador Hydro and NSPI.

Response IR-145:

A significant amount of the preliminary conceptual design and planning work was undertaken by Nalcor as informal designs and estimates prepared in consultation with equipment vendors. Formal study reports were not issued for most of these investigations. The essence of these investigations has been summarized in the Application and the Engineering Review document. The following study reports are attached to this response:

- Evaluation of Shoreline Grounding Sites – Please refer to Environmental Application.
- System Reinforcement Requirements (Newfoundland) – See McMaster IR-2 and Synapse IR-26.
- System Reinforcement Requirements (Nova Scotia) – See McMaster IR-2.

NON-CONFIDENTIAL

Request IR-146:

With reference to Appendix 3.01, page 14, please provide documentation supporting Hatch's statement regarding weakness of the AC transmission system at the Newfoundland sending end and relatively weak reactive power support at both ends of the DC transmission link.

Response IR-146:

The minimum short-circuit levels are provided on page 10 of the report in Hingorani IR-10 Attachment 2, and this indicates the minimum short-circuit levels for which the system is being designed. These are low levels for interconnection of the HVdc system.

NON-CONFIDENTIAL

Request IR-147:

With reference to Appendix 3.01, page 14, please explain why VSC technology is a better choice compared to the LCC technology in applications featuring weak AC transmission systems requiring additional dynamic reactive power support.

Response IR-147:

Apart from other advantages of VSC technology compared to the LCC alternative, the reactive power support capability inherent in the VSC concept enables connections to very weak networks, and even to networks lacking generation, without the need for extra reactive compensation equipment. The VSC converter consumes less reactive power in the conversion to and from DC than does an LCC converter. With an LCC converter, this increased reactive power must be supplied by adding shunt capacitors, filters and in some cases synchronous condensers. Adding passive shunt elements such as capacitors or filters effectively exacerbates the weakness of an already weak grid, and synchronous condensers will be the only workable solution for LCC applications in weak systems with low available short-circuit current.

VSC technology has the added advantage in weak grids that the VSC installation cannot only supply its own reactive power but also deliver surplus reactive power to the grid.

Request IR-148:

With reference to Appendix 3.01, page 14, please explain whether or not the LCC technology would be a preferred choice if used in conjunction with the conversion of the planned for retirement coal-fired generation in Cape Breton into synchronous condensers.

Response IR-148:

System studies have identified the need for additional reactive support and additional short-circuit capacity in Cape Breton and Newfoundland to successfully implement LCC technology on the Maritime Link Project. The mentioned initiative to convert Lingan units to synchronous condenser operation would satisfy the requirements in Cape Breton, maintaining higher short-circuit levels at the LCC terminals and supplying much of the required reactive power for conversion. If these changes were planned to be implemented regardless of the Maritime Link Project, then LCC technology would be an attractive option for the project. Since these initiatives are only required to support an LCC option, and not a VSC option, the added investment cost for these developments is an important part of the cost preference for VSC technology

NON-CONFIDENTIAL

Request IR-149:

With reference to Appendix 3.01, page 16, please provide a copy of the RFP for the cable supply contract and copies of the proposals by the proponents for the cable supply contract.

Response IR-149:

NSPML is currently in the midst of the evaluations and will begin negotiations soon. Since this competitive solicitation process is in process, proposal documents are currently not available. Due to the voluminous size of the RFP and once negotiations have concluded, we would be pleased to provide specific parts of the RFP documents upon request.

The Request for Proposal is comprised of the following parts:

<u>Part 1:</u>

General Information and Instructions to Proponents
Section 0.1 General Information for Proponents
Section 0.2 Instructions to Proponents
Section 0.3 Proposal Forms
Section 0.4 Commercial Proposal
Section 0.5 Technical Proposal Questionnaire
Section 0.6 Quality Management Questionnaire
Section 0.7 HSSE Management Questionnaire

NON-CONFIDENTIAL

<u>Part 2:</u>

Typical form of Agreement (including Exhibits 1-12)

<u>Exhibit Description:</u>

1. Scope of Work
2. Compensation
3. Subcontractors
4. Coordination Procedures
5. Company Supplied Items
6. Company Supplied Document Listing
7. Deliverables List
8. Nova Scotia and Newfoundland & Labrador Benefits
9. Performance Security
10. Declaration of Residency
11. Milestone Schedule
12. Contractor’s Facilities

NON-CONFIDENTIAL

Request IR-150:

With reference to Appendix 3.01, page 17:

(a) **If the final selection of the cable technology is the MI insulation, will the system voltage level be reconsidered in favor of +/- 250 kV?**

(b) **If not, please explain why.**

Response IR-150:

(a) No, unless an economic reason emerged which necessitates a change.

(b) The system voltage has been selected as +/- 200 kV based on a number of factors, including the lower installed cost of transmission lines, cables and ac/dc converters, the lower total life-cycle cost of the system at this voltage, and the increased confidence in deployment of VSC converter technology at this voltage level. Selection of MI cable technology would not change any of these decision factors, and only a change in the economics would cause NSPML to reconsider the system voltage.

NON-CONFIDENTIAL

Request IR-151:

With reference to Appendix 3.01, page 17, please provide calculations showing:

(a) the annual incremental cost associated with the higher electrical losses for the +/- 200 kV system vs. a more efficient +/- 250 kV system, and

(b) the breakeven year of operation to fully offset the higher initial construction cost of the +/- 250 kV system as compared to a less expensive +/- 200 kV system.

Response IR-151:

(a) Based on the same loss costs, capacity factors and financial parameters used in the conductor optimization study, the incremental losses for a +/- 200-kV system voltage over a +/- 250-kV system voltage have been estimated at between $0.57 M and $1.42 M per year. The reason for the range of values is that two different conductor sizes have been considered for the +/- 250-kV system, and two different costs of energy have been used to evaluate the loss differential. The results are summarized in the table below:

Differential of Annual Loss					
Conductor	**+/- 200 kV HVdc**	**+/- 250 kV HVdc**	**[250 kV vs 200 kV]**		
				@$50/MHh Energy cost	**@$70/MHh Energy cost**
	MWh	MWh	MHh	$M	$M
Smaller conductor		61,995	11,414	0.57	0.80
1xACSR Bluebird	73,409	53,162	20,247	1.01	1.42

Only a single conductor was considered for the +/- 200-kV system voltage, because the Bluebird conductor was selected as part of the conductor optimization study, but no conductor optimization has been undertaken for the +/- 250-kV system voltage. The range of loss costs corresponds to the low and high bounds on the energy loss costs used in the stress tests for the conductor optimization study. Retaining the Bluebird conductor in a +/-250-kV system development, the annual loss savings compared to the +/- 200-kV system option range from $1.01 M ($50/MWh loss cost) to $1.42 M ($70/MWh loss cost). With the +/250-kV system conductor reduced to the next smaller size, the annual loss savings fall to the range of $0.57 M to $0.80 M.

(b) On a present value basis, the loss savings due to the higher voltage do not offset the higher initial construction costs over the life of the project. For the two conductor sizes considered for the +/- 250-kV option, and over the full range of loss costs considered, the +/- 200-kV system voltage is preferred from a Net Present Value perspective. The margin is narrow in the case of high loss costs, and quite wide in the case of low loss costs.

NON-CONFIDENTIAL

Request IR-152:

With reference to Appendix 3.01, page 18, please provide a complete list of HVDC projects featuring the VSC technology planned for commissioning in the period from 2013 to 2015 worldwide and specify the capacity, the polar configuration, and the level of voltage for each project. Indicate the land-based and sub-sea lengths for each project.

Response IR-152:

An updated version of Figure 3-6 in the Application is provided below.

2013	Borwin2, Germany, Siemens (+/- 300 kV, 800 MW) Dolwin1, Germany, ABB (+/-320 kV, 800 MW, 75/90 km of sea/land polymer cables) Helwin1, Germany, Siemens (250 kV mono, 576 MW, 85 km polymer cable)
2014	Mackinac, USA, ABB (70 kV, 200 MW, back to back) Skaggerak4, Norway-Denmark, ABB (400 kV mono, 700 MW, 140 km Mass Impreg. cable) SouthWest Link, Sweden-Norway, Alstom (+/- 300 kV, 1440 MW, 192 km of land polymer cable) Sylwin1, Germany, Siemens (320 kV, 864 MW, 160/45 km sea/land polymer cables) INELFE 1&2, France-Spain, Siemens (+/- 320 kV, 1000 MW each, 65 km land polymer cables)
2015	Troll 3&4, Norway, ABB (+/- 66 kV, 100 MW each, 70 km subsea polymer cables) Helwin2, Germany, Siemens (+/- 320 kV, 690 MW, 85/25 km of sea/land polymer cables) BorWin2, Germany, Siemens (+/- 300 kV, 800 MW, 125/75 sea/land polymer, 114 km OH line) Dolwin2, Germany, ABB (+/- 320 kV, 900 MW, 45/90 km of sea/land polymer cables) Finland-Aland, TBD, (+/- 80 kV, 100 MW, 100 km) Nordbalt, Sweden-Lithuania, ABB (+/- 300 kV, 700 MW, 400/50 km of sea/land polymer cables)

NON-CONFIDENTIAL

Request IR-153:

With reference to Appendix 3.01, page 18, please provide all the studies undertaken by NSPML, in consultation with NLH and NSPI, relied on in making a decision to choose the +/- 200 kV operating voltage for the Maritime Link Project.

Response IR-153:

No formally documented study reports have been prepared, and the investigations were undertaken by Nalcor based on preliminary engineering and cost estimates, and preliminary comparisons of construction costs and loss costs for the two system voltages. Please see the response to SBA IR-151.

NON-CONFIDENTIAL

Request IR-154:

With reference to Appendix 3.01, page 23, please provide an estimated cost comparison between the added costs for the overhead HVDC construction in the cape Breton Highlands peninsula area versus the added cost for the extension of the submarine cable route to Point Aconi.

Response IR-154:

Consideration was given to cable landing sites in the Wreck Cove area, as well as to sites north of this location. For the Wreck Cove location, it may have been possible to shorten the submarine cable route length by about 20 km compared to the Point Aconi landing site, but the overland HVdc line route to Port Hastings would have been double the length of the Point Aconi to Woodbine route. Subsea cable average cost for the cable and installation only (excluding common elements which would be the same in any landing location) is roughly a $30 million saving, with the overhead route being about 2.5 times the route length to Point Aconi, approximately an additional $90 million before adjusting for the route complexity. The line route from Wreck Cove to Port Hastings is considered more complex and costly on a per kilometer basis than the route from Point Aconi to Woodbine. Other technical upgrades and interfaces at the substations are comparable in cost for the purpose of this evaluation. A similar cost differential is applicable to route the overhead transmission from Wreck Cove to Woodbine as to Port Hastings. An AC build between Wreck Cove and Port Hastings was also considered; however, a single 345-kV line was technically inadequate and uneconomic. Also, the Woodbine route continues to utilize existing ac transmission rights of way into the future, which would otherwise be under-utilized as coal generation is reduced for GHG compliance reasons.

Request IR-155:

With reference to Appendix 3.01, page 23, please explain the criteria for identifying Lingan as one of the alternative cable landing sites in Cape Breton.

Response IR-155:

Sites East and West of Sydney Harbor were considered because of proximity to existing line routes to Woodbine. Routing alongside existing infrastructure is important to minimize the footprint of the transmission corridor. Sites East of Sydney Harbour, including Lingan, offered the possibility of a shorter overhead line route to Woodbine, but a somewhat longer submarine cable route.

NON-CONFIDENTIAL

Request IR-156:

With reference to Appendix 3.01, page 24, please describe in detail the three cable burial techniques: trenching, horizontal directional drilling (HDD), and micro-tunneling.

Response IR-156:

HDD is a steerable trenchless method of installing underground pipes, conduits and cables in a shallow arc along a prescribed bore path by using a surface-launched drilling rig, with minimal impact on the surrounding area. Directional boring is used when trenching or excavating is not practical.

Micro-tunnelling refers to a tunnel that is constructed using a remote-controlled, guided tunnelling machine (meaning that personnel entry is not required), with continuous pressure on the face of the excavation. A micro-tunneled pipeline or conduit is constructed by consecutively pushing pipes using a jacking system, with the spoil continuously excavated and removed. The micro-tunnel is constructed between two excavated shafts at either end of the tunnel; a launch shaft and a reception shaft.

Trenching is creating an artificial long and narrow depression with steep sides on the seafloor.

NON-CONFIDENTIAL

Request IR-157:

With reference to Appendix 3.01, page 24, please identify any limitations; including construction window permit limits and other regulatory requirements and restrictions that may affect scheduling of the cable burying under each of the three burial techniques.

Response IR-157:

Permits required for cable burying are identified in the EA documents, and will be obtained well in advance of the offshore burial campaign.

NON-CONFIDENTIAL

Request IR-158:

With reference to Appendix 3.01, page 24, please explain why under the trenching option weather poses a risk to activity and schedule while under the HDD and the micro-tunneling options it does not.

Response IR-158:

HDD will be constructed using a drill rig from onshore, therefore sea-states and marine weather does not affect it.

The majority of micro-tunneling activities will be performed from onshore, and is therefore not affected by marine weather. The only offshore activity required is construction of the reception shaft and might be affected by weather.

Trenching is performed using a vessel or barge offshore, and all operation is therefore affected by weather, sea-states and currents. On land trenching is susceptible to weather for obvious reasons.

NON-CONFIDENTIAL

Request IR-159:

With reference to Appendix 3.01, page 24, please provide the cost estimates for all three cable burial technique options.

Response IR-159:

Cost estimates are available in the documents listed below. Please refer to SBA IR-12.

(i) HDD Feasibility Study (AMEC)

(ii) Cabot Strait Trenched Landfalls Feasibility Study (Boskalis)

NON-CONFIDENTIAL

Request IR-160:

With reference to Appendix 3.01, page 24, please explain the nature of the higher execution risk associated with the micro-tunneling.

Response IR-160:

Micro-tunneling construction method would have to include either a reception shaft constructed offshore using steel sheet pile walls or an underwater pit for retrieval of the micro-tunneling machine (along with associated procedures, personnel and equipment for underwater cutting head retrieval at the exit location). All these activities will increase the cost, and will be affected by potential weather delays.

In addition to that, when multiple cables are installed through micro-tunnels, they are generally bundled and installed in a single pull. As a result, access to individual cables for recovery and repair purposes results in taking all cables out of service. Separate tunnels for each cable are not economically feasible given the cost of excavating shafts required for each tunnel.

NON-CONFIDENTIAL

Request IR-161:

With reference to Appendix 3.01, page 25, would the third 230 kV line from Granite Canal into Bottom Brook Substation in Newfoundland be required to ensure reliable delivery of the minimum 170 MW only to the province of Nova Scotia?

Response IR-161:

The option of building the system only to provide reliable delivery of the 170 MW for the province of Nova Scotia was not studied, as this option was not consistent with the agreements reached with Nalcor.

NON-CONFIDENTIAL

Request IR-162:

With reference to Appendix 3.01, page 25, is it the NSPML position that the ratepayers in Nova Scotia should pay a share of the Newfoundland system reinforcement projects identified as required for reliable delivery of as much as 500 MW (including the prospective wheeling requirements) through the Maritime Link?

Response IR-162:

The reliable delivery of up to 500 MW of power through the Maritime Link provides benefits to the ratepayers of Nova Scotia. This delivery provides the opportunity for Nova Scotians to enjoy the benefits of a minimum of 170 MW of reliable and low-cost renewable power, and through the supplementary block (in the first five years) or economy purchases, additional amounts of clean and reliable power will be available to Nova Scotia. Please refer to Liberal IR-11.

NON-CONFIDENTIAL

Request IR-163:

With reference to Appendix 3.01, page 25, please identify the estimated costs of the system reinforcement projects on a project-by-project basis.

Response IR-163:

There is no mention of system reinforcements at the reference provided. There is reference to NS Power upgrades on the 25th page of Appendix 3.01, on the basis of which the following response is given:

Network Upgrade	Estimated Cost
L-6513 Rebuild / Upgrade Line Terminals	$10,100,000
Strait Crossing / Separate L-8004 / L-7005	$10,800,000
L-6511 / L-6515 / L-6552 Upgrades	$16,600,000

NON-CONFIDENTIAL

Request IR-164:

With reference to Appendix 3.01, page 35, please explain the meaning of "a return period of 1000 years between externally caused failures of either one of the two poles in the cablesystem."

Response IR-164:

A return period is an estimate of the likelihood of an event. It is a statistical measurement typically based on historical data and is usually used for risk analysis. In the Maritime link case, it is the probability of having one damage event in 1000 years.

NON-CONFIDENTIAL

Request IR-165:

With reference to Appendix 3.01, page 41, please provide the basis for the expectation that a pole outage will "occur for a short duration, expected to be between 40-120 hours per year for the Maritime Link project."

Response IR-165:

The estimate was based on a target value of 5 pole outages per year for the system per NSPML specifications, and estimated average pole outage duration of 37 hours per CIGRE documents, and an assumption that 50 percent of these hours will be spent in monopolar/earth return mode. This established 92 hours as a target value which is expected to be at the high end of actual project experience. The range from 40 hours to 120 hours was adopted in anticipation that the average frequency of pole outages would likely be lower than the target value, assumed to be 80 hours, and that the low and high range would be 50 percent lower and higher than this value.

Typical industry experience is likely to remain fairly stable as far as overhead HVdc transmission performance, but the average industry performance of ac/dc converters is likely to improve as large numbers of new DC projects come into service and begin to outnumber the large number of projects older than 30 years.

NON-CONFIDENTIAL

Request IR-166:

With reference to Appendix 3.01, page 41, are the earth return and the shore grounding systems designed to sustain safe and reliable operation of the Maritime Link at the 250 MW capacity level when the pole outage duration exceeds the expected maximum of 120 hours? What are the risks involved?

Response IR-166:

Yes, the earth return system and the shore grounding sites are being designed to sustain continuous safe and reliable operation of the Maritime Link at the 250 MW capacity level. The safety and reliability of the system will not be compromised if the pole outage duration exceeds the target of 120 hours. Only the secondary impacts of the earth return system are limited by the 120 hour target. Specifically, the dc current injection into the earth and associated Ground Potential Rise result in corrosion to metallic infrastructure immersed in the soil in the vicinity of the grounding site, the amount of corrosion is a function of the ampere-hours of operation. Risks to local metallic infrastructure, associated with actual ampere-hours exceeding the design ampere-hour duties over the life cycle of the project, would need to be mitigated.

NON-CONFIDENTIAL

Request IR-167:

With reference to Appendix 3.01, page 41, would repairs of a failed pole never require de-energizing of the healthy pole? If not, please identify the failure scenarios when the Maritime Link would have to be completely taken out of service.

Response IR-167:

The Maritime Link converter stations will be specified and designed to ensure that no single failure event, or its corresponding repair activities, would cause both poles to be out of service. The system design will ensure that only second-order failure events would result in both poles being taken out of service. Second order failure events would include an equipment failure on one pole while the other pole was out of service for maintenance, or consecutive equipment failures on two poles before repair can be completed on the first failure, or simultaneous pole failures due to different causes. On the overhead HVdc transmission line segments, designs will be completed which address the localized climatic challenges and the experience for each line segment given that the HVdc lines will be routed in parallel to existing HVac lines. In the unlikely event of the collapse of a support structure, this would cause both poles to be interrupted until repairs could be completed. Similarly, if routing constraints require some sections of the submarine cable to be co-located or “bundled,” common-mode failure scenarios may exist where a single event damages both cables. Significant design, testing and installation quality assurance is undertaken to reduce the likelihood of such an event.

NON-CONFIDENTIAL

Request IR-168:

With reference to Appendix 3.01, page 41, will Nova Scotia continue to receive deliveries of the Nova Scotia Block during the period of time when one pole of the Maritime Link is out of service for whatever reason?

Response IR-168:

Yes, the Maritime Link is designed to carry 500MW of which 250MW is firm as one of the two cables can experience a failure and 250MW can continue to flow into Nova Scotia. As the path to deliver the Nova Scotia Block is firm from from source to the delivery point, the loss of one pole will not effect the flow of the NS Block.

NON-CONFIDENTIAL

Request IR-169:

With reference to Appendix 3.01, pages 51 and 53, would the new 230 kV line between Granite Canal and Bottom Brook and/or the expansion and reconfiguration of the respective existing substations and switchyards be required to meet the needs of the Newfoundland system absent construction of the Maritime Link at any time over the 35-year period from 2017?

Response IR-169:

There is no need for the Granite Canal to Bottom Brook reinforcement over any reasonable planning horizon, in the absence of the Maritime Link Project.

NON-CONFIDENTIAL

Request IR-170:

With reference to Appendix 3.01, pages 55 and 25, please explain the rationale for installation of a second 345/230 transformer at Woodbine substation.

Response IR-170:

The rationale for installing a second 345 kV / 230 kV transformer at Woodbine is based on reliability requirements for the Maritime Link. Should the existing transformer fail, the transformer would either require replacement or shipment to a repair facility, either of which would take 12 months or longer. Without the transformer in service, the operation of the Maritime Link would be significantly restricted for the duration that the transformer is not in service. Transformers of this size are not designed to be interchangeable, so finding a temporary replacement is not a viable option. The installation of the second transformer allows for reliable operation of the Maritime Link in the event of a long duration transformer failure event.

NON-CONFIDENTIAL

Request IR-171:

With reference to Appendix 3.01, pages 55 and 25, please explain the need for construction of two additional 230 kV transmission lines interconnected to Woodbine substation.

Response IR-171:

Two additional 230 kV lines will not be constructed. Two existing 230 kV transmission lines, L-7011 and L-7012 currently pass by the Woodbine Substation (within 300 m) but do not terminate at the substation. The scope of work required is to connect these existing 230 kV lines into the 230 kV bus at Woodbine. The reason for doing this is to address 230 kV system overloads for the contingency loss of the 345 kV line L-8004.

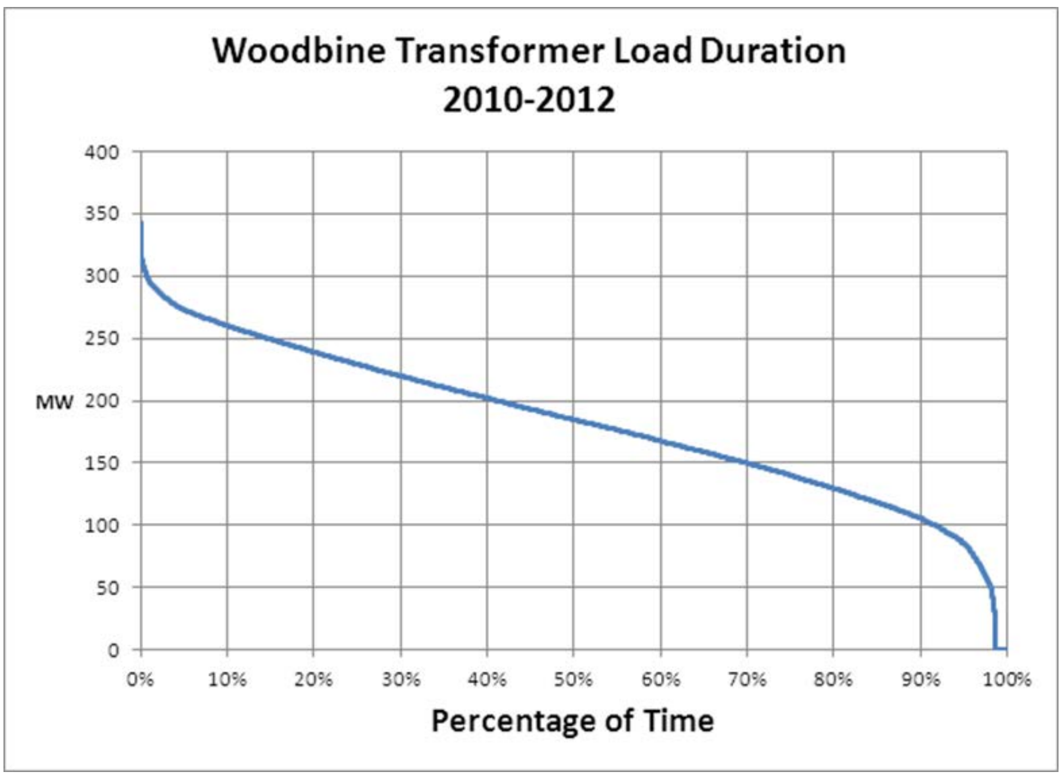
NON-CONFIDENTIAL

Request IR-172:

With reference to Appendix 3.01, page 55, please provide the current loading data on the Woodbine substation and explain why up to 500 MW of additional power flows through the Maritime Link would require doubling the connection capacity at Woodbine substation.

Response IR-172:

A load duration curve for the existing Woodbine 345 kV-230 kV is provided below for the three period from 2010-2012. See also response to CA/SBA IR-170.



NON-CONFIDENTIAL

Request IR-173:

With reference to Appendix 3.01, page 58, please explain how in the process of the conductor type and size selection the market value of electric energy in 2017 was derived at $64/MWh. Does this figure represent an average price, on peak, or off peak? Provide all work papers supporting this calculation.

Response IR-173:

The $64/MWh figure presented in Appendix 3.01 was a dated figure, and the conductor optimization study was conducted using a base figure of $60/MWh, with sensitivity studies conducted down to $50/MWh and up to $70/MWh.

Losses were calculated for each conductor size considered, within each of a number of discrete time intervals during a 5-month “high flow” period and a 7-month “low flow” interval, and energy loss values were calculated based on the peak load losses. The cost of losses was computed using the low, medium and high loss costs.

NON-CONFIDENTIAL

Request IR-174:

With reference to Appendix 3.01, page 58, please explain how the average loading was derived at 316 MW and 790 Amperes per pole.

Response IR-174:

The average loading was derived as 316 MW using the methodology presented in NSUARB IR-13.

NON-CONFIDENTIAL

Request IR-175:

With reference to Appendix 3.01, page 58, please provide the conductor optimization study carried out by Hatch for the overland HVDC transmission line.

Response IR-175:

The requested study is provided in Attachment 1.

HATCH™

Emera Newfoundland and Labrador (ENL)
Maritime Link Project

Conductor Optimization for HVdc Transmission Line

Prepared by: June 21, 2012

Adeel Afzal Date

APPROVALS

Hatch

Approved by: June 21, 2012

Iftikhar Khan Date

Emera Newfoundland and Labrador (ENL)

Approved by: B - Approved for design stage DB July 30th 2012

Date

Project Report

June 21, 2012

Emera Newfoundland and Labrador (ENL)
Maritime Link Project

DISTRIBUTION

Don Berringer – ENL
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Steve Coates - ENL

Conductor Optimization for HVdc Transmission Line

Table of Contents

1. Introduction

Emera Newfoundland and Labrador (ENL) is proposing to develop the Maritime Link Transmission Project between the Island of Newfoundland and Cape Breton, Nova Scotia. The Maritime Link is a new 500 MW +/-200 kV HVdc transmission system that includes the following components.

- Overhead Transmission lines (ac, HVdc);
- Subsea cables;
- Grounding sites associated with Converter stations and associated grounding lines;
- Two ac/dc converter stations and adjoining ac substations, plus expansion of a third ac substation;
- Three OH/UG transition compounds;
- Other potential infrastructure.

The high voltage Overhead Transmission Line components of the Project include:

- A new 136-km long +/- 200 kV HVdc transmission line between Cape Ray and Bottom Brook In south-western Newfoundland, along an existing transmission corridor.
- A new 160-km long 230 kV ac transmission line between Bottom Brook and Granite Canal in a combination of existing and new corridors.
- A new 45-km long +/- 200 kV HVdc transmission line between Point Aconi and Woodbine station in Nova Scotia, parallel to the existing transmission corridor.

Hatch has been mandated by ENL to carry out Conceptual Basis of Design (CBoD) and Functional Basis of Design (FBoD) studies for a number of project components; including the transmission lines. As part of the current project phase (FBoD), Hatch is required to recommend the conductor size to be utilized on the HVdc transmission line.

2. Scope

This report provides a comparison for various conductor types for use on the Maritime Link HVdc transmission lines and makes recommendation for the conductor type to be utilized on the project.

The comparison is carried out for various conductor types, to cover a range of sizes as follows;

1- Single ACSR 2156 Bluebird per pole (Base case considered in CBoD design)

2- Single ACSR 2515 Joree per pole

3- Twin ACSR 1112 Beaumont per pole

The conductor being considered[1] for the HVdc transmission line was AASC/ASC 2000 MCM Cowslip at the time of commencement of Hatch services. This 44mm diameter conductor is an Aluminium only conductor and does not include Aluminium alloy or Steel reinforcement strands. As such, this conductor is not expected to perform well in heavy ice conditions expected in the project areas. Hatch created a PLS-CADD model of a typical span using ASC Cowslip and observed that the corresponding sag is large in both thermal and ice loading conditions. The corresponding structure heights would be significantly large and therefore not economical.

The electrical studies for the above conductor types (except Twin ACSR Beaumont which was brought into consideration at a later stage) had been carried out earlier[2] and the conductors were found to perform satisfactorily. The study also identified the thermal and corona losses associated with the conductor types. The losses for ACSR Beaumont were subsequently determined and have been considered in the comparison included in this report.

3. Conductor Data

The data for the conductor types selected for evaluation is given in the following table;

Table 1 Conductor Properties

Description	Unit	Conductor Type		
		ACSR Bluebird	ACSR Joree	ACSR Beaumont
Outside diameter	mm	44.75	47.75	31.70
Steel core diameter	mm	12.19	10.8	6.89
Stranding		84/19	76/19	42/7
Aluminium area	mm^2	1092.3	1274.2	564.0
DC Resistance at 20^{o}C	Ohm/km	0.02628	0.02264	0.051
Conductor mass	kg/km	3723	4071	1785
Rated strength	kN	281.7	291.5	126.1

[1] RBJ document 'Mini-Specification for Budgetary Pricing of Converter Stations' No.162-20100-1 Rev-1 dated January 15, 2012
[2] Hatch document 'HVdc Conductor Selection and Electrical Design Studies' No.H340528-1000-70-124-0002 Rev-3 dated May 24, 2012

4. Comparison

The comparison between the conductors is based on the following factors;

- Cost (capital and line losses)
- Structure geometry and conductor mechanical loading
- Right-of-way width
- Manufacturing

4.1 Cost

4.1.1 Capital Cost

The variation in the capital cost of the transmission line with different conductor types is due to the following factors (supply and installation);

- Conductor
- Tower weights and heights
- Foundation sizes
- Conductor accessories

The capital costs for the transmission lines (Newfoundland and Nova Scotia sections) with the above conductor options are as follows;

- 1xACSR Bluebird $217.1 M
- 1xACSR Joree $222.3 M
- 2xACSR Beaumont $263.0 M

The costs for ACSR Bluebird and ACSR Joree options are very similar. The cost for ACSR Beaumont option is comparatively on the high side. This is due to large sag (and correspondingly higher towers) for this option. Additionally, stringing cost for twin smaller conductors is higher than that of a single larger conductor.

4.1.2 Line Losses

ENL has advised the following average line loading assumption;

- 1 TWh equal over 12 months, plus 2 TWh equal over April to October

The line capacity is 500 MW. A total of 3 TWh over 7-months would exceed this capacity. We have therefore assumed that the average line loading over the 12-months period is as follows; November-March (1 TWh) and April-October (2 TWh).

The corresponding power flow is given in the following table.

Table 2 Power Flow

Period		Total energy	Average MW	Average Ampacity
5 months	3,624 hrs	1 TWh	275.94 MW	689.85 A per pole
7 months	5,136 hrs	2 TWh	389.41 MW	973.52 A per pole

Thermal losses are a function of 'square of line ampacity'. It is generally recommended that thermal losses are calculated at different times based upon line loading variation. In the absence of information regarding line loading variation, the thermal losses are based upon average line current, as given in the following table (coronal loss are fixed and do not vary with current);

Table 3 Line Losses

Conductor	Thermal Loss per pole (MW)			Line Corona loss	Annual Line Loss (MWh)
	full load[3]	5-month	7-month	12-month	
	1,250 A	685 A	980 A	MW	
1xACSR Bluebird	15.7	4.8	9.6	0.78	73,409
1xACSR Joree	13.3	4.1	8.1	0.78	63,189
2xACSR Beaumont	14.7	4.5	8.9	0.77	68,649

4.1.3 *Cost Comparison*

The following variables have been considered for the calculation of costs, as advised by ENL;

- Market value of energy $ 60/MWh in Year-2017 (stress test at -$10 and +$10)
- Escalation value 2% per year (stress test at -1.5% and +4%)
- Cost of capital 6% per year

The line losses have been calculated over a 50-year period starting in Year-2017. The NPV of all costs have been converted for the Year-2012. These costs and the various stress tests are given in the following table;

[3] Hatch document 'HVdc Conductor Selection and Electrical Design Studies' No.H340528-1000-70-124-0002 Rev-3 dated May 24, 2012

Table 4 Cost Comparison

Conductor Type	Annual Line Loss	Energy Value (Year-2017)	Annual Escalation Value	Annual Cost of Capital	NPV of Energy Loss Year-2017	Direct Capital Cost Year-2012	Total NPV of Cost Year-2012	Variation (from Bluebird)	
	MWh	$/MHh	%	%	50-yrs	$M	$M	$M	%
1xACSR Bluebird	73,409	50	1.5%	6.0%	$ 72.5	$ 217.1	$268.2	$ -	0%
			2.0%	6.0%	$ 78.8		$272.7	$ -	0%
			4.0%	6.0%	$ 115.3		$298.4	$ -	0%
		60	1.5%	6.0%	$ 87.0		$278.4	$ -	0%
			2.0%	6.0%	$ 94.6		$283.8	$ -	0%
			4.0%	6.0%	$ 138.4		$314.7	$ -	0%
		70	1.5%	6.0%	$ 101.5		$288.7	$ -	0%
			2.0%	6.0%	$ 110.4		$294.9	$ -	0%
			4.0%	6.0%	$ 161.5		$331.0	$ -	0%
1xACSR Joree	63,189	50	1.5%	6.0%	$ 62.4	$ 222.3	$266.3	$ (1.92)	-1%
			2.0%	6.0%	$ 67.9		$270.2	$ (2.48)	-1%
			4.0%	6.0%	$ 99.3		$292.3	$ (6.08)	-2%
		60	1.5%	6.0%	$ 74.9		$275.1	$ (3.33)	-1%
			2.0%	6.0%	$ 81.4		$279.7	$ (4.11)	-1%
			4.0%	6.0%	$ 119.1		$306.3	$ (8.41)	-3%
		70	1.5%	6.0%	$ 87.4		$283.9	$ (4.74)	-2%
			2.0%	6.0%	$ 95.0		$289.3	$ (5.66)	-2%
			4.0%	6.0%	$ 139.0		$320.3	$ (10.66)	-3%
2xACSR Beaumont	68,649	50	1.5%	6.0%	$ 67.8	$ 264.1	$311.9	$ 43.69	16%
			2.0%	6.0%	$ 73.7		$316.1	$ 43.40	16%
			4.0%	6.0%	$ 107.9		$340.2	$ 41.78	14%
		60	1.5%	6.0%	$ 81.4		$321.5	$ 43.05	15%
			2.0%	6.0%	$ 88.5		$326.5	$ 42.70	15%
			4.0%	6.0%	$ 129.4		$355.3	$ 40.66	13%
		70	1.5%	6.0%	$ 95.0		$331.1	$ 42.42	15%
			2.0%	6.0%	$ 103.2		$336.9	$ 41.92	14%
			4.0%	6.0%	$ 151.0		$370.5	$ 39.60	12%

The color shades in the above table are simply to group similar numbers within each column. Green shades indicate smaller numbers group, Yellow shades indicate higher numbers group and red shades indicate highest numbers group.

The last two columns provide the comparison with base case (single ACSR Bluebird option) for each of the corresponding variation of various factors.

The ACSR Bluebird and ACSR Joree options provide similar costs, and therefore can be treated as same for the purpose of this evaluation and given the above parameters.

The ACSR Beaumont option indicates higher costs.

4.2 Structure Geometry and Conductor Mechanical Loading

4.2.1 Structure height

For the same limitations of conductor loading, ACSR Beaumont indicates significantly larger sag than the other conductor types, which would result in higher structures.

The sag for ACSR Beaumont could be reduced by increasing the tension limits, but that is not advisable.

The structure heights between ACSR Bluebird and ACSR Joree would be similar.

4.2.2 Cross-arm width

Due to larger sag for ACSR Beaumont (as explained above), the insulator swing is larger (as compared to ACSR Bluebird and ACSR Joree options) for the same wind and temperature conditions. This would increase the cross-arm width for ACSR Beaumont option.

The cross-arm width between ACSR Bluebird and ACSR Joree options would be similar.

4.3 Right-of-way width

Due to larger sag for ACSR Beaumont (as explained above), the conductor blow-out is wider which would result in increase right-of-way width requirements for ACSR Beaumont option.

The cross-arm width between ACSR Bluebird and ACSR Joree options would be similar.

4.4 Manufacturing

There seems to be some reluctance from manufacturers in quoting for ACSR Joree conductor, in that M/s Nexans did not provide its quote.

We did not face any issue in receiving budgetary quotes for ACSR Bluebird or ACSR Beaumont conductors.

5. Recommendation

The ranking between various conductor options, as discussed above is given in the following table;

Table 5 Ranking of Conductor Options

Factor	Single ACSR Bluebird	Single ACSR Joree	Twin ACSR Beaumont
Cost	1st	1st	3rd
Tower geometry	1st	1st	3rd
Right-of-way width	1st	1st	3rd
Manufacturing	1st	3rd	1st

Based upon the factor considered in this report, single ACSR Bluebird is the recommended conductor option to be considered in the FBoD stage.

NON-CONFIDENTIAL

Request IR-176:

With reference to Appendix 3.01, page 58, please provide the comparative analysis performed by Hatch for various structure types for the HVDC transmission line.

Response IR-176:

Please refer to Attachment 1.

HATCH™

Recommendation of Structure Types for HVdc Transmission Line

(MLP ER Structure Recommendation rev 4)

B - Approved For Design Phase
SC - April 30th 2012

2012-04-26	4	Final	MR/FL	AA	IK/MG	
2012-04-24	3	Final	MR/FL	AA	IK/MG	
2012-03-21	2	Final	MR/FL	AA	IK/MG	
2012-03-05	1	Draft	MR/FL	AA	IK/MG	
DATE	**REV.**	**STATUS**	**PREPARED BY**	**CHECKED BY**	**APPROVED BY**	**APPROVED BY**
HATCH						**CLIENT**

Table of Contents

1. Introduction

Emera Newfoundland and Labrador (ENL) is proposing to develop the Maritime Link Transmission Project between the Island of Newfoundland and Cape Breton, Nova Scotia. The Maritime Link is a new 500 MW +/-200 kV HVdc transmission system that includes the following components.

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The high voltage Overhead Transmission Line components of the Project include:

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Hatch has been mandated by ENL to carry out Conceptual Basis of Design (CBoD) and Functional Basis of Design (FBoD) studies for a number of project components; including the transmission lines. As part of the services during the CBoD phase, Hatch is required to recommend the structure type(s) to be utilized for the HVdc transmission line.

This report has been prepared to evaluate different structure types and to recommend the structure type(s) for the project. ENL comments were received on Rev-1 and Rev-2 of this report and these are incorporated in this revised report.

2. Scope

This document describes the process applied for the recommendation of the structure type to be used for the +/-200 kV HVdc transmission line, the factors considered and their relative weightings.

The comparison is made between the following structure types:

- Self-supporting lattice steel towers;

- Guyed lattice steel towers;
- H-frame wood pole structures;
- H-frame wood-equivalent steel pole structures;
- Single wood pole structures;
- Single steel pole structures.

A brief review of some of the other structure materials (composite poles and laminated wood poles) has also been carried out. The comparison has been made for Tangent structures only. The heavy-angle, dead-end and river-crossing structures are assumed to be self-supporting lattice towers and therefore do not impact the choice of Tangent structures.

As is typical during the conceptual design stage of a project, the comparison of different structures has been based upon preliminary design parameters. The design parameters will be reviewed and finalized and applied for the design of selected structure type as the project progresses.

3. Structure Types

3.1 Self-support Lattice Steel Tower

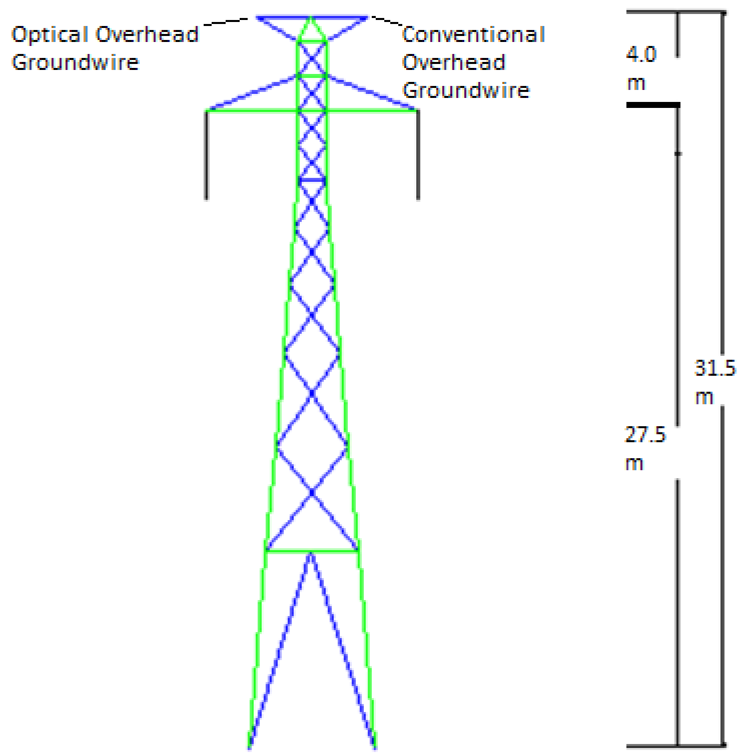

Figure 1 Self-support Lattice Steel Tower

A preliminary PLS-Tower model has been prepared for the tangent structure using a ruling span of 350 m. The approximate calculated weight for a typical tangent tower is 6.3 mt. Steel towers can be procured locally and from international manufacturers and budgetary prices were obtained from both sources. The budgetary costs from local suppliers are in the range of $ 3,000 per mt and from international suppliers in the range of $ 2,000 per mt. Both figures have been used in the evaluation as discussed in Section 4 below.

3.2 Guyed Lattice Steel Tower

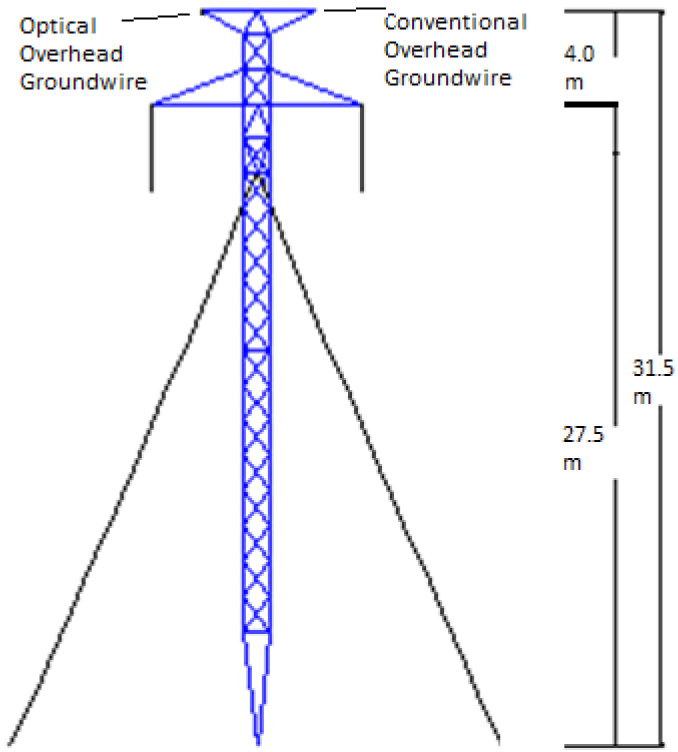

Figure 2 Guyed Lattice Steel Tower

A preliminary PLS-Tower model has been prepared for the tangent structure using a ruling span of 350 m. The approximate calculated weight for a typical tangent tower is 3.6 mt. The pricing strategy is similar to that of lattice steel towers. It is to be noted that sometimes guyed towers are slightly more expensive as compared to self-support towers (on a per mt base) due to relatively higher number of drills that are required. For this reason, the unit cost per mt was assumed 5% higher than that of self-supporting towers.

3.3 H-framed Wood Pole Structures

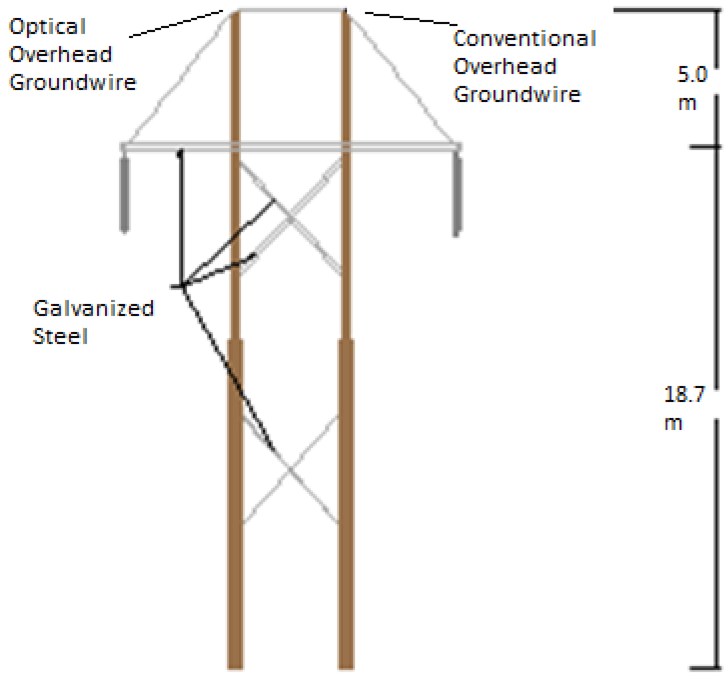

Figure 3 H-Framed Wood or Wood-equivalent Steel Structures

A PLS-Pole model has been prepared for the H-framed structure and determined that the typical pole would be 85'/Class-1. The corresponding span length would be 170 m. The H-frame would require double bracing. The bracing and the cross-arms were considered to be galvanized steel. Side-guys would be required in bog conditions for lateral support. The H-framed structures would require two shield-wires.

Prices have been obtained for full-length treated Western Red Cedar (WRC) and Douglas Fir (DF) type poles. Hatch also explored the application of Southern Yellow Pine (SYP) and consulted with a supplier. The feedback from the industry is that application of SYP for 60' and longer sizes has resulted in some project issues. There have been issues with availability of these poles and the physical characteristics of the poles (shape, straightness, large knot whorls, twists) have been a concern. SYP has therefore not been considered.

3.4 H-framed Wood-equivalent Steel Pole Structures

These structures are similar to H-framed Wood pole structures except that the poles are galvanized steel. This type has been considered due to relatively attractive steel pricing. Budgetary prices were obtained for base-plated galvanized steel poles, which are around 5% more expensive than the equivalent wood poles. For the purpose of this comparison, steel poles were assumed 10% more costly than wood poles, to account for step bolts, jacking nuts and similar items. The poles would be direct buried in ground and coated at the ground-line to avoid biological ingress.

3.5 Single Wood Pole Structures

A PLS-Pole model has been prepared for the Single pole structure and determined that the typical pole would be 80'/Class-H2. The corresponding span length would be 80 m.

3.6 Single Steel Pole Structures

The same comparison applies as between Wood and Steel H-frames.

3.7 Composite Poles

Composite or Fiber Reinforced Plastic (FRP) is a relatively new pole material as compared to Wood and Steel poles. Composite poles are generally more acceptable for temporary construction (e.g. by-pass lines) or relatively short lines. Their very low weight and modular design also makes them a real option for lines in very rugged terrain or where material storage space is critical.

There have been concerns regarding performance and constructability of Composite poles with respect to UV radiation, frost/thaw cycles, hardware attachments and field-drilling. Most of these issues have been addressed by some of the major manufacturers, but their long-term field experience has not been established. Hatch does not recommend the application of Composite poles for such a long and critical line.

3.8 Laminated-wood Poles

Hatch does not recommend the application of Laminated-wood poles for this line, based upon similar principles as that for Composite poles. The related concerns (which may have been resolved to certain extent) have been field-drilling and loosening of lamination.

4. Basis of Comparison

The various influencing factors considered in the comparative evaluation of the different structure types described above are given in this section.

4.1 Cost

The unit material prices have been based on in-house data, budgetary quote(s) and experience of Hatch staff. The prices are for comparative purposes only. The comparisons are made only for items influencing the structure types. Common costs (e.g. conductor) are not included in this comparison.

The following material prices have been considered in the preparation of this comparison;

- Tower steel (local) $ 3,000 per mt
- Tower steel (international) $ 2,000 per mt (compared separately)
- Wood poles $ 6,000 to $7,000 per pole
- Wood-equivalent steel poles $6,600 to $7,700 per pole
- Insulator strings $1,800 per string

Similarly, construction prices are compared for individual cases as follows:

Foundation costs

Foundation costs have been estimated separately for Normal soil / Till, Rock and Bog conditions. The anticipated percentages that have been assumed for Normal/Rock/Bog are 68/20/12 in Newfoundland and 82/4/14 in Nova Scotia. These estimates are based on the review of the following documents and adjusting as appropriate for conflicting information;

1. Government of Newfoundland and Labrador, Department of Mines and Energy, Geological Survey Branch; Surficial Geology, Maps 93-80, 94-234 and 94-236.
2. Digital Wetland Mapping provided by Nova Scotia Geomatics Center (NSGC), Nova Scotia Topographic Database (NSTDB).
3. Newfoundland and Labrador Power Commission (1967), Bay D'Espoir Development, 138 kV T.L. No.214 Plan and Profile, Sheets 1 to 50.
4. Nova Scotia Department of Natural Resources, Mines and Energy Branches (1992), Surficial Geology, Map 92-3.
5. Digital Wetland Mapping for Newfoundland provided by National Topographic Database.
6. Nova Scotia Power Corporation (1991), L7015 Pt. Aconi to Woodbine, Plan and Profile, Sheets 001 to 023.
7. Newfoundland and Labrador (1986), Bottom Brook to Grandy Brook 138 kV TL No.250 Plan and Profile, Sheets 1 to 59.

Subsequently, ENL has provided an opinion about the expected soil percentages in Newfoundland as 30/50/20 for Normal/Rock/Bog. In view of the significant difference from the percentages estimated above, and in absence of geotechnical drilling information, a cost comparison is also made for this 2nd set of soil conditions.

In the absence of detailed design, the foundation costs (towers, masts, anchors) that were originally estimated were based on very conservative assumptions. We feel that these costs will be reduced after geotechnical investigations and detailed designs. A discount of 15% to the costs of larger foundations has therefore been made for this comparison. The foundation costs for poles have not been discounted because of their relatively straight forward design (i.e. direct burial at 10% of length + 2ft) where further optimization is not possible.

Tower Assembly and Erection

Both the Newfoundland and Nova Scotia lines will generally be built in accessible areas. We have therefore considered that all structures will be erected by road-equipment (i.e. cranes). The exception would be Guyed steel structures, in which case construction by helicopter has been assumed. The helicopter construction methodology will likely be more cost effective due to less stringent requirements of access road (as compared to crane erection for self-support towers) and also due to possibility of laydown areas at regular intervals along the highway. The construction contractor will be allowed to propose either mode of construction.

Stringing

The stringing costs are generally similar between the various structure types. However, some incremental costs are assumed for shorter span structures. These ‘structure-dependent’ stringing costs include insulator hanging, pilot-line and conductor clipping. The costs have accordingly been adjusted.

The estimated comparative costs for each option, excluding the common items, are given in Tables-1 and -2.

The tables also provide the score for each cost. The scoring is on a 1-10 scale (with 10 being the best score). The conversion of each estimated cost to its score is explained as follows; a high cost means a low score. Therefore, the mathematical inverse of the cost is taken. This inverse is multiplied by an appropriate factor (common for all cases) to calculate the score. E.g. the estimated cost of $52,617 k is converted to the score of 7.6 with the formula:

$$\text{Score} = 1/[52{,}617] \times 400{,}000 = 7.60$$

Table 1 Comparative Cost (1st set of Soil Assumptions)

Structure type	Comparative cost excluding common items ($,000)					
	Local Steel			International Steel		
	Cost	diff	Score	Cost	diff	Incremental score
Self-support Lattice Tower	$ 52,617	$ 0	7.60	$ 49,496	$ 0	1.30
Guyed Lattice Tower	$ 47,106	$ (5,511)	8.50	$ 45,297	$ (4,199)	2.20
H-frame Wood Poles (DF)	$ 47,806	$ (4,811)	8.40	$ 47,806	$ (1,690)	
H-frame Wood Poles (WRC)	$ 49,844	$ (2,773)	8.00	$ 49,844	$ 348	
H-frame Wood-eqvt Steel poles	$ 51,475	$ (1,142)	7.80	$ 46,618	$ (2,878)	0.80
Single Wood Poles (DF)	$ 63,204	$ 10,587	6.30	$ 63,204	$ 13,708	
Single Wood Poles (WRC)	$ 65,367	$ 12,750	6.10	$ 65,367	$ 15,871	
Single Wood-eqvt Steel poles	$ 67,270	$ 14,653	5.90	$ 61,718	$ 12,222	0.70

Table 2 Comparative Cost (2nd set of Soil Assumptions)

Structure type	Comparative cost excluding common items ($,000)					
	Local Steel			International Steel		
	Cost	diff	Score	Cost	diff	Incremental score
Self-support Lattice Tower	$ 56,786	$ 0	7.00	$ 53,671	$ 0	1.30
Guyed Lattice Tower	$ 50,935	$ (5,851)	7.90	$ 49,130	$ (4,541)	2.20
H-frame Wood Poles (DF)	$ 52,050	$ (4,736)	7.70	$ 52,050	$ (1,621)	
H-frame Wood Poles (WRC)	$ 54,086	$ (2,700)	7.40	$ 54,086	$ 415	
H-frame Wood-eqvt Steel poles	$ 55,715	$ (1,071)	7.20	$ 50,863	$ (2,808)	0.80
Single Wood Poles (DF)	$ 70,025	$ 13,239	5.70	$ 70,025	$ 16,354	
Single Wood Poles (WRC)	$ 72,188	$ 15,402	5.50	$ 72,188	$ 18,517	
Single Wood-eqvt Steel poles	$ 74,091	$ 17,305	5.40	$ 68,539	$ 14,868	0.70

There is no appreciable change in the relative rankings for the critical structure types with the different assumed soil percentages.

4.2 Maintenance Issues

The scoring has been assigned with consideration to the following issues;

- Maintenance requirement for steel towers are relatively modest consisting of annual (or more regular) visit inspections which can be carried out via helicopter flyovers.
- Steel poles require annual (or more regular) visual inspections. The aerial inspections need to be augmented with ground inspections to observe potential rusting issues at the ground-line.
- Wood poles require testing and preservative treatment at regular intervals, typically starting 10-15 years after installation. Also, visual inspections are required to check insect and bird damages, unacceptable deflection etc.

4.3 Longevity

Longevity is related to maintenance issues. Generally, lines with steel structures can be expected to have longer life-spans as compared to wood-pole lines. During detail design stages, extra galvanization thickness will be considered for the towers near the coastal area and which are susceptible to the proximity to salt-water spray. Typical assumptions include a 40-year useful life for wood pole lines and 50-year useful line for steel-pole and lattice-tower lines.

4.4 Reliability

Due to their inherent longitudinal loading capability, towers have been given a higher reliability score than wood poles.

4.5 Previous Utilization on HVdc Lines

Although there are no known technical reasons against the use of wood poles for HVdc transmission lines, we are not aware of any HVdc transmission line constructed using wood poles in the recent past. A lower weighting has therefore been given to the wood poles for this factor.

4.6 Fire Safety

Steel is inherently more safe than wood during forest fires or lightning strikes.

4.7 Delivery Times

Delivery times for wood poles are generally shorter than steel towers or poles, because of shorter design and fabrication times.

4.8 Availability

A lower 'Availability' score has been assigned to wood poles simply because it is a natural product and deliveries in such large quantities may become an issue.

4.9 Snow Avalanche and Terrain Stability

Snow avalanche or Terrain stability are not a known phenomenon in Newfoundland or Nova Scotia and hence not factored in this comparison.

4.10 Operational Spares

Wood poles are generally common between various transmission lines and can also be procured with relatively shorter notice. Therefore, these are given a higher score as compared to customized steel structures.

4.11 Flexibility of Route Changes

Wood poles offer better design flexibility. Quantity changes due to late changes in the line route are better handled with wood poles than steel structures.

4.12 Heavy Wind Conditions

ENL has recently advised Hatch about the wind conditions (measured at 10 meters above ground level) utilized in the design of existing Newfoundland transmission lines. These are not included in the above comparison. However, higher winds will generally favour the lattice tower options.

4.13 Second Shield-wire

These calculations are based upon a single shield-wire (OPGW) to be installed on towers. Ongoing studies have indicated that two (2) shield-wires, with a shielding angle of 15o, will be required to achieve acceptable lightning performance.

The 2nd shield-wire may slightly increase tower weights and also require an additional shield-wire cross-arm on the H-poles (for achieving the required shielding angle). Due to the relatively small impact, which will not change recommendation, these calculations do not incorporate the impact of the second shield-wire.

5. Comparative Matrix

The evaluation of the different structure types has been carried out on the basis of qualitative and quantitative assessment of different factors discussed in Section 4. For each of the factor, a score (1 to 10) has been assigned to various structure types with '1' accounting for the minimum and '10' for the maximum (best). The weighting given to each factor is as follows:

Table 3 Assigned Weightings

S. No	Factor	Assigned Weight
1	Cost	50%
2	Maintenance	10%
3	Longevity	5%
4	Reliability	10%
5	Previous Utilization	10%
6	Fire Safety	2%
7	Delivery Times	2%
8	Availability	5%
9	Operational Spares	2%
10	Flexibility for Route Changes	4%

The resultant tables are presented in Appendices A thru D.

6. Cost Factor Sensitivity Analysis

A sensitivity analysis has been carried out by varying the weighing of the cost factor from 10% to 90%. For each change in cost factor weighting, the weighting of the remaining factors are adjusted pro-rata for a sum-total of 100% in each case.

This sensitivity analysis is represented in graphical forms in Appendices E and F.

The results of this analysis are tabulated as follows:

Table 4 Cost Factor Sensitivity Analysis

Assumption	Cost-factor Weighting	Highest Weighted Score	2nd Highest Weighted Score	3rd Highest Weighted Score
1st set of soil assumptions and Local steel	0% - 45%	Self-support tower	Guyed tower	H-frame (steel)
	45% - 70%	Guyed tower	Self-support tower	H-frame (steel)
	70% - 90%	Guyed tower	H-frame (steel)	Self-support tower
1st set of soil assumptions and International steel	0% - 25%	Self-support tower	Guyed tower	H-frame (steel)
	25% - 90%	Guyed tower	Self-support tower	H-frame (steel)
2nd set of soil assumptions and Local steel	0% - 45%	Self-support tower	Guyed tower	H-frame (steel)
	45% - 70%	Guyed tower	Self-support tower	H-frame (steel)
	70% - 90%	Guyed tower	H-frame (steel)	Self-support tower
2nd set of soil assumptions and International steel	0% - 25%	Self-support tower	Guyed tower	H-frame (steel)
	25% - 90%	Guyed tower	Self-support tower	H-frame (steel)

7. Wood Poles

This section of the report summarizes the various reasons why wood poles are not the recommended structure type:

1. Because of the large conductor size and heavy wind conditions, the spans for wood poles will be limited to only 150~170 m. As a result, the number of structures is double to that of towers. In addition to the cost of structures themselves, this considerably drives-up the cost of insulators. There is also an incremental cost on stringing since travellers and conductor-clipping will be required at more structures.

2. The expected wood poles will be 85 ft long, which is generally above average industry utilization. Sourcing of a considerably large number of 85 ft poles will likely be an issue.
3. Wood poles require considerably more maintenance than steel structures. This includes testing and preservative treatment at regular intervals. Also, wood poles are susceptible to insect and bird damage. Generally, higher maintenance requirements for wood poles are justified if the initial capital cost is lower than steel structures; which is not the case for this project.
4. The useful life of wood poles is less than steel structures. Obviously, the life can be extended by more extensive maintenance and structure-replacement operations at later stages.
5. Steel structures are inherently more reliable than wood poles.
6. Wood poles are susceptible to deflection which impacts the conductor-to-structure clearances.
7. Wood poles are susceptible to fires during forest fires or lightning strikes.
8. Wood poles have not been used on the existing HVdc transmission lines; and therefore don't have a proven track record for similar applications.

8. Recommendation

Based upon the factors considered in this report; Guyed Lattice Steel Towers provide the highest weighted score compared with other structure types. The Self-support Steel Towers are ranked 2nd, followed by Wood-equivalent Steel H-frames. This ranking does not change between local and international procurement of steel.

The access road requirements for guyed tower construction have a relatively lower environmental impact than the access roads required for self-support and poles, where heavier cranes are utilized. The guyed tower provides this additional benefit.

The existing transmission line (TL214), which is parallel to the HVdc line route in Newfoundland, is also of guyed construction. Therefore, it is reasonable to assume that guyed towers have a track record for application in the local setting and also that the maintenance crews are familiar with their maintenance requirements.

The HVdc transmission line route in Nova Scotia is located in urban (or near urban) areas. Guyed towers are generally not recommended in urban areas because of their larger foot-print and for security reasons. The easement has several restrictive areas that are not suitable to the larger foot-print. In addition, helicopter construction will likely not be possible, and this will reduce the cost advantage of guyed towers.

Hatch therefore provides the following recommendations to ENL:

1. All tangent (and potentially light angle) structures in Newfoundland are recommended as Guyed Lattice Towers.

2. All tangent (and potentially light angle) structure in Nova Scotia are recommended as Self-support Lattice Towers.
3. All Heavy angle and Dead-end structures will be Self-support Lattice Towers, as also recommended in the RFP documents.
4. All River Crossings (or long span structures) will be Self-support Lattice Towers, as also recommended in the RFP documents. Hatch further recommends that these crossing towers are dead-end towers for reliability considerations.

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Appendix – A Scoring Table – 1st Set of Soil Assumptions
Appendix – B Weighted Scores - 1st Set of Soil Assumptions
Appendix – C Scoring Table – 2nd Set of Soil Assumptions
Appendix – D Weighted Scores – 2nd Set of Soil Assumptions
Appendix – E Cost Factor - Sensitivity Analysis – 1st Set of Soil Assumptions
Appendix – F Cost Factor - Sensitivity Analysis – 2nd Set of Soil Assumptions
Appendix – G Cost Breakdown – 1st Set of Soil Assumptions
Appendix – H Cost Breakdown – 2nd Set of Soil Assumptions

APPENDIX – A

SCORING TABLE

1st SET OF SOIL ASSUMPTIONS

Factor		Score (1-10)							
		Towers		H-frames			Single Poles		
		Self-support	Guyed	Wood (DF)	Wood (WRC)	Wood eqvt. steel	Wood (DF)	Wood (WRC)	Wood eqvt. steel
Cost		7.6	8.5	8.4	8.0	7.8	6.3	6.1	5.9
Maintenance issues		8	6	5	5	6	5	5	6
Longevity		8	7	4	4	7	3	3	6
Reliability		8	7	6	6	7	5	5	6
Previous utilization on HVdc lines		6	6	2	2	4	1	1	3
Fire safety		7	7	5	5	7	5	5	7
Delivery times		4	4	6	6	3	6	6	3
Availability		6	6	4	4	6	4	4	4
Operational spares		5	5	7	7	5	7	7	5
Flexibility of route changes		6	6	7	7	7	7	7	7
Cost savings_International Steel procurement									

APPENDIX – B

WEIGHTED-SCORES

1st SET OF SOIL ASSUMPTIONS

Factor	Assigned weighting	Weighted Score							
		Towers		H-frames			Single Poles		
		Self-support	Guyed	Wood (DF)	Wood (WRC)	Wood eqvt. Steel	Wood (DF)	Wood (WRC)	Wood eqvt. steel
Cost (based upon	50%	3.8	4.3	4.2	4.0	3.9	3.2	3.1	3.0
Maintenance issues	10%	0.8	0.6	0.5	0.5	0.6	0.5	0.5	0.6
Longevity	5%	0.4	0.4	0.2	0.2	0.4	0.2	0.2	0.3
Reliability	10%	0.8	0.7	0.6	0.6	0.7	0.5	0.5	0.6
Previous utilization on HVdc lines	10%	0.6	0.6	0.2	0.2	0.4	0.1	0.1	0.3
Fire safety	2%	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1
Delivery times	2%	0.1	0.1	0.1	0.1	0.0	0.1	0.1	0.0
Availability	5%	0.3	0.3	0.2	0.2	0.3	0.2	0.2	0.2
Operational spares	2%	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1
Flexibility of route changes	4%	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3
Total score with local procurement	**100%**	**7.3**	**7.5**	**6.5**	**6.3**	**6.8**	**5.3**	**5.2**	**5.5**
Cost savings_International Steel procurement	50%	0.7	1.1	0.0	0.0	0.4	0.0	0.0	0.4
Total score with International steel procurement		**8.0**	**8.6**	**6.5**	**6.3**	**7.2**	**5.3**	**5.2**	**5.9**

APPENDIX – C

SCORING TABLE

2nd SET OF SOIL ASSUMPTIONS

Factor		Score (1-10)							
		Towers		H-frames			Single Poles		
		Self-support	Guyed	Wood (DF)	Wood (WRC)	Wood eqvt. steel	Wood (DF)	Wood (WRC)	Wood eqvt. steel
Cost		7.0	7.9	7.7	7.4	7.2	5.7	5.5	5.4
Maintenance issues		8	6	5	5	6	5	5	6
Longevity		8	7	4	4	7	3	3	6
Reliability		8	7	6	6	7	5	5	6
Previous utilization on HVdc lines		6	6	2	2	4	1	1	3
Fire safety		7	7	5	5	7	5	5	7
Delivery times		4	4	6	6	3	6	6	3
Availability		6	6	4	4	6	4	4	4
Operational spares		5	5	7	7	5	7	7	5
Flexibility of route changes		6	6	7	7	7	7	7	7
Cost savings_International Steel procurement		1.3	2.2			0.8			0.7

APPENDIX – D

WEIGHTED-SCORES

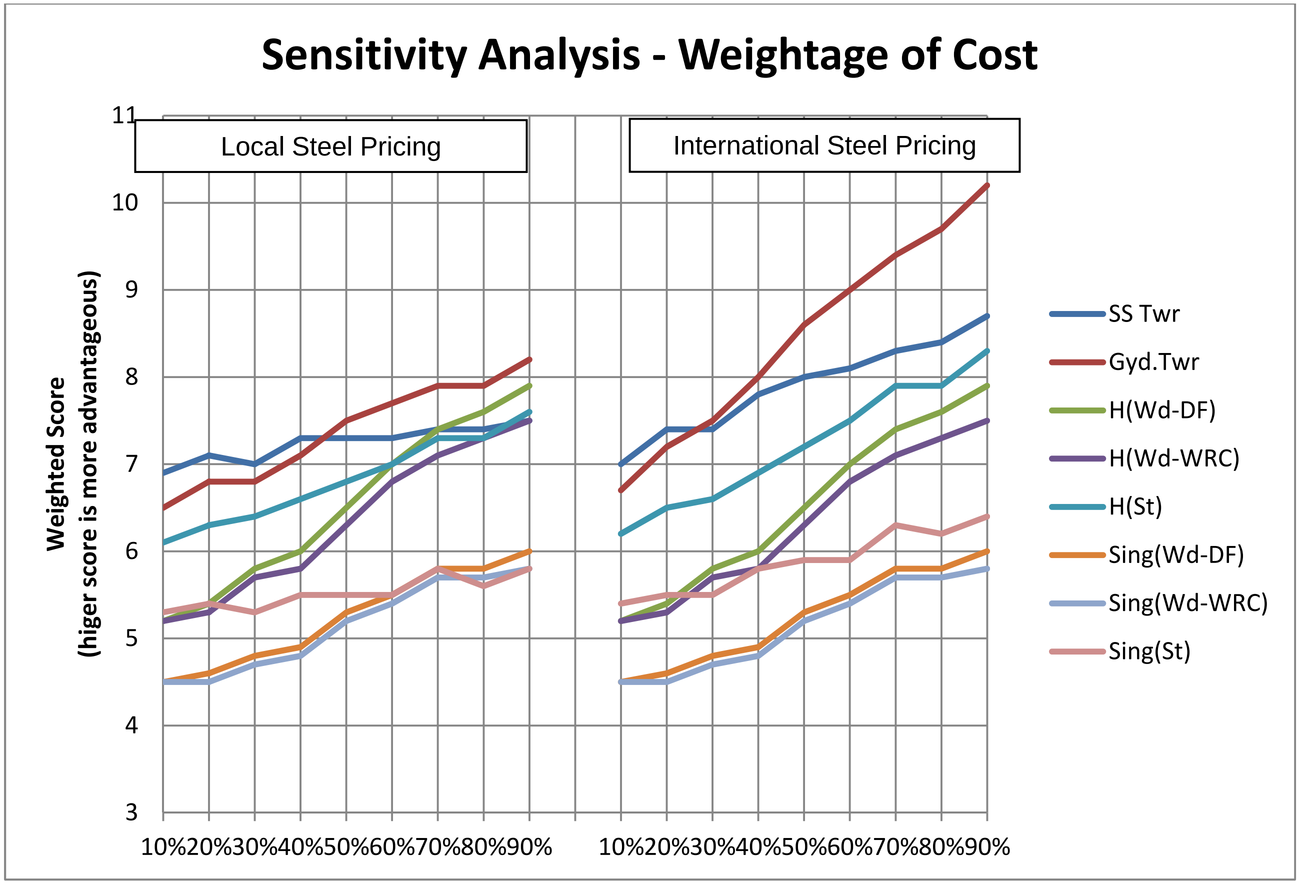
2nd SET OF SOIL ASSUMPTIONS

Factor	Assigned weighing	Weighted Score							
		Towers		H-frames			Single Poles		
		Self-support	Guyed	Wood (DF)	Wood (WRC)	Wood eqvt. steel	Wood (DF)	Wood (WRC)	Wood eqvt. steel
Cost (based upon costs excluding common items)	50%	3.5	4.0	3.9	3.7	3.6	2.9	2.8	2.7
Maintenance issues	10%	0.8	0.6	0.5	0.5	0.6	0.5	0.5	0.6
Longevity	5%	0.4	0.4	0.2	0.2	0.4	0.2	0.2	0.3
Reliability	10%	0.8	0.7	0.6	0.6	0.7	0.5	0.5	0.6
Previous utilization on HVdc lines	10%	0.6	0.6	0.2	0.2	0.4	0.1	0.1	0.3
Fire safety	2%	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1
Delivery times	2%	0.1	0.1	0.1	0.1	0.0	0.1	0.1	0.0
Availability	5%	0.3	0.3	0.2	0.2	0.3	0.2	0.2	0.2
Operational spares	2%	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1
Flexibility of route changes	4%	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3
Total score with local procurement	**100%**	**7**	**7.2**	**6.2**	**6**	**6.5**	**5**	**4.9**	**5.2**
Cost savings_International Steel procurement	50%	0.7	1.1	0.0	0.0	0.4	0.0	0.0	0.4
Total score with International steel procurement		**7.7**	**8.3**	**6.2**	**6.0**	**6.9**	**5.0**	**4.9**	**5.6**

APPENDIX – E

COST FACTOR - SENSITIVITY ANALYSIS

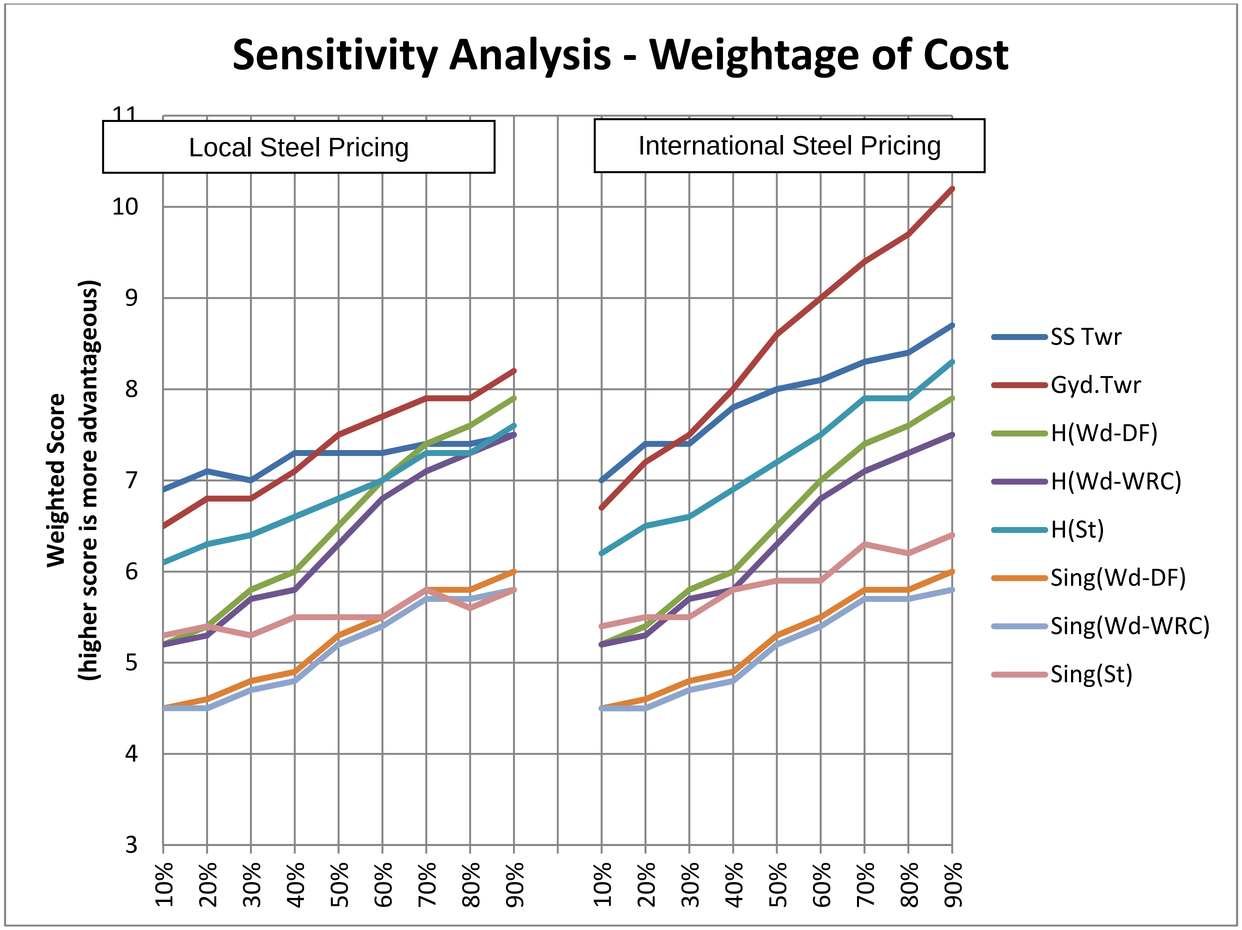
1st SET OF SOIL ASSUMPTIONS



APPENDIX – F

COST FACTOR - SENSITIVITY ANALYSIS

2nd SET OF SOIL ASSUMPTIONS



APPENDIX – G

COST BREAKDOWN

1st SET OF SOIL ASSUMPTIONS

Maritime Link Project
Evaluation of Structure Types for +/-200 kV HVdc Transmission Line
Preliminary Comparision of Costs (excluding common items) for Structure Evaluation Only
Conductor: 1xACSR Bluebird

	Description	Self-support Lattice Tower			Guyed Lattice Tower			H-Frame Wood Poles (DF)			H-Frame Wood Poles (WRC)			H-Frame Steel Poles			Single Wood Pole (DF)			Single Wood Pole (WRC)			Single Steel Pole		
Material costs per structure																									
	Galvanized steel	$ 18,840	$ 18,840	$ 18,840	$ 11,466	$ 11,466	$ 11,466																		
	Wood pole (WRC) 85/1										$ 13,000	$ 13,000	$ 13,000												
	Wood pole (DF) 85/1							$ 11,000	$ 11,000	$ 11,000															
	Wood pole (WRC) 80/H2																			$ 7,000	$ 7,000	$ 7,000			
	Wood pole (DF) 80/H2																$ 6,000	$ 6,000	$ 6,000						
	Wood equivalent steel pole (incremental cost)													$ 14,300	$ 14,300	$ 14,300				$ -	$ -	$ -	$ 7,700	$ 7,700	$ 7,700
	Steel crossarm							$ 2,000	$ 2,000	$ 2,000	$ 2,000	$ 2,000	$ 2,000	$ 2,000	$ 2,000	$ 2,000				$ -	$ -	$ -			
	Steel davit-arms										$ -	$ -	$ -				$ 3,000	$ 3,000	$ 3,000	$ 3,000	$ 3,000	$ 3,000	$ 3,000	$ 3,000	$ 3,000
	Steel crossbracing							$ 2,000	$ 2,000	$ 2,000	$ 2,000	$ 2,000	$ 2,000	$ 2,000	$ 2,000	$ 2,000				$ -	$ -	$ -			
	Insulators	$ 3,590	$ 3,590	$ 3,590	$ 3,590	$ 3,590	$ 3,590	$ 3,590	$ 3,590	$ 3,590	$ 3,590	$ 3,590	$ 3,590	$ 3,590	$ 3,590	$ 3,590	$ 3,590	$ 3,590	$ 3,590	$ 3,590	$ 3,590	$ 3,590	$ 3,590	$ 3,590	$ 3,590
	2nd shied-wire for H-Frames							$ 510	$ 510	$ 510	$ 510	$ 510	$ 510	$ 510	$ 510	$ 510									
	Guywire and accessories				$ 1,200	$ 1,200	$ 1,200			$ 600	$ -	$ -	$ 600			$ 600			$ 600	$ -	$ -	$ 600			$ 600
	Misc items per structure	$ 600	$ 600	$ 600	$ 900	$ 900	$ 900	$ 900	$ 900	$ 900	$ 900	$ 900	$ 900	$ 1,200	$ 1,200	$ 1,200	$ 540	$ 540	$ 540	$ 540	$ 540	$ 540	$ 720	$ 720	$ 720
	sub-total Material	$ 23,030	$ 23,030	$ 23,030	$ 17,156	$ 17,156	$ 17,156	$ 20,000	$ 20,000	$ 20,600	$ 22,000	$ 22,000	$ 22,600	$ 23,600	$ 23,600	$ 24,200	$ 13,130	$ 13,130	$ 13,730	$ 14,130	$ 14,130	$ 14,730	$ 15,010	$ 15,010	$ 15,610
Construction costs per structure											$ -	$ -	$ -												
	Wood Pole foundation (normal soil & till)							$ 10,000			$ 10,000	$ -	$ -	$ 10,000			$ 5,000			$ 5,000	$ -	$ -	$ 5,000		
	Wood pole foundation (rock)								$ 16,000		$ -	$ 16,000	$ -		$ 16,000			$ 8,000		$ -	$ 8,000	$ -		$ 8,000	
	Wood pole foundation (bog)									$ 24,000	$ -	$ -	$ 24,000			$ 24,000			$ 12,000	$ -	$ -	$ 12,000			$ 12,000
	Self-support foundation (normal soil & till)	$ 60,000									$ -	$ -	$ -							$ -	$ -	$ -			
	Self-support foundation (rock)		$100,000								$ -	$ -	$ -							$ -	$ -	$ -			
	Self-support foundation (bog)			$ 80,000							$ -	$ -	$ -							$ -	$ -	$ -			
	Guyed mast foundation (normal soil & till)				$ 35,000						$ -	$ -	$ -							$ -	$ -	$ -			
	Guyed mast foundation (rock)					$ 50,000					$ -	$ -	$ -							$ -	$ -	$ -			
	Guyed mast foundation (bog)						$ 65,000				$ -	$ -	$ -							$ -	$ -	$ -			
	Guyed mast anchor (normal soil & till)				$ 24,000						$ -	$ -	$ -							$ -	$ -	$ -			
	Guyed mast anchor (rock)					$ 28,000					$ -	$ -	$ -							$ -	$ -	$ -			
	Guyed mast anchor (bog)						$ 80,000			$ 40,000	$ -	$ -	$ 40,000			$ 40,000			$ 40,000	$ -	$ -	$ 40,000			$ 40,000
	Potential cost saving in detailed foundation design	$ (9,000)	$ (15,000)	$ (12,000)	$ (8,850)	$ (11,700)	$ (21,750)			$ (6,000)	$ -	$ -	$ (6,000)			$ (6,000)			$ (6,000)	$ -	$ -	$ (6,000)			$ (6,000)
											$ -	$ -	$ -							$ -	$ -	$ -			
	Tower Assembly	$ 6,280	$ 6,280	$ 6,280	$ 3,640	$ 3,640	$ 3,640				$ -	$ -	$ -							$ -	$ -	$ -			
	Wood pole framing							$ 3,000	$ 3,000	$ 3,000	$ 3,000	$ 3,000	$ 3,000	$ 3,000	$ 3,000	$ 3,000	$ 1,800	$ 1,800	$ 1,800	$ 1,800	$ 1,800	$ 1,800	$ 1,800	$ 1,800	$ 1,800
	Self-supporting tower erection, include insul	$ 18,000	$ 18,000	$ 18,000							$ -	$ -	$ -							$ -	$ -	$ -			
	Guyed mast tower erection, include insul (helicopter)				$ 12,000	$ 12,000	$ 12,000				$ -	$ -	$ -							$ -	$ -	$ -			
	Wood pole erection, include insul							$ 6,000	$ 6,000	$ 6,000	$ 6,000	$ 6,000	$ 6,000	$ 6,000	$ 6,000	$ 6,000	$ 3,600	$ 3,600	$ 3,600	$ 3,600	$ 3,600	$ 3,600	$ 3,600	$ 3,600	$ 3,600
	Stringing - 2nd shieldwire							$ 850	$ 850	$ 850	$ 850	$ 850	$ 850	$ 850	$ 850	$ 850									
	sub-total Construction	$ 75,280	$109,280	$ 92,280	$ 65,790	$ 81,940	$138,890	$ 19,850	$ 25,850	$ 67,850	$ 19,850	$ 25,850	$ 67,850	$ 19,850	$ 25,850	$ 67,850	$ 10,400	$ 13,400	$ 51,400	$ 10,400	$ 13,400	$ 51,400	$ 10,400	$ 13,400	$ 51,400
Total cost per structure		$ 98,310	$132,310	$115,310	$ 82,946	$ 99,096	$156,046	$ 39,850	$ 45,850	$ 88,450	$ 41,850	$ 47,850	$ 90,450	$ 43,450	$ 49,450	$ 92,050	$ 23,530	$ 26,530	$ 65,130	$ 24,530	$ 27,530	$ 66,130	$ 25,410	$ 28,410	$ 67,010
Comparitive line cost (excluding common items)																									
	Newfoundland																								
	Total number of suspension structures		371			371			761			761			761			1616			1616			1616	
68%	In normal soil	252			252			517			517			517			1099			1099			1099		
20%	In rock		74			74			152			152			152			323			323			323	
12%	In bog			45			45			92			92			92			194			194			194
	Comparitive cost (excluding common items)	**$**		**39,754,000**	**$**		**35,258,000**	**$**		**35,709,000**	**$**		**37,231,000**	**$**		**38,449,000**	**$**		**47,064,000**	**$**		**48,680,000**	**$**		**50,102,000**
	Nova Scotia																								
	Total number of suspension structures		126			126			258			258			258			547			547			547	
	In normal soil	103			103			211			211			211			448			448			448		
	In rock		5			5			11			11			11			22			22			22	
	In bog			18			18			36			36			36			77			77			77
	Comparitive cost (excluding common items)	**$**		**12,863,000**	**$**		**11,848,000**	**$**		**12,097,000**	**$**		**12,613,000**	**$**		**13,026,000**	**$**		**16,140,000**	**$**		**16,687,000**	**$**		**17,168,000**
	Nefoundland + Nova Scotia																								
	Length																								
	Tangent structures			497			497			1,019			1,019			1,019			2,163			2,163			2,163
	Comparitive cost (excluding common items)	**$**		**52,617,000**	**$**		**47,106,000**	**$**		**47,806,000**	**$**		**49,844,000**	**$**		**51,475,000**	**$**		**63,204,000**	**$**		**65,367,000**	**$**		**67,270,000**
	Comparison utilizing overseas steel procurement	**$**		**49,496,000**	**$**		**45,297,000**	**$**		**47,806,000**	**$**		**49,844,000**	**$**		**46,618,000**	**$**		**63,204,000**	**$**		**65,367,000**	**$**		**61,718,000**

APPENDIX – H

COST BREAKDOWN

2nd SET OF SOIL ASSUMPTIONS

Maritime Link Project
Evaluation of Structure Types for +/-200 kV HVdc Transmission Line
Preliminary Comparision of Costs (excluding common items) for Structure Evaluation Only
Conductor: 1xACSR Bluebird

	Description	Self-support Lattice Tower			Guyed Lattice Tower			H-Frame Wood Poles (DF)			H-Frame Wood Poles (WRC)			H-Frame Steel Poles			Single Wood Pole (DF)			Single Wood Pole (WRC)			Single Steel Pole		
Material costs per structure																									
	Galvanized steel	$ 18,840	$ 18,840	$ 18,840	$ 11,466	$ 11,466	$ 11,466																		
	Wood pole (WRC) 85/1										$ 13,000	$ 13,000	$ 13,000												
	Wood pole (DF) 85/1							$ 11,000	$ 11,000	$ 11,000															
	Wood pole (WRC) 80/H2																			$ 7,000	$ 7,000	$ 7,000			
	Wood pole (DF) 80/H2																$ 6,000	$ 6,000	$ 6,000						
	Wood equivalent steel pole (incremental cost)													$ 14,300	$ 14,300	$ 14,300				$ -	$ -	$ -	$ 7,700	$ 7,700	$ 7,700
	Steel crossarm							$ 2,000	$ 2,000	$ 2,000	$ 2,000	$ 2,000	$ 2,000	$ 2,000	$ 2,000	$ 2,000				$ -	$ -	$ -			
	Steel davit-arms										$ -	$ -	$ -				$ 3,000	$ 3,000	$ 3,000	$ 3,000	$ 3,000	$ 3,000	$ 3,000	$ 3,000	$ 3,000
	Steel crossbracing							$ 2,000	$ 2,000	$ 2,000	$ 2,000	$ 2,000	$ 2,000	$ 2,000	$ 2,000	$ 2,000				$ -	$ -	$ -			
	Insulators	$ 3,590	$ 3,590	$ 3,590	$ 3,590	$ 3,590	$ 3,590	$ 3,590	$ 3,590	$ 3,590	$ 3,590	$ 3,590	$ 3,590	$ 3,590	$ 3,590	$ 3,590	$ 3,590	$ 3,590	$ 3,590	$ 3,590	$ 3,590	$ 3,590	$ 3,590	$ 3,590	$ 3,590
	2nd shied-wire for H-Frames							$ 510	$ 510	$ 510	$ 510	$ 510	$ 510	$ 510	$ 510	$ 510									
	Guywire and accessories				$ 1,200	$ 1,200	$ 1,200			$ 600	$ -	$ -	$ 600			$ 600			$ 600	$ -	$ -	$ 600			$ 600
	Misc items per structure	$ 600	$ 600	$ 600	$ 900	$ 900	$ 900	$ 900	$ 900	$ 900	$ 900	$ 900	$ 900	$ 1,200	$ 1,200	$ 1,200	$ 540	$ 540	$ 540	$ 540	$ 540	$ 540	$ 720	$ 720	$ 720
	sub-total Material	$ 23,030	$ 23,030	$ 23,030	$ 17,156	$ 17,156	$ 17,156	$ 20,000	$ 20,000	$ 20,600	$ 22,000	$ 22,000	$ 22,600	$ 23,600	$ 23,600	$ 24,200	$ 13,130	$ 13,130	$ 13,730	$ 14,130	$ 14,130	$ 14,730	$ 15,010	$ 15,010	$ 15,610
Construction costs per structure											$ -	$ -	$ -												
	Wood Pole foundation (normal soil & till)							$ 10,000			$ 10,000	$ -	$ -	$ 10,000			$ 5,000			$ 5,000	$ -	$ -	$ 5,000		
	Wood pole foundation (rock)								$ 16,000		$ -	$ 16,000	$ -		$ 16,000			$ 8,000		$ -	$ 8,000	$ -		$ 8,000	
	Wood pole foundation (bog)									$ 24,000	$ -	$ -	$ 24,000			$ 24,000			$ 12,000	$ -	$ -	$ 12,000			$ 12,000
	Self-support foundation (normal soil & till)	$ 60,000									$ -	$ -	$ -							$ -	$ -	$ -			
	Self-support foundation (rock)		$100,000								$ -	$ -	$ -							$ -	$ -	$ -			
	Self-support foundation (bog)			$ 80,000							$ -	$ -	$ -							$ -	$ -	$ -			
	Guyed mast foundation (normal soil & till)				$ 35,000						$ -	$ -	$ -							$ -	$ -	$ -			
	Guyed mast foundation (rock)					$ 50,000					$ -	$ -	$ -							$ -	$ -	$ -			
	Guyed mast foundation (bog)						$ 65,000				$ -	$ -	$ -							$ -	$ -	$ -			
	Guyed mast anchor (normal soil & till)				$ 24,000						$ -	$ -	$ -							$ -	$ -	$ -			
	Guyed mast anchor (rock)					$ 28,000					$ -	$ -	$ -							$ -	$ -	$ -			
	Guyed mast anchor (bog)						$ 80,000			$ 40,000	$ -	$ -	$ 40,000			$ 40,000			$ 40,000	$ -	$ -	$ 40,000			$ 40,000
	Potential cost saving in detailed foundation design	$ (9,000)	$ (15,000)	$ (12,000)	$ (8,850)	$ (11,700)	$ (21,750)			$ (6,000)	$ -	$ -	$ (6,000)			$ (6,000)			$ (6,000)	$ -	$ -	$ (6,000)			$ (6,000)
											$ -	$ -	$ -							$ -	$ -	$ -			
	Tower Assembly	$ 6,280	$ 6,280	$ 6,280	$ 3,640	$ 3,640	$ 3,640				$ -	$ -	$ -							$ -	$ -	$ -			
	Wood pole framing							$ 3,000	$ 3,000	$ 3,000	$ 3,000	$ 3,000	$ 3,000	$ 3,000	$ 3,000	$ 3,000	$ 1,800	$ 1,800	$ 1,800	$ 1,800	$ 1,800	$ 1,800	$ 1,800	$ 1,800	$ 1,800
	Self-supporting tower erection, include insul	$ 18,000	$ 18,000	$ 18,000							$ -	$ -	$ -							$ -	$ -	$ -			
	Guyed mast tower erection, include insul (helicopter)				$ 12,000	$ 12,000	$ 12,000				$ -	$ -	$ -							$ -	$ -	$ -			
	Wood pole erection, include insul							$ 6,000	$ 6,000	$ 6,000	$ 6,000	$ 6,000	$ 6,000	$ 6,000	$ 6,000	$ 6,000	$ 3,600	$ 3,600	$ 3,600	$ 3,600	$ 3,600	$ 3,600	$ 3,600	$ 3,600	$ 3,600
	Stringing - 2nd shieldwire							$ 850	$ 850	$ 850	$ 850	$ 850	$ 850	$ 850	$ 850	$ 850									
	sub-total Construction	$ 75,280	$109,280	$ 92,280	$ 65,790	$ 81,940	$138,890	$ 19,850	$ 25,850	$ 67,850	$ 19,850	$ 25,850	$ 67,850	$ 19,850	$ 25,850	$ 67,850	$ 10,400	$ 13,400	$ 51,400	$ 10,400	$ 13,400	$ 51,400	$ 10,400	$ 13,400	$ 51,400
Total cost per structure		$ 98,310	$132,310	$115,310	$ 82,946	$ 99,096	$156,046	$ 39,850	$ 45,850	$ 88,450	$ 41,850	$ 47,850	$ 90,450	$ 43,450	$ 49,450	$ 92,050	$ 23,530	$ 26,530	$ 65,130	$ 24,530	$ 27,530	$ 66,130	$ 25,410	$ 28,410	$ 67,010
Comparitive line cost (excluding common items)																									
	Newfoundland																								
	Total number of suspension structures		370			370			760			760			760			1616			1616			1616	
30%	In normal soil	111			111			228			228			228			485			485			485		
50%	In rock		185			185			380			380			380			808			808			808	
20%	In bog			74			74			152			152			152			323			323			323
	Comparitive cost (excluding common items)	**$**		**43,923,000**	**$**		**39,087,000**	**$**		**39,953,000**	**$**		**41,473,000**	**$**		**42,689,000**	**$**		**53,885,000**	**$**		**55,501,000**	**$**		**56,923,000**
	Nova Scotia																								
	Total number of suspension structures		126			126			258			258			258			547			547			547	
	In normal soil	103			103			211			211			211			448			448			448		
	In rock		5			5			11			11			11			22			22			22	
	In bog			18			18			36			36			36			77			77			77
	Comparitive cost (excluding common items)	**$**		**12,863,000**	**$**		**11,848,000**	**$**		**12,097,000**	**$**		**12,613,000**	**$**		**13,026,000**	**$**		**16,140,000**	**$**		**16,687,000**	**$**		**17,168,000**
	Nefoundland + Nova Scotia																								
	Length																								
	Tangent structures			496			496			1,018			1,018			1,018			2,163			2,163			2,163
	Comparitive cost (excluding common items)	**$**		**56,786,000**	**$**		**50,935,000**	**$**		**52,050,000**	**$**		**54,086,000**	**$**		**55,715,000**	**$**		**70,025,000**	**$**		**72,188,000**	**$**		**74,091,000**
	Comparison utilizing overseas steel procurement	**$**		**53,671,000**	**$**		**49,130,000**	**$**		**52,050,000**	**$**		**54,086,000**	**$**		**50,863,000**	**$**		**70,025,000**	**$**		**72,188,000**	**$**		**68,539,000**

NON-CONFIDENTIAL

Request IR-177:

With reference to Appendix 3.01, page 63, please explain advantages and disadvantages of the NSPML currently planned approach to implement the overhead HVDC transmission lines using a fixed-price (lump sum) Supply-Build contracting strategy, except for long-lead items which will be directly procured by NSPML.

Response IR-177:

The primary advantages of the proposed fixed-price (lump sum) Supply-Build contracting strategy are to maintain control of the final design by NSPML, and to obtain relative cost certainty and single-point accountability at the conclusion of the design process. By directly procuring long-lead items, NSPML can finalize detailed design in parallel with the procurement and manufacture of the long-lead items. This will permit schedule compression by commencement of the long-lead procurement before the end of the design process. Inclusion of all other project materials in the scope of the supply-build contractor has the benefit of reducing the volume of procurement activity by NSPML, and placing accountability on the contractor for timely supply and delivery of quality materials to the project site.

This increased cost certainty and transfer of supply chain risk is achieved at the risk of potential cost increases due to contractor mark-ups on the short-lead-time materials that will be supplied by the contractor. The level of overall project cost increase is effectively managed by removal of a large dollar value of long-lead materials from the contractor’s supply scope.

NON-CONFIDENTIAL

Request IR-178:

With reference to Appendix 3.01, page 63, please identify the long-term items that will be directly procured by NSPML.

Response IR-178:

The primary long lead items being considered for direct procurement by NSPML are lattice steel towers and insulators. Other items that may be directly procured include conductor wire and OPGW shield wires.

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Request IR-179:

With reference to Appendix 3.01, page 64, please provide the statistical data for applications where the two types of the cable technology have been used: mass impregnated (MI) and cross-linked polyethylene (XLPE). The data should include, but not be limited to, the name of the project, year of installation, name of the cable vendor, land-based and subsea length, capacity, voltage, HVDC/AC technology type, cable type, core material (copper or aluminum), number of forced outages caused by the cable failure, the root cause of the failure, and duration of the outages.

Response IR-179:

Please refer to LPRA IR-18.

NON-CONFIDENTIAL

Request IR-180:

With reference to Appendix 3.01, page 65, with regard to the specific design parameters established regardless of the type of cable insulation, have any parameters been established for the cable flexibility and avoidance of kinks during installation?

Response IR-180:

The cable manufacturer will specify an MBR (minimum bending radius) for the cable during installation and laying. This MBR will be monitored and adhered to during handling in order to prevent damage to cable.

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Request IR-181:

With reference to Appendix 3.01, page 66, would separation of the two cables in the Maritime Link bipolar configuration require separate horizontal drilling or trenching for each cable? If so, how would the areas be determined where such separation would be considered practical in order to provide reduced risk of a single event damaging both cables?

Response IR-181:

Separate HDD will be constructed in the landfalls areas to pull in the cables. Separation distance between the cables on seabed will be determined based on worldwide cable damage statistical data, and industry best practices.

NON-CONFIDENTIAL

Request IR-182:

With reference to Appendix 3.01, page 66, are the underground cables from the land/sea cable transition sites to the overhead/underground transition compounds expected to be the same type as the submarine cables?

Response IR-182:

The cables will be the same type.

NON-CONFIDENTIAL

Request IR-183:

With reference to Appendix 3.01, page 68, please explain the NSPML approach in reviewing and evaluation of the bids it has received in response to the cable contract RFP. In particular, identify the criteria, factors, and evaluation methodology, including the score system, and provide all the work papers, tables, memos, spreadsheets, etc., in electronic form, prepared in the course of the analysis and evaluation of the bids.

Response IR-183:

The RFPs are evaluated based on technical criteria, quality criteria, health safety and environment criteria, commercial criteria and benefits criteria. The competitive solicitation process is in progress and the requested documents are not available.

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Request IR-184:

With reference to Appendix 3.01, page 69, would washing the termination bushings require de-energizing the facility to avoid flashovers during the procedure?

Response IR-184:

Insulators and bushings are commonly washed with the facilities energized, using either wet and dry spray materials.

NON-CONFIDENTIAL

Request IR-185:

With reference to Appendix 3.01, page 73:

(a) **Please exp 1 lain why the maximum ambient temperature at Woodline is specified at 40°C while at Bottom Brook it is specified at 30°C.**

(b) **Explain what are the power transfer and reactive output ratings guarantees when the ambient temperature at Woodline is in the range from 30°C to 40°C.**

Response IR-185:

(a) The 30°C ambient temperature figure at Bottom Brook is correct, and the value at Woodbine should be approximately the same. The value of 40°C shown for Woodbine was an error.

(b) Specification requires vendors to provide the full active and reactive power rating at maximum ambient temperature without the redundant cooling.

NON-CONFIDENTIAL

Request IR-186:

With reference to Appendix 3.01, page 74, please describe the operating procedures for switching the Maritime Link facility from one operating mode to another.

Response IR-186:

Details of operating procedures have not yet been settled for all intermodal transitions. The transition from bipolar mode to monopolar with earth return would happen automatically in the event of a pole failure, and it would also occur automatically when remote operator control actions are instituted to shut down one pole. The transition from normal bipolar mode to reduced voltage mode could also be instituted by remote operator control. The transition from monopolar with earth return to monopolar with metallic return, and vice versa, would require external physical switching by operating crews, and safe switching sequences will need to be developed to “make” the metallic return connection before “breaking” the earth return connection

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Request IR-187:

With reference to Appendix 3.01, page 75:

(a) Do the required nominal continuous guaranteed reactive output (Mvar) levels, 250 Mvar in the Bipole (Dual Monopole) operating mode and 125 Mvar in the Monopolar Ground Return operating mode, represent just the reactive lagging capabilities, or both lagging and leading capabilities?

(b) If lagging only, what are the requirements for the leading reactive capabilities under the specified operating modes?

Response IR-187:

a) Nominal continuous guaranteed output (Mvar) levels represent both lagging and leading (inductive or capacitive) capabilities: ±250 MVAr for bipolar and ±125 MVAr for monopolar with earth return.

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b) See response to (a)

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Request IR-188:

With reference to Appendix 3.01, page 75, what would be the maximum reactive support to the Nova Scotia system from the Maritime Link at the 170 MW real power level:

(a) under normal operating mode;

(b) under one pole operating mode?

Response IR-188:

Since VSC based HVdc converters allow independent control of active and reactive power flow over the full operating range, the full range of reactive power (generation/absorption) capability remains available at reduced power transfer, as follows:

(a) 250 MVAr

(b) 125 MVAr

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Request IR-189:

With reference to Appendix 3.01, page 75-76:

(a) Are the system performance requirements consistent with the performance characteristics of the existing HVDC converters based on the VSC technology?

(b) Please provide the operation functionality specifications of all VSC converters operating worldwide, including ABB HVDC Light and Siemens HVDC plus installations.

Response IR-189:

(a) Yes, the system performance requirements documented in Hingorani IR-10 are consistent with the performance characteristics of existing HVdc converters based on the VSC technology. The voltage and power levels for the Maritime Link converters are within the range of proven applications of VSC technology.

(b) Please see the list of VSC based projects in Figure 3-6 of the application, which includes projects by ABB, Siemens and Alstom Grid, with the operating voltage and power capacity of each project. As of the end of 2012, +/- 200 kV and 500 MW was a proven voltage and power level for VSC technology, and the Dolwin1 project in Germany is about to go in service at +/-320 kV and 800 MW.

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Request IR-190:

With reference to Appendix 3.01, page 75-76:

(a) **Will the Maritime Link have black start capability?**

(b) **If so, why is this feature not included in the list of the system performance requirements?**

Response IR-190:

(a) The Technical Specification for the converter will include black-start capability.

(b) The list provided in Appendix 3.01, page 75-76 is a preliminary list, and the absence of black-start capability was an oversight.

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Request IR-191:

With reference to Appendix 3.01, page 76, please explain the functionality of the required frequency stabilization controls and automatic AGC control of the Maritime Link under contingencies either in the Newfoundland or in the Nova Scotia systems that cause the demand-supply imbalance.

Response IR-191:

Frequency stabilization controls shall be provided to ensure that the HVdc link contributes to stabilization of the frequencies on the Island of Newfoundland and Nova Scotia within the capability of the equipment. The ac frequencies in Nova Scotia and on the Island of Newfoundland shall be monitored and the response shall provide the optimal limitation of high or low frequency simultaneously in both ac systems based on pre-set values of proportional gain in each ac system. The proportional gains may be different for over- and under-frequency or adaptive, depending on the magnitude of frequency variation. It shall be possible to limit the contribution of the frequency stabilizer to the power transfer order of the HVdc link. After rapidly responding to arrest frequency changes in the two ac systems under proportional control, the frequency stabilization controls shall behave as frequency controller with individual dead-bands and droop characteristics in each ac system. The priority, gains, droops, speed of response and on/off settings of these droop controllers shall be individually controllable for each end of the link. Separate droop setting values may be required for over- and under-frequency in each system. The facility to initiate automatic arming/disarming of the frequency stabilization controller, based on monitoring of external signals such as power transfer in another circuit, shall also be provided. The Contractor shall determine through a study, the optimal frequency controller structure and parameters that will satisfy the NSPML's frequency deviation requirements during extreme contingencies.

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Automatic AGC control – Provided there is capacity in the LIL HVdc link to provide variable dispatch to meet needs in Nova Scotia, the Maritime Link shall be designed to accept ramp-up and ramp-down signals from AGC controllers in Nova Scotia. The AGC signal will also need to be provided to the LIL so that the necessary power can be obtained from Labrador. The ramp rates shall be adjustable from 0 to 50 MW/min by the operator. Operator adjustable limits on the amount that the AGC can vary the power transfer set-point of the link shall also be provided. The complete design of the AGC system shall be coordinated with the design of the AGC in Newfoundland and AGC capability of the LIL.

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Request IR-192:

With reference to Appendix 3.01, page 76:

(a) What is the current status of developing the additional details of the performance requirements?

(b) Provide the additional details if they are available.

Response IR-192:

(a) AC and DC system studies have been completed and all functional and performance requirements for the converters have been established based on the system studies. Draft *Technical Specifications for Converters* are in progress and are scheduled for completion by the end of March 2013. These specifications will be included in the RFP to solicit proposals from vendors for fixed-price EPC contracts.

(b) Further details are not available at this time, as the technical specifications have not been finalized. Conceptually, the technical requirements correspond to those presented in the mini-specification included with Hingorani IR-10, except for the requirements for Black Start Capability and for spare converter transformers at each converter site.

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Request IR-193:

With reference to Appendix 3.01, page 76, please specify what margins and level of redundancy of the valves' components are considered sufficient to ensure that faults on the DC line do not result in a requirement to perform unscheduled maintenance on the valves.

Response IR-193:

The valve component redundancy is not related to the dc fault performance of the link. The specifications are under development, and will call for a specified percentage level of redundancy in the I GBT valves to cover for component failures between the scheduled maintenance events.

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Request IR-194:

With reference to Appendix 3.01, page 76, please provide any reports, studies, reviews, or other materials with the analyses of the industry statistics related to the based on VSC technology HVDC converter valve groups and their cooling systems, including aging evaluation, forced outage rates, reliability in service, failure modes, etc. To the extent a report is subject to the strict copyright laws (e.g., a CIGRE report) please provide a summary of the report observations and conclusions.

Response IR-194:

There are limited statistics collected for the VSC based HVdc systems yet, although there is a protocol established for data collection. Many of the components of the VSC HVdc systems are similar to the LCC HVdc systems with the exception of valves and phase reactors, therefore the available statistics for LCC HVdc as it relates to components (for example, converter transformers) can be helpful. CIGRE has collected the reliability statistics for a large number of HVdc links with reports available to the CIGRE members.

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Request IR-195:

With reference to Appendix 3.01, page 77:

(a) Please provide the target reliability performance levels for the Maritime Link system, including but not limited to the (1) maximum number of pole forced outages per year; (2) maximum number of bipole forced outages per year; (3) maximum forced energy unavailability; (4) maximum scheduled energy unavailability; (5) minimum duration between scheduled pole maintenance outages.

(b) Explain whether there is any correlation of the target reliability performance levels and the requirements specified in the upper paragraph on page 83.

Response IR-195:

(a) From the mini-spec provided under Hingorani IR-10:

(i) Maximum of 5 forced pole outages per year
(ii) Maximum of 0.1 forced bipole outages per year
(iii) Maximum forced energy unavailability of 1.0 percent
(iv) Maximum scheduled energy unavailability of 1.5 percent
(v) Minimum duration between scheduled pole maintenance outages of 1 year

(b) Yes.

Request IR-196:

With reference to Appendix 3.01, page 77:

(a) Please provide a copy of all guarantees and warranties required from the converter supplier with regard to the forced outage rates and energy unavailability resulting from failures of the supplier's equipment.

(b) Would the supplier be held responsible for the consequential damages, including the replacement power costs? Under what circumstances, if any, would the supplier be held responsible for consequential damages?

(c) What is the warranty period for the supplier's equipment?

Response IR-196:

(a) Guarantees and Warranties

(i) The equipment supplier shall provide guarantees and warranties to fulfill the following Energy Availability (EA) requirements.

- If the annual Energy Availability (EA) is below the guaranteed value of ≥98 percent, for any year, the guarantee period shall be extended for a one year period for a maximum of three years.

- If at the end of the guarantee extension period, the Energy Availability (EA) in the best three years (out of a total period including extended year(s)) is ≥98 percent; the Energy Availability (EA) guarantee shall be considered fulfilled.

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- If the annual Energy Availability (EA) is not fulfilled, the Contractor shall correct all design deficiencies and equipment defects at its sole expense and at no cost to the Purchaser.

- After correction of such deficiencies and defects, if the average annual energy availability (EA) calculated over the two-year period is ≥98 percent, (excluding the previous years and the period for correcting the deficiencies), and then the energy availability guarantee shall be considered fulfilled.

(ii) For fulfillment of the Forced Energy Unavailability (FEU), the following shall apply:

- If the FEU is greater than the guaranteed value of 1 percent in any year, the guarantee period shall be extended for a one year period for a maximum three years.

- If at the end of the guarantee extension period, the FEU in the best three years (out of a total period including extended year(s)) is ≤1 percent; the FEU guarantee shall be considered fulfilled.

- If the FEU value is not fulfilled, the Contractor shall correct all design deficiencies and equipment defects at its sole expense and at no cost to the Purchaser.

- After correction of such deficiencies and defects, if the average annual FEU calculated over the two year period is ≤1 percent, (excluding the previous years and the period for correcting the deficiencies), and then the FEU guarantee shall be considered fulfilled.

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(b) Commercial terms associated with the Guaranties and Warranties have not yet been finalized.

(c) The warranty period is 36 months after the in-service date of the facilities, plus any valid extension described in Part (a) above.

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Request IR-197:

With reference to Appendix 3.01, page 77:

(a) Who exactly will be responsible for monitoring the Maritime Link converters' performance for the initial 3 years of operation?

(b) What would be the scope of these monitoring activities?

(c) Will anybody continue to monitor the converters' performance after 3 years of commercial operation?

Response IR-197:

(a) Performance guarantees will be in place for the first three years of commercial operations and monitoring will be completed by both ENL and the Converter Supplier.

(b) The scope of the monitoring activities will include:

- Guaranteed availability and reliability values for Forced Outage Rate, Energy Availability, Forced Energy Unavailability, and Scheduled Energy Unavailability
- Guaranteed Failure Rates of the Insulated Gate Bipolar Transistors Modules, Anti-parallel Diodes, and Valve Capacitors
- Guaranteed Loss Values

(c) Yes. Monitoring will continue for the life of the facility.

Request IR-198:

With reference to Appendix 3.01, page 77, please identify possible mitigating measures to improve performance if the guaranteed values are not met and specify who will be responsible for the costs associated with the mitigating measures' implementation.

Response IR-198:

The specification requires an Energy Availability (EA) of 98 percent or better and Forced Energy Unavailability (FEU) of less than 1 percent for fulfill:

- If the annual energy availability (EA) is below the guaranteed value of ≥98%, for any year, the guarantee period shall be extended for a one-year period for a maximum of three years.

- If, at the end of the guarantee extension period, the energy availability (EA) in the best three years (out of a total period including extended year(s)) is ≥98%, the energy availability (EA) guarantee shall be considered fulfilled.

- If the annual energy availability (EA) is not fulfilled, the Contractor shall correct all design deficiencies and equipment defects at its sole expense and at no cost to the Purchaser.

- After correction of such deficiencies and defects, if the average annual energy availability (EA) calculated over the two year period is ≥98%, (excluding the previous years and the period for correcting the deficiencies), then the energy availability guarantee shall be considered fulfilled.

If the EA requirements are still not met, the conditions set in the Commercial part of the RFP will apply. These conditions have not yet been finalized.

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Request IR-199:

With reference to Appendix 3.01, pages 80-81, please explain whether and, if so, why not aspare converter transformer is required neither at Bottom Brook nor at Woodbine.

Response IR-199:

A spare converter transformer is proposed for both the Bottom Brook and Woodbine converter stations.

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Request IR-200:

With reference to Appendix 3.01, pages 80-81:

(a) Please provide any reports, studies, reviews, or other materials with the analyses of the industry statistics related to the HVDC converter transformers, including aging evaluation, forced outages' rates, reliability in service, failure modes, etc.

(b) To the extent a report is subject to the strict copyright laws (e.g., a CIGRE report) please provide a summary of the report observations and conclusions.

Response IR-200:

(a) See Part (b) below.

(b) Summary of Available Reports.

Cigre publishes confidential semi-annual survey reports that provides information on forced outages associated with AC equipment and auxiliaries (Category AC-E) and other components of an HVdc converter facility, including outages associated with some of the converter transformer failures. The reports cover two-year periods commencing in odd-numbered years. And the last report was issued in 2012 for the period 2009-2010. Although the reports only cover LCC installations to date, some of the findings are instructive, and there is little reason to believe the results will differ in regard to converter transformers.

The general findings from these reports are that the AC-E category of equipment consistently makes up more than 80 percent of the Forced Energy Unavailability (FEU) in converter stations, and that the converter transformers themselves constitute a significant share of the FEU of the AC-E equipment group.