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Request IR-126:

Regarding NSPML/NSPI responses to UARB IR-3 and IR-22(a)

(a) What is the basis for the statement that the NS Block could not be delivered reliably without the construction of the Granite Canal to Bottom Brook AC line (excluding any consideration of energy in excess of the NS Block)? Please provide any documentation prepared to reach this conclusion.

(b) What incremental transmission service charges would be possible, but for the construction of the Granite Canal to Bottom Brook AC line?

Response IR-126:

(a) Please see response to CA/SBA IR-316

(b) Please see response to NSUARB IR-127.

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Request IR-127:

With respect to part (b) of the response to UARB IR-3, please clarify

(a) Which three circuits are carrying energy to the ML entry point – i.e. where are their other terminal points?

(b) Please describe what constitutes "the remaining system" which is available to deliver the NS Block.

(c) If the 230kV line Granite Canal – Bottom Brook were not built, would there be "incremental transmission service charges" for delivering the NS Block?

Response IR-127:

(a) The three circuits that will transmit power to the Bottom Brook 230-kV bus are:

- TL211, originating at Massey Drive
- TL233, originating at Buchans
- New 230-kV circuit, originating at Granite Canal

(b) One 230-kV circuit connects Massey Drive to Buchans. Two 230-kV circuits connect Buchans to Stony Brook, and two 230-kV circuits connect Stony Brook to Bay d'Espoir. From Bay d'Espoir, two 230-kV circuits connect to Sunnyside, and two 230-kV circuits connect Sunnyside to Western Avalon. Two 230-kV circuits connect Western Avalon to Hollyrood.

(c) The Granite Canal to Bottom Brook line is being built for reliability reasons, and is a necessary component for the delivery of the NS Block. Construction of Granite Canal to Bottom Brook line is an agreed upon component of the commercial arrangements between Nalcor and NSPML. These arrangements require that the Maritime Link be capable of delivering the NS Block as well as the Nalcor export capacity.

REDACTED

Request IR-128:

With respect to NSPML/NSPI response to UARB IR-5, a):

Please provide the current cost estimate for each of the assets to be developed in Newfoundland that have been identified as Roman numerals i-ix.

Response IR-128:

(i) The termination points for the HVDC subsea cable which includes anchor point, about 1 km of buried cable and a transition compound to convert to overhead lines; - [redacted]

(ii) An overland HVDC transmission line from near Cape Ray, to near Bottom Brook - [redacted]

(iii) 500 MW HVDC converter station adjacent to the substation at Bottom Brook - [redacted]

(iv) Expansion of the Bottom Brook substation to accommodate the HVDC lines terminations and the new AC line terminations from Granite Canal, - [redacted]

(v) AC transmission line from Bottom Brook to Granite Canal;-[redacted]

(vi) A low voltage DC overhead line between Bottom Brook and St. Georges Bay connecting the shore grounding facility to the converter - [redacted]

(vii) a shore based grounding facility - [redacted]

REDACTED

(viii) Interconnection of the new AC line at Granite Canal which includes reconfiguration and terminations at Upper Salmon and Bay d'Espoir substations - [redacted]

(ix) Associated communications and control center modifications to accommodate the data and controls for the Bottom Brook converter. - [redacted]

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Request IR-129:

A reference was made in NSPML/NSPI response to UARB IR-5 e), that these investments will improve both Nova Scotia and Newfoundland equally. A review of expected fuel, operating and capital savings reported in UARB IR-77, Attachment 2, p. 3 does not appear to support the statement that the benefit will be equal between the provinces:

(a) Please confirm "proportionate to the investment" is a better explanation for the benefit than equal.

(b) Please provide detail of how the net system benefits in IR-77, Attachment 2, were determined.

(c) Please provide an updated version of the table provided on p. 3 in IR-77, Attachment 2 with current projected information.

(d) The attachment referred to in part b) indicates there will be additional savings if the shutdown of two coal units was achievable. It appears this requirement will be achievable; please include in part b) a line indicating the further savings expected resulting from the shutdown of the two coal plants.

Response IR-129:

(a) The response to NSUARB IR-5(e) states:

> All of the components of the Maritime Link will improve both Nova Scotia and Newfoundland systems equally. It is not practical to parse the benefit of the project due to the 20 For 20 Principle, where all of the assets serve both provinces proportionately.

NSPML agrees that the word "proportionately" is preferable to the word "equally".

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(b-d) NSUARB IR-77 requested "all studies and reports, including internal reports that have been completed or in draft". NSUARB IR-77, Attachment 2 contains a draft study, described in the response as, "a preliminary assessment conducted in early 2010, not a final analysis". The net system benefits in this presentation were calculated by Strategist; the input assumptions are contained on slide two of the presentation. NSPML has not attempted to update this preliminary table, but instead has completed a new and comprehensive analysis; NSPML's Strategist analysis in support of the Application is described in the Alternatives Analysis section of the Application. This analysis incorporates the benefits associated with the reduction in coal-fired thermal generation. NSPML has estimated net savings of $100 million in 2018 associated with reduced coal-fired generation.

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Request IR-130:

The responses to McMaster IR-7 and UARB IR-7 both centre on improved access to alternative markets provided by the ML, however the answers are very different in character. McMaster IR-7 response indicates ML enhances access to markets (i.e. implies multiple additional potential suppliers) in Newfoundland and beyond via Quebec, while the response to NSUARB IR-7 indicates the more modest enhancement of the ML providing access to surplus power in Newfoundland only (i.e access to a single additional potential supplier). Please clarify the discrepancy in these responses by describing what specific new alternatives for purchasing supply and selling surpluses ML provides compared to other options such as reinforced transmission to New Brunswick and points beyond.

Response IR-130:

The response to UARB IR-7 highlights the Maritime Link's ability to enhance access to the new market of Newfoundland and Labrador and as energy flows through the NS/NB intertie, creating a 1-for-1 MW (export to import ratio) which otherwise may have been constrained prior to the Maritime Link. McMaster IR-7 was referencing the strengthening of Nova Scotia's connection to the North American grid, explaining the energy loop created with two means to now import electricity into Nova Scotia. As well, in McMaster IR-7, it was indicated that a second tie between Nova Scotia and New Brunswick does not introduce new market sources of energy.

Also please refer to McMaster IR-24.

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Request IR-131:

Regarding NSPML/NSPI to UARB IR-13 – Table

Please explain why, in general terms, the Maritime Link Loss Rate (MLLR) decreases as a percentage from 2018 to 2037, while the size of the NS Block remains constant over that same period?

Response IR-131:

For the purpose of calculating transmission system losses, conservative energy levels were used without any cross-reference to the demand for energy which resulted from the alternatives analysis, where more surplus energy flows to Nova Scotia than was modeled in the system losses calculation. As the surplus energy flows increase or decrease, system losses will also increase or decrease. The losses as modeled provide a view of how the loss rate for MLLR will change with various levels of surplus energy delivered.

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Request IR-132:

Regarding NSPML/NSPI responses to UARB IR-17, UARB IR-36 (e) and UARB IR-75 (b) and (c); the response to NSUARB IR-17 (b) indicates that no upgrades to the Bayside Generation Station are required as a result of the Nalcor Transactions.

In the September/October 2012 issue of the magazine publication "Earth Resources (Eastern Canada's Energy News)" at page 21, it states that "Halifax-based Emera is looking for investments in its Bayside power plant in Saint John, N.B. but says the plant will not be connected to the New England market it serves. President and CEO Chris Huskilson says the plant will instead serve the Muskrat Falls project, which needs more transmission rights to send power from the Lower Churchill River to Boston. … Huskilson says the 260-megawatt Bayside plant needs a $30 million reinvestment."

(a) Please reconcile the response to UARB IR-17 with the report in the above publication.

(b) Is the $30 million Bayside reinvestment referred to above required under the NBTUA or under any of the other Nalcor Transactions/agreements?

(c) Is any part of the $30 million Bayside reinvestment recoverable from NS ratepayers?

(d) Does the $30 million Bayside reinvestment bear any relation to the estimated $31.5 million cost for the Nova Scotia/New Brunswick intertie asset investment referenced in the response to UARB IR-36 (e)?

(e) Please confirm whether approval is being sought in the present application for the $31.5 million amount noted in UARB IR-36 (e).

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Response IR-132:

(a) There is no inconsistency. The $30 million upgrade at the Bayside plant referenced in the question was performed in 2012 and is not related to the Nalcor Transactions. In 2012, Bayside Power upgraded its gas turbine with an upgrade package which boosted the plant's operating efficiency. No new investment in the Bayside plant is required as a result of this transaction.

(b) No.

(c) No.

(d) No.

(e) Regarding the estimated $31.5 million capital investments, as noted in footnote 57 on page 144 of the Application, two of the three projects were included in the NS Power 2013 ACE spend profile. The third of three projects was included in NS Power's 5-year outlook filed with ACE, because the spend is planned to begin in 2014 if necessary. These items are capital costs to be incurred by NS Power and are included in this Application for completeness. As stated on page 145 of the Application:

> Based on projections of Nalcor Surplus Energy, it is expected that the transmission fees paid by Nalcor (which will be provided to NS Power pursuant to the NS Power-NSPML Agreement) during the term will offset the associated capital expenditures, redispatch costs, and anticipated system maintenance costs resulting from the Nalcor Surplus Energy flowing through Nova Scotia.

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Request IR-133:

Regarding NSPML/NSPI response to UARB IR-18:

What benefits or costs would accrue to NS ratepayers if the NSTUA is renewed for a Supplemental Term of 15 years?

Response IR-133:

As noted in Article 2.7 of the Energy and Capacity Agreement (Appendix 2.03 to the Application), NSPML has an option to enter into a negotiation with Nalcor for a Subsequent Term. NSPML foresees that the benefits could include, but are not limited to, the following:

(a) A source of renewable energy to meet renewable energy standards.

(b) A source of energy to offset any new generation required which may be cheaper than building the needed generation in Nova Scotia

(c) Possibility of a fixed-price, long-term contract that may not be subject to volatility of fossil fuel prices.

Since it is NSPML's option to enter into such negotiation, if the terms are not satisfactory, there is no requirement for NSPML to proceed in such a way that would not be beneficial for NS customers.

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Request IR-134:

With respect to NSPML/NSPI response to UARB IR-19:

There are three options which would see Nalcor acquiring Emera's partnership interest in LIL LP.

(a) Please identify, if none of these options are exercised by Nalcor, will Emera's ownership in the LIL be in perpetuity?

(b) What consideration is Emera paying Nalcor or any other party for their interest in the LIL?

Response IR-134:

(a) If Nalcor does not exercise its option under Section 5.15 (a), (b) or (c) of the NLDA, and Emera does not otherwise transfer its Partnership Interest in the LIL LP, and assuming that the Service Life of the LIL continues, Emera will hold its Partnership Interest for as long as the LIL LP is in existence. The LIL LP will end on December 31, 2081, unless otherwise agreed by the Partners.

(b) Emera's Partnership Interest in the LIL LP is held through ENL Island Link Incorporated, a wholly-owned subsidiary of Emera. In accordance with Section 5.6 of the NLDA, the subscription price for the 25 Class B Limited Units subscribed for by ENL Island Link was $1,000. As a Limited Partner in the LIL LP, ENL Island Link is obligated to contribute to the funding of LIL Development Activities through Cash Calls made by the General Partner. The amount of ENL Island Link's funding obligation is set out in Section 5.8 (a) (i) of the NLDA.

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Request IR-135:

Further to NSPML/NSPI response to UARB IR-21,

(a) Please provide a table showing how 170 MW of import capacity from Muskrat Falls (less 17 MW of losses), plus the supplemental block of off-peak energy, will enable NSPI to retire two coal-fired units at Lingan with a net rating of 310 MW. The table should show the specific dates as well as the amount of capacity and energy being imported or displaced during each year.

Response IR-135:

Please refer to SBA IR-243 Attachment 2 for the load and resource adequacy assessments for each alternative under high and low load including unit retirement forecasts. The Maritime Link allows for the retirement of a second Lingan unit before 2020. The retirement of the first Lingan unit is the same period in each alternative.

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Request IR-136:

Further to NSPML/NSPI response to UARB IR-23 (a),

(a) Please provide a table showing the capacity and energy flows along the Sydney to Truro transmission corridor during each of the 35 years.

(b) Please explain the renewable generation levels of "260 MW plus pending COMFIT".

(i) What amount of pending COMFIT, in capacity and energy, is being referenced in this response?

(ii) Does the 260 MW and the pending COMFIT refer to rated output or does it refer to an assumed capacity factor? If the latter, what is the CF assumed throughout various periods of the year and various periods of the daily demand cycle?

(iii) Please distinctly identify which "other transmission upgrades" are needed to support prospective power wheeling requirements, and which upgrades are needed to support renewable generation, along the corridor between Sydney and Truro. Respective costs associated with each of these categories are also requested.

Response IR-136:

(a) The Optional System Impact Study provided as McMaster IR-2 Confidential Attachment 1 studied expected system conditions for 2017. Detailed modeling of the transmission system is conducted for the most constrained system conditions since the criteria to be applied is deterministic, as opposed to energy adequacy studies which are probabilistic. The three tables of Appendix A of McMaster IR-2 Confidential Attachment 1 list 53 base case flow conditions representing various load levels and dispatch conditions. Capacity (MW) flow is not a constant across the Sydney to Truro route, flows vary on the transmission system as there is both generating sources and customer load extracted or injected at the various substations (Woodbine, Port Hasting, Hopewell namely). Flow across the backbone varies on a minute by minute basis throughout the year. The referenced tables show flow at points designated as Cape Breton Export (CBX) and Onslow Import (ONI). A demonstration of the wide variations of CBX flow for the select years studied in PLEXOS is shown in CA/SBA IR-94 Attachment 1. Please see Synapse IR-11 Attachment 4 for energy flows by month for the years 2015 through 2040.

(b) (i) It is assumed that approximately 67 MW of COMFIT generation will be installed east of Onslow.

(ii) Transmission System Impact Studies are deterministic and must be conducted at full rated output of the wind farm. Please refer to Section 3.2.1.2 and Section 3.2.2.2 of the Standard Generator Interconnection Procedures (GIP)[1] approved by the Board on February 10, 2010.

(iii) The "other transmission upgrades" are identified in Figure 8.1 on page 144 of the Application. These upgrades support the prospective power wheeling arrangements assuming that existing renewable generation is not curtailed to facilitate the wheeling transaction. The upgrades facilitate existing and new renewable generation, particularly north and east of Onslow, when the Maritime Link is not operating at full rated load. The associated transmission upgrade costs are necessary to support the Maritime Link. The benefits for renewable generation are not required all of the time, so it would be very difficult to allocate respective costs since the costs must be incurred for the Maritime Link, and the benefits to renewable generation are a spin-off of those transmission reinforcements.

[1] http://oasis.nspower.ca/site-nsp/media/Oasis/RevisedGIPFeb102010.pdf

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Request IR-137:

Further to NSPML/NSPI response to UARB IR-23 (b),

(a) Please elaborate on the statement that "Upgrades to the other parts of the transmission system facilitate existing/proposed renewable generation in displacing fossil generation on the east end of the NS system."

(i) Please specify the upgrades and associated costs being referenced.

(ii) Are all of those upgrades needed to accept the 170 MW Nova Scotia block? Please explain.

(iii) If any of those upgrades are needed to accommodate existing/proposed renewable generation other than the 170 MW from Muskrat Falls, please identify those upgrades along with their associated costs and explain their inclusion in the Maritime Link application.

(b) NSPML states that NSPI customers will receive benefit from transmission revenues associated with power wheeling as discussed on lines 4 - 18, page 145 of the Application.

(i) Please confirm that lines 14 - 17 also imply that if the revenue from the Nalcor transmission fees does not fully recover capital, re-dispatch, and system maintenance costs, then NSPI ratepayers will be responsible for those unrecovered costs.

(ii) If confirmed, does NSPML consider this to be a benefit to NSPI ratepayers?

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Response IR-137:

(a) (i) Please refer to Figure 8.1 on page 144 of the Application.

(ii) These upgrades are not required to accept the 170 MW NS Block. These Network Upgrades were identified in studies conducted for the Long Term Firm Point-to-Point Transmission Service under the terms of the NS Power Open Access Transmission Tariff (please refer to CA/SBA IR-121). The System Impact Study associated with this Transmission Service Request is in progress.

(iii) As explained in NSUARB IR-136(b)(iii), these Network Upgrades are not necessary for other renewable generation, but provide potential benefit to other renewable generation when the Maritime Link is not scheduled at full load. Today, without the Network Upgrades associated with the Maritime Link, potential transmission congestion associated with existing renewable generation is managed through out-of-merit generation dispatch, as described in response to CA IR-89.

(b) (i-ii) Please refer to UARB IR-60 and PC IR-17. The Company expects that over the life of the project costs will be fully recovered. Ratepayers will benefit from the Maritime Link project through the opportunity to access market priced renewable energy.

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Request IR-138:

With respect to NSPML/NSPI response to UARB IR-25 related to Vegetation Management costs:

Please provide an estimate of operating and maintenance costs associated with the assets physically located in Newfoundland and provide the scheduled occurrence.

Response IR-138:

The annual O&M cost projections contained in the Financial Model are at a screening level and will continue to be refined between now and when the Project begins operation (expected in 2017). The costs are not broken down between Newfoundland and Nova Scotia at this time. The costs presented in the Financial Model are materially accurate in relation to the total Project costs.

Please also refer to response to SBA IR-321.

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Request IR-139:

Regarding NSPML/NSPI response to UARB IR-27:

Are the insurance costs included in the O&M costs projected in the Application? If so, please describe them.

Response IR-139:

Please see response to NSUARB IR-138. The O&M projections provided in the Financial Model encompass all anticipated insurance costs, including those for subsea cable, during the operations phase consistent with the coverage described in the latter part of UARB IR-27.

Please also refer to response to SBA IR-321.

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Request IR-140:

With respect to NSPML/NSPI response to UARB IR-30:

A breakdown of "other costs" is offered from Figure 4-1, Maritime Link Cost Estimates. Part V of the response indicates of the approximately $195 million in "other costs", $68 million is allocated for "Escalation of costs of the project":

(a) Please provide a further breakdown of the "Escalation of costs of the project".

(b) Is the $68 million for "Escalation of project costs" the estimate for the total cost of the project or related to just "Other costs"?

Response IR-140:

(a) The "Escalation of costs of the project" of $68 million is the sum of escalation in all Project costs from the time the estimate was made until the period the expenditure is expected to occur. The breakdown of these costs by category is as follows:

Transmission assets [redacted]
Converter stations and related infrastructure [redacted]
Marine [redacted]
Project management and Other costs [redacted]
Total $68 million

(b) It represents the escalation of the various line items for the total cost of the Project.

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Request IR-141:

With respect to NSPML/NSPI response to UARB IR-30, part a):

"Project Management" is broken down to cost $57 million for Project Management labour related costs and $28 million for General administration, Office, Travel, IT, Legal and other.

(a) Does any of the $85 million for "Project Management" reflect escalation for project management costs?

(b) If not, please explain.

Response IR-141:

(a) No.

(b) Escalation costs, while determined on a cost by cost basis, are accumulated in one line in the total capital cost estimate – see response to NSUARB IR-140.

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Request IR-142:

With respect to part (c) of the response to UARB IR-32, please confirm whether Nalcor or NS Power will own the HVDC converter station at Woodbine when ML assets are transferred by NSPML.

Response IR-142:

Nalcor will own the HVDC converter station at Woodbine when the Maritime Link assets are transferred by NSPML.

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Request IR-143:

Regarding NSPML/NSPI response to UARB IR-33:

In the event the actual DG3 Project Costs (including an approved variance) were to exceed the costs approved by the Board, please confirm such excess costs would not be recoverable from NS ratepayers.

Response IR-143:

In the unlikely event that the Project costs exceed the cost estimate approved by the Board in this proceeding (including a variance), NSPML can confirm that recovery of such excess costs would require the approval of the Board, as contemplated by subsection 6 (3) of the Regulations, before they could be recovered from Nova Scotia customers. NSPML will have to demonstrate the prudency of such costs in any such application for recovery.

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Request IR-144:

With respect to NSPML/NSPI response to UARB IR-37, attachment 1:

Please provide the buildup of the revenue requirement provided in each year under each scenario.

Response IR-144:

In Attachment 1 to UARB IR-37, the annual revenue requirement for NSPML is as presented on line 5 of the tab titled “Figure 4.4”. This is the revenue requirement that is also presented in the Financial Model and includes the revenues required for NSPML to recover its capital, O&M, ROE, taxes and related costs.

Line 10 of the same tab of Attachment 1 noted above reflects the annual revenue requirement relating to the surplus energy that NS Power is forecasted to have access to because of the Maritime Link Project. The surplus energy amounts are outputs from the Strategist model. Strategist takes the input data, executes the run and produces the output results.

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Request IR-145:

With respect to NSPML/NSPI response to UARB IR-39, the answers to parts (a), (b), and (c) seem to be inconsistent with the answer to part (d). At issue is whether the transmission in both Newfoundland and Nova Scotia including both LIL and ML were planned as a single optimized project such that cost has been minimized for LIL and ML combined. The response to part (d) indicates that this was so but (a), (b) and (c) discuss only factors relating to meeting Newfoundland needs optimally. If that was the case, then there is a chance that the overall LIL plus ML (i.e. the 100% of which NSPML's share would be 20%) is not as cost effective as it could be. The fact remains that the transmission proposal appears to move ML energy all the way across Newfoundland twice rather than using a more intuitively obvious and direct route.

(a) Please clarify the process by which the proposed transmission arrangements in Newfoundland were planned to be the most cost effective and at what point in the planning process provisions for ML began to be considered.

(b) Please confirm whether or not NSPML personnel were involved in the overall planning of LIL and ML combined and their integration with the existing Newfoundland system.

(c) If NSPML personnel were involved as in (b) above, please describe both the type and level of that involvement.

Response IR-145:

(a-c) Please refer to UARB-IR-39 and Synapse IR-24. After it had been determined that a multi-terminal transmission system, which was configured to accommodate the larger project at Gull Island, was not the preferred solution, NSPML and Nalcor discussed the more appropriate size of the project based upon Muskrat Falls and a smaller interconnection sufficient to deliver energy to displace Holyrood plus export energy to Nova Scotia. The timing was mid-2009.

Nalcor, through NLH, was the party responsible for the determination of the best point of interconnection of the LIL and NSPML was responsible for determining the best point of interconnection for the Maritime Link in Nova Scotia and parties worked together to determine the best point of interconnection for the Maritime Link in Newfoundland. Each system operator was responsible for their own system studies and participated in the joint system studies undertaken for the Maritime Link.

Combined system economic analysis was completed jointly by the parties in 2010.

Nalcor and NSPML were involved in the selection of the final configuration of LIL and ML, and with the approval of the Term Sheet in November 2010, the Basis of Design was included for all project elements at that time.

The UARB IR-39 (b) asked about the optimization relative to the justification of moving power to be delivered to Nova Scotia from west to east all the way across Newfoundland and all the way back again. In NSPML response, we clarified that power will not actually flow as described based upon the integrated system design which was finalized. Based upon integrated system studies with the LIL and ML as configured, the Newfoundland system operates more efficiently in the delivery of power to the ML.

The 20 For 20 Principle ensures both NSPML and Nalcor share the cost and benefits of the optimized integrated systems proportionately. This configuration is the basis of the agreements and the Application, which include the use of the Newfoundland system without additional transmission costs.

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Request IR-146:

Regarding NSPML/NSPI response to UARB IR-40(b), (c) and (d) (IV):

(a) The answer to UARB IR-40(d) (iv) was not completed. Please confirm whether NL ratepayers are making any contribution to the costs of the infrastructure from the Labrador Island Link to Soldier's Pond.

(b) What are the costs of the infrastructure from the Labrador Island Link to Soldier's Pond?

Response IR-146:

(a) The Labrador-Island Transmission Link will transmit electricity from the Muskrat Falls generating station to Soldier's Pond on the Avalon Peninsula near St. John's. It is part of LCP Phase I so NL ratepayers are paying 80 percent of the costs.

(b) At Decision Gate 3, Nalcor has estimated the capital cost of the Labrador-Island Transmission Link to be $2.6 billion.

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Request IR-147:

Further to NSPML/NSPI response to UARB IR-43 (a),

(a) Please identify the amount of energy from Pt. Lepreau that was considered for each year of the "Maritime Link and Other Import Alternatives".

(b) Were any discussions held regarding a potential long-term PPA related to Pt. Lepreau? Please provide details of any such discussions or explain why this was not pursued.

Response IR-147:

(a) In the Maritime Link Alternative, the model was allowed to import up to 100 MW of economic energy from New Brunswick. In the Other Import Alternative, the model was allowed to import up to 500 MW less the Firm Import, of economic energy from New Brunswick. The model determines how much and when it is economical to purchase the energy. Energy from Pt. Lepreau would be one of the potential sources for these imports from New Brunswick. No specific source of economic imports was identified.

(b) No. A PPA related to Pt. Lepreau would not qualify as renewable energy.

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Request IR-148:

Further to NSPML/NSPI response to UARB IR-43 (b),

(a) As requested, please explain why consideration was not given to establishing a new interconnection with New England via southwestern Nova Scotia.

(b) Please explain whether NSPML/NSPI considers that such an interconnection would improve reliability and open additional possibilities for greater market participation regarding imports and/or exports.

Response IR-148:

(a) It was not considered at this time due to the length of the sub-sea cable and the transmission infrastructure required in south-western Nova Scotia. This alternative would require the construction of at least one and possibly two 345 kV ac circuits to the Halifax region. The distance for the subsea HVDC cable would be more than twice the length of the Maritime Link and land transmission would be higher cost ac. In addition to the interconnection Nova Scotia would need access to a new renewable source of energy and capacity from that market.

(b) A new interconnection to New England via subsea cable may improve reliability depending on the location of the interconnection and the system conditions of that market. Although it would give increased access to New England markets it would not increase economic access to Canadian markets due to the export fees out of New England and would not necessarily provide access to new renewable energy sources.

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Request IR-149:

Further to NSPML/NSPI response to UARB IR-43 (c) and SBA IR-70,

(a) **Please provide a copy of the "Screening [which] determined that the economy energy purchased in the Maritimes and New England market via a second 345 kV tie to New Brunswick is more cost competitive than a purchase or build of indigenous wind in Nova Scotia."**

(b) **Please provide all assumptions used in that screening, including all energy costs regarding energy acquisition throughout the 35-year period.**

(c) **Did this screening, or any other analysis, consider the cost benefits that would be available to ratepayers if a hybrid alternative was able to spread expenditures over a 35-year period and thereby avoid ratepayer costs associated with a $1.5 billion investment? If so, please provide that analysis. If not, please explain.**

Response IR-149:

(a) Please refer to Attachment 1, filed Electronically as Excel. The levelized price of the surplus energy for the Other Import Option is $58.70/MWh (2012$) compared to the levelized price of $80/MWh (2012$) for Indigenous Wind, making surplus energy more cost-competitive than wind.

(b) Please refer to Attachment 1, filed Electronically as Excel, which shows the assumed quantities of supplemental energy purchased and associated total $ and $/MWh.

(c) Yes. The transmission investment for a 345 kV interconnection for a hybrid alternative is the same as for the Other Import alternative. The hybrid alternative would include the transmission cost from the Other Import Alternative and contemplates substituting wind

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energy ($80/MWh) for surplus energy ($58.70/MWH) and therefore would not be an economic option for customers. The Maritime Link is a lower cost alternative than the Other Import. The hybrid alternative would be higher cost than the Other Import Alternative.

	OI Base Load Economy Energy Purchases	Purchase Cost at MassHub Pricing)				
	GWh	k$				
			$/MWh	Levelized Price:	$63.54	2016
2015	0.0	$0.0		Discount rate:	6.56%	
2016	0.0	$0.0		Inflation	2.0%	
2017	1241.2	$60,390.3	$48.65	Levelized Price - 2012$	$58.70	2012
2018	2532.2	$122,638.5	$48.43			
2019	2494.3	$124,468.3	$49.90			
2020	2489.7	$129,997.7	$52.21			
2021	2531.2	$137,173.5	$54.19			
2022	2505.2	$141,867.0	$56.63			
2023	2546.3	$147,725.9	$58.02			
2024	2541.0	$150,241.1	$59.13			
2025	2599.5	$158,709.3	$61.05			
2026	2629.1	$164,166.6	$62.44			
2027	2635.8	$167,365.5	$63.50			
2028	2632.1	$170,121.5	$64.63			
2029	2684.5	$177,955.6	$66.29			
2030	2904.7	$202,297.1	$69.65			
2031	2927.5	$206,667.4	$70.60			
2032	2988.8	$216,246.7	$72.35			
2033	3067.2	$226,108.7	$73.72			
2034	3158.2	$241,177.3	$76.37			
2035	3254.6	$256,353.7	$78.77			
2036	3276.3	$264,102.2	$80.61			
2037	3275.6	$268,689.3	$82.03			
2038	3291.4	$275,845.1	$83.81			
2039	3309.8	$282,751.1	$85.43			
2040	3379.0	$299,821.5	$88.73			

NON-CONFIDENTIAL

Request IR-150:

Further to NSPML/NSPI response to UARB IR-43 (d) and UARB IR-16, please expand on your response by specifically stating

(a) Why isn't the 5-Year Supplemental Energy being acquired during years 6 to 35 when emission restrictions are expected to be greater?

(b) Why isn't the 5-Year Supplemental Energy being acquired during peak hours when system requirements would be greater?

Response IR-150:

(a-b) The Supplemental Energy amounts and terms as outlined in the ECA and the Application are the result of negotiations between NSPML and Nalcor regarding timing and volume. The first five years is beneficial for Nova Scotia customers as it reduces NS Power's fuel costs right away. This approach also provides additional time for NS Power to address other components of the generation mix over the long term, keeping in mind that the NS Block delivers 8-10 percent of Nova Scotia system requirements. Also, the supplemental energy is delivered in the winter months which are Nova Scotia's peak season.

In addition, as with all capital investments in a rate base model, the cost to customers on a per megawatt-hour basis is highest at the beginning years due to the fact that the rate base is highest in the early years and gradually decreases as the rate base is depreciated. Acquiring 5-Year Supplemental Energy in the first five years has the advantage of lowering costs to customers on a per megawatt-hour basis in those early years. This impact can be seen in Attachment 1 to NSUARB IR-37, under the tab titled "Figure 4-4". In this tab, on line 6 the amount of electricity received is higher in the first five years (actually spreads over 6 years given the short first year in 2017) due to the Supplemental

Block being received. As a result, the cost per megawatt-hour is lower in the first five/six years than the remaining years as reflected on line 7.

NON-CONFIDENTIAL

Request IR-151:

Further to NSPML/NSPI response to UARB IR-45, please confirm that benefits related to natural gas storage were not included within the analysis of Alternatives. If this was considered, please provide evidence of such analysis.

Response IR-151:

Confirmed. Neither the costs nor benefits related to natural gas storage are included in the analysis of Alternatives.

Request IR-152:

Further to NSPML/NSPI response to UARB IR-49, NSPI's OASIS website lists active transmission interconnection requests of about 565 MW for wind, and active distribution interconnection requests of about 398 MW for wind. NSPML only identifies 216 MW of wind capacity planned or committed for 2015, consisting of 116.5 MW of projects awarded by the REA and the forecasts of 100 MW of COMFIT projects.

(a) Please confirm that NSPML/NSPI is aware that COMFIT projects totaling approximately 144 MW have already been approved by the Minister of Energy.

(b) NSPML/NSPI's response stated that some of the 963 MW of projects in the generation interconnection queue "may be speculative". Please list each of those projects which NSPML/NSPI considers may be speculative.

Response IR-152:

(a) Confirmed.

(b) Only those transmission and distribution projects that appear in the NS Power - Combined T/D Advanced Stage Interconnection Request Queue (http://oasis.nspower.ca/system_report/NSPICombinedInterconnectionRequestQueue.pdf) are considered to be committed projects. These are the transmission interconnection projects that have met the required Progression Milestones of Section 7.2 of the transmission Generator Interconnection Procedures (http://oasis.nspower.ca/site-nsp/media/Oasis/RevisedGIPFeb102010.pdf) or the distribution projects that have met the required Progression Milestones of Section 7.2 of the Distribution Generator Interconnection Procedures (http://oasis.nspower.ca/site-nsp/media/Oasis/DGIP.pdf).

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All Transmission and Distribution projects that have not met the required Progression Milestones are considered to be speculative, as they cannot proceed to the Combined T/D Advanced Stage Interconnection Request Queue until the milestones have been met.

NON-CONFIDENTIAL

Request IR-153:

Further to NSPML/NSPI response to UARB IR-52, please elaborate further on the curtailment of wind energy.

(a) How did NSPML/NSPI use anticipated market conditions to determine that there would be absolutely no opportunity to export renewable wind energy during low load periods?

(b) What capacity factor was modeled within Strategist to reflect curtailment of incremental wind?

Response IR-153:

(a) The estimates made by NS Power revealed that conditions requiring curtailment or export of excess wind energy will occur mostly in the off-peak, low-load, night-time period. Adjacent power systems experience a low load behaviour in the off-peak similar to NS Power's and have large units with relatively low-turndown capability, meaning it is not economic or feasible to two shift or light load the units. As more wind generation is developed in the region, it is anticipated that the number of excess energy events will increase annually. NS Power has had limited success selling into off-peak markets with lower marginal costs than NS Power can deliver, even with capacity backed sources. NS Power does not believe that energy which is being dumped into a market on a regular basis would continue beyond a short period before the market would devalue or even penalize the seller for dumping the energy. This was evident in the New England market in past years where energy prices drop to zero value or negative for some sellers who are required to stay on-line versus being able to shut down in off-peak periods. The product for sale in this consideration would be a non-firm, non-dispatchable energy product that may or may not be available depending upon what actual production occurs.

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(b) It was assumed for the analysis that this circumstance described in (a) above would prevail and non-firm off-peak wind generation sales would be of no value for modeling purposes. For the purpose of the analysis, the decision was taken to assume curtailment.

It is recognized that a curtailed wind generation MW does not contribute to RES compliance. NS Power is not promoting wind curtailment but rather reflecting a possible consequence of high wind penetration. Curtailment is one of many tools that system operators will employ to manage the power system.

It is also acknowledged that export sales contribute to total sales and increase the requirement for renewable energy generation under the RES. So if all excess wind energy was somehow sold or dumped into neighbouring markets, 40 percent of every exported MW would add to the total RES requirement. This has a similar effect, though not as great, as curtailment on the effective capacity factor of incremental wind.

(c) Capacity factors assumed in Strategist modeling for incremental wind projects are as follows:

	Incremental Wind	**Capacity Factor**
Low Load	250 MW	30%
High Load	First 425 MW Additional 50 MW Blocks	35% 32%

NON-CONFIDENTIAL

Request IR-154:

Further to UARB IR-55 (a), NSPML/NSPI responded by referencing Synapse IR-1 Attachment 2, which is a copy of a report prepared by the Renewable Electricity Administrator titled *Review of the Competitive Procurement Process for Renewable Low-Impact Electricity from IPPs*, dated November 6, 2012. However, that report provides no insight into the question being asked in NSUARB IR-55(a).

(a) Please explain the extent of any potential reduction in the $80/MW levelized cost if the 425 MW wind resource was developed by NSPI, not by an IPP.

Response IR-154:

The capital cost needed to achieve a $80/MWh levelized price was calculated based on variable O & M costs of $1/MWh (2011$), $30/kW/year of fixed O & M costs, 62.5 percent debt. 6 percent debt rate, 9.4 percent ROE, 32 percent capacity factor. It was assumed that the plants would be developed by NS Power, so any tax losses generated by the project are assumed to be used within NS Power for the benefit of customers. The capital cost was then calculated so that the levelized price would = $80/MWh. That capital cost is $1985/kW. If the project was developed by an IPP, most likely the cost of capital would be higher and the tax losses would not be available to customers in the year incurred or at all. For clarity, both of these items (higher cost of capital and lost utilization of tax losses) would result in a higher cost for the wind energy.

Please note that the reference in NSUARB IR-55 (a) should have been to CanWEA IR-19 (e). We apologize for the confusion.

Request IR-155:

Further to NSPML/NSPI response to UARB IR-51,

(a) Please provide copies of all correspondence, documentation, notes, and work papers regarding NSPI's meetings with Hydro-Quebec around 2009 which led to its conclusion that "there was no long-term fixed price energy available from Hydro-Quebec".

(b) Please provide copies of all correspondence, documentation, notes, and work papers regarding NSPI's meetings with Hydro-Quebec that were stated to have occurred as recently as January and February 2013 regarding the potential for energy imports. Please identify the dates and the names of participants in those meetings. What were the conclusions?

Response IR-155:

(a) Please refer to Attachment 1 (Hydro Quebec presentation) and Attachment 2 (Emera presentation). There are no other documents, notes, correspondence or work papers. NS Power's conclusion was based upon dialogue, not documentation.

(b) The meetings in January and February 2013 did not include discussion about a long-term fixed-price supply agreement that might provide an alternative to the Maritime Link. As such there are no documents, notes, work papers or correspondence.

The transmission constraints through New Brunswick remain a challenge for energy import alternatives.

Hydro Québec
Production

Une division d'Hydro-Québec

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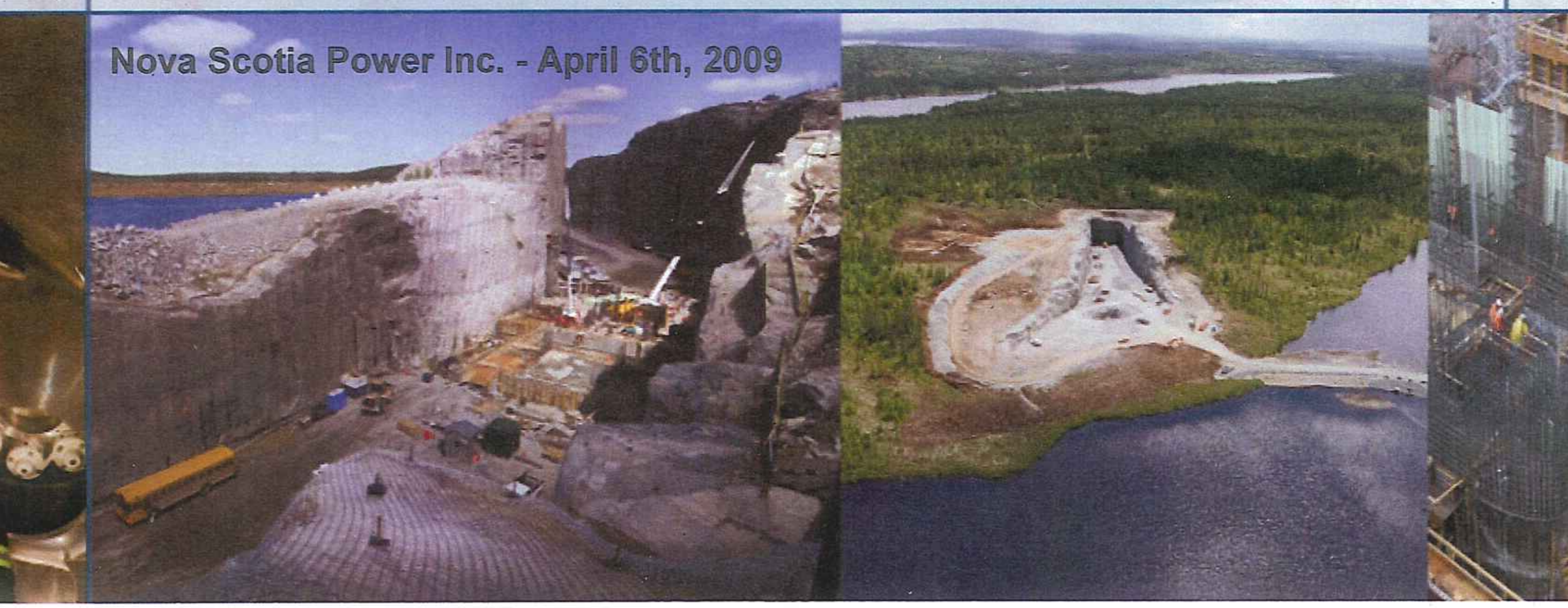
Hydro Québec
Production

How HQUS Could Help North-East United States Meet its Short- and Long-Term Energy Needs

Christian G. Brosseau
President, HQUS



Hydro Québec Production

Hydro-Québec Generates, Transmits and Distributes Electricity

- Assets: **C$65 billion**
- Revenues: **C$12 billion**
- Net income: **C$2.9 billion**

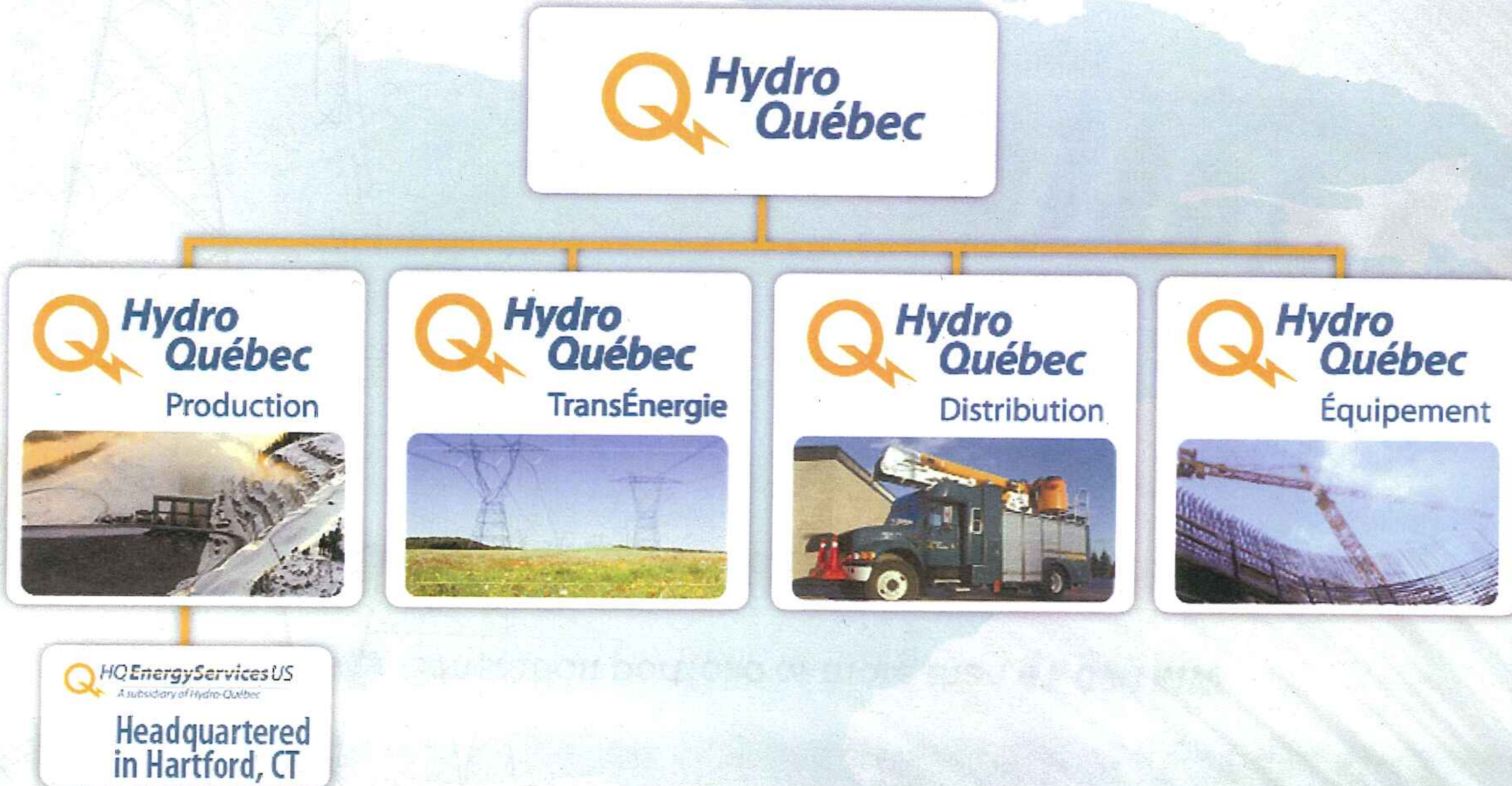
Hydro Québec Production

Hydro-Québec Production

- Generation portfolio of more than **41,000 MW**
- **97%** of it's generation from Hydroelectricity

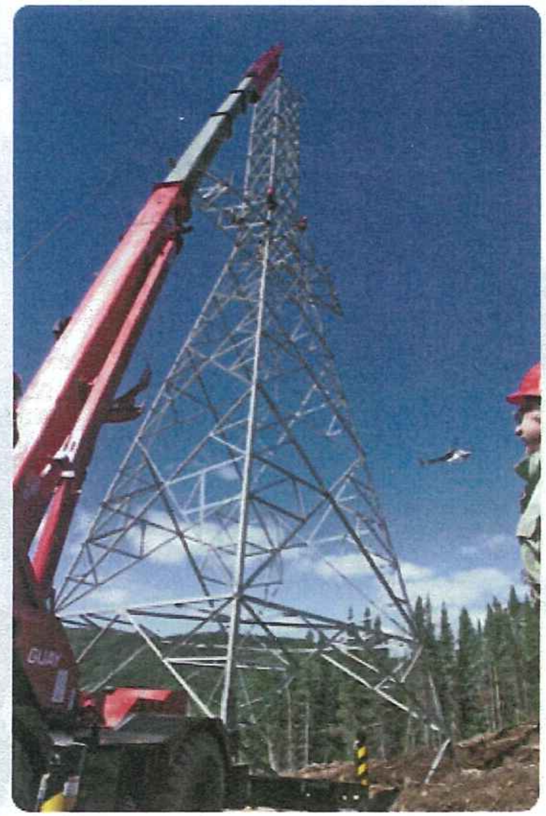
Hydro Québec Production

Hydro-Québec's Divisions



Hydro Québec Production

3 Major Requirements



Socially acceptable

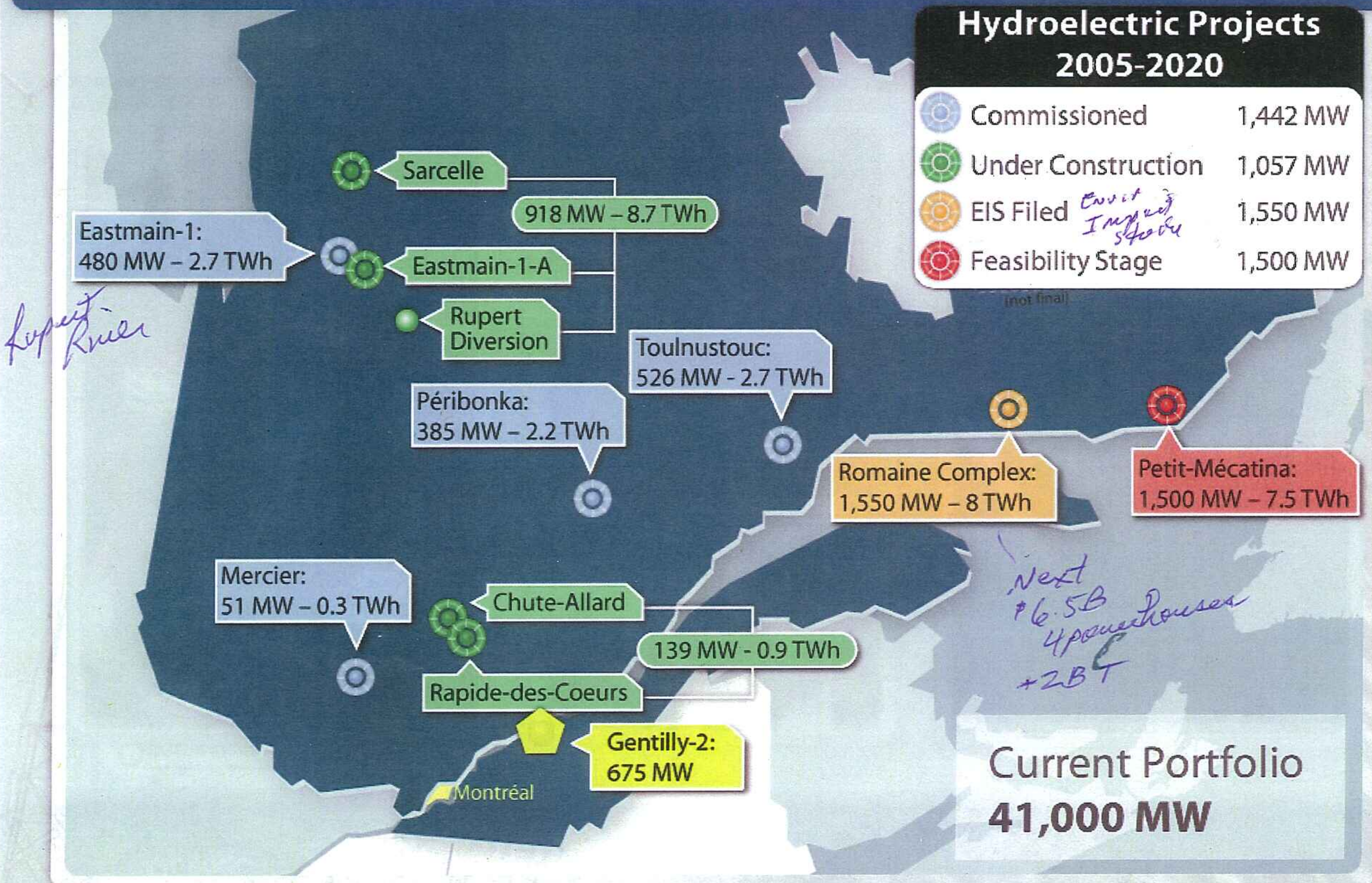
Environmentally acceptable

Economically viable

Blue - last 5 yrs

Hydro Québec Production

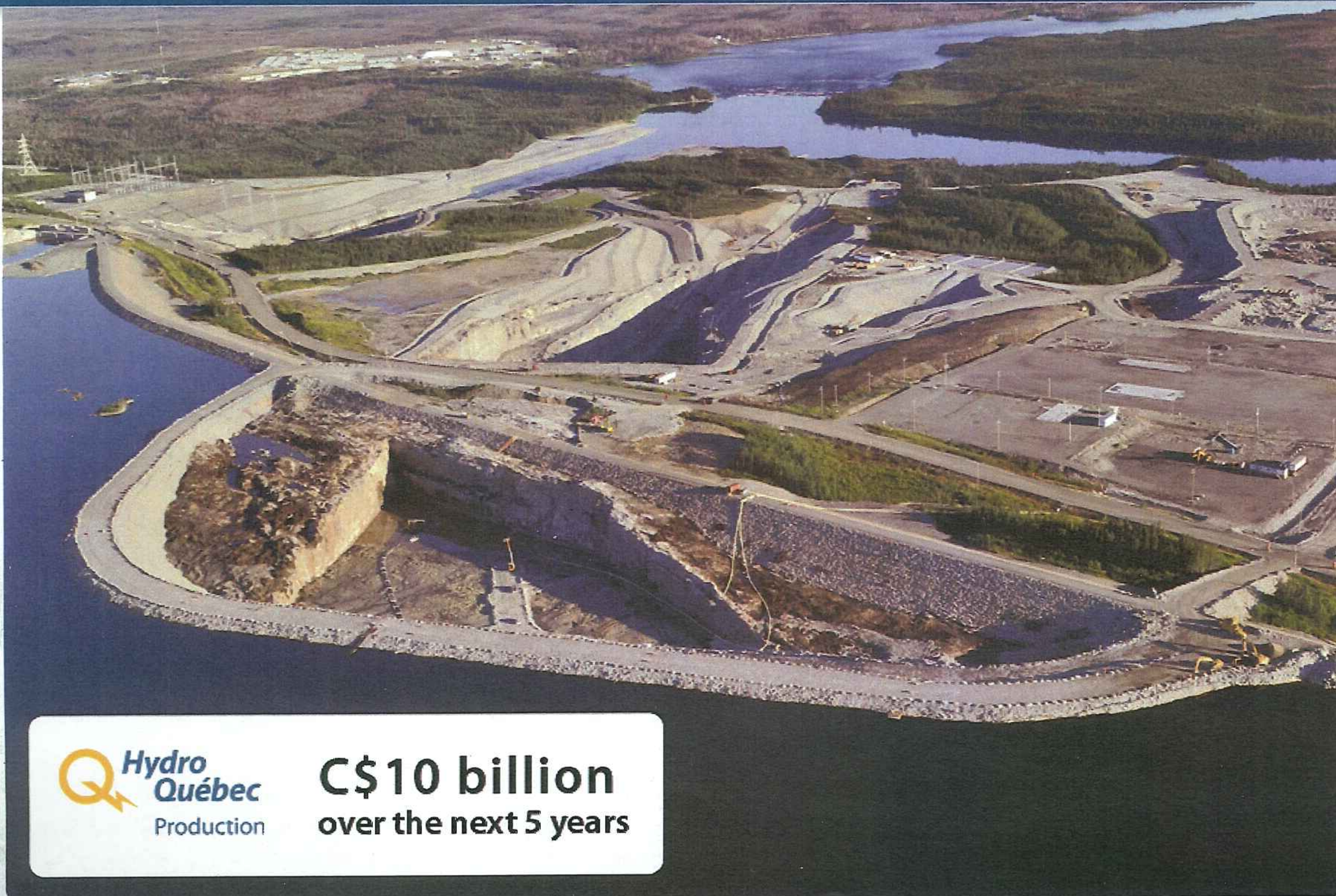
Hydroelectric Development



10B Gen 5+yr

Hydro Québec Production

Investments



Hydro Québec Production

C$10 billion
over the next 5 years

Hydro Québec Production

Wind Power

Hydro Québec Distribution

Two calls for tenders:
3,000 MW to serve Québec's load

Hydro Québec Production

500 MW currently under contract
with independent power producers

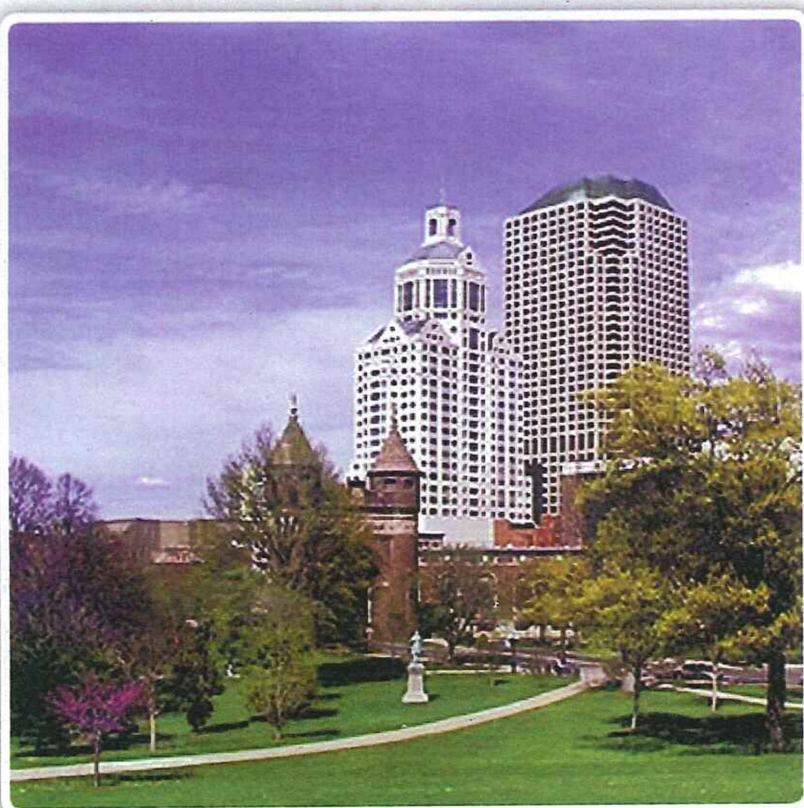
Hydro Québec Production

24/7 Trading Floor

- Since 2000
- Short-term sales 2007 **> 10 TWh**
- Short term annual sales to increase to about **23 TWh**

Hydro Québec Production

HQUS: Hartford, CT.

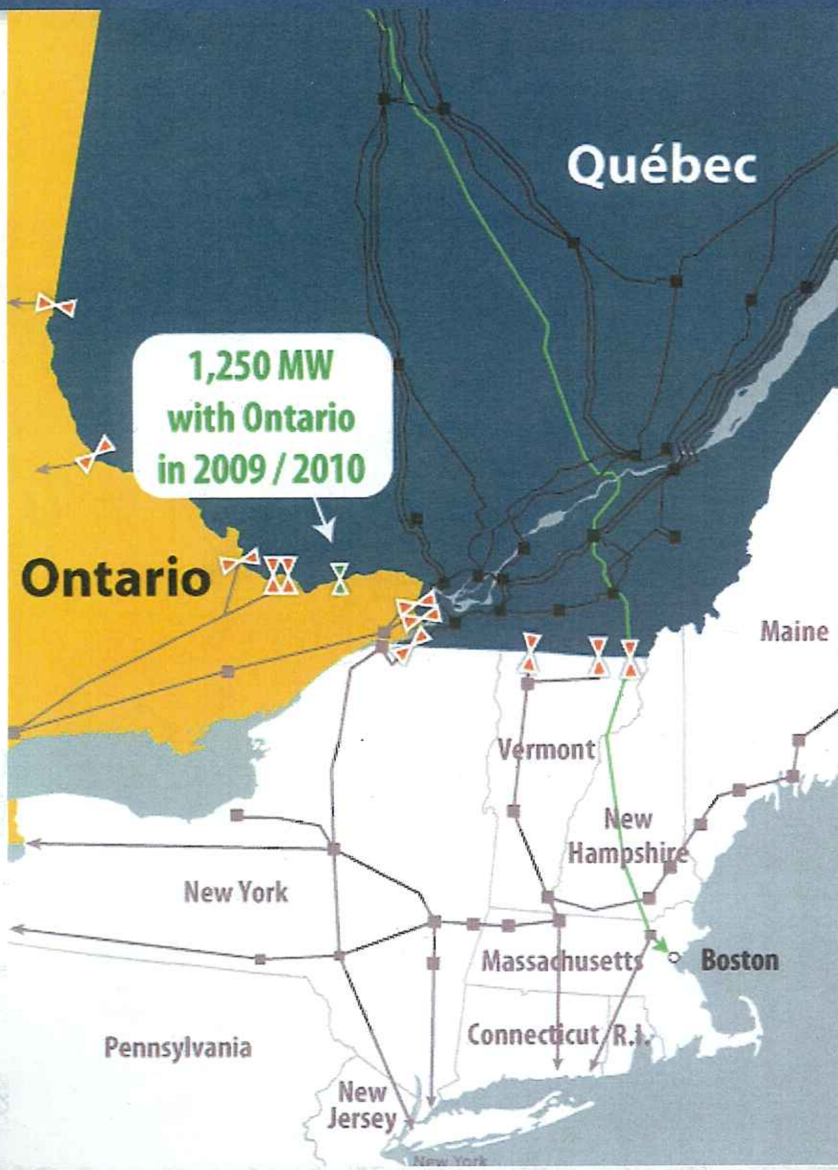


- Originate long-term and structured sales of HQ power in US markets
- Develop and implement HQUS marketing strategy
- Develop and foster key industry relationships
- Perform market analysis and evaluations

IN Canadian but outside Quebec

Hydro Québec Production

Export Markets — MEHQ



$364 M interconnection commissioned in 2 phases : summer 2009 and summer 2010

HQP has purchased the capacity for 50 years

Ontario

HQ

- **Present capacity:**
  Approx. 800 MW
- **Québec - Ontario Interconnection:**
  1,250 MW

Hydro Québec Production

Export Markets — MEHQ

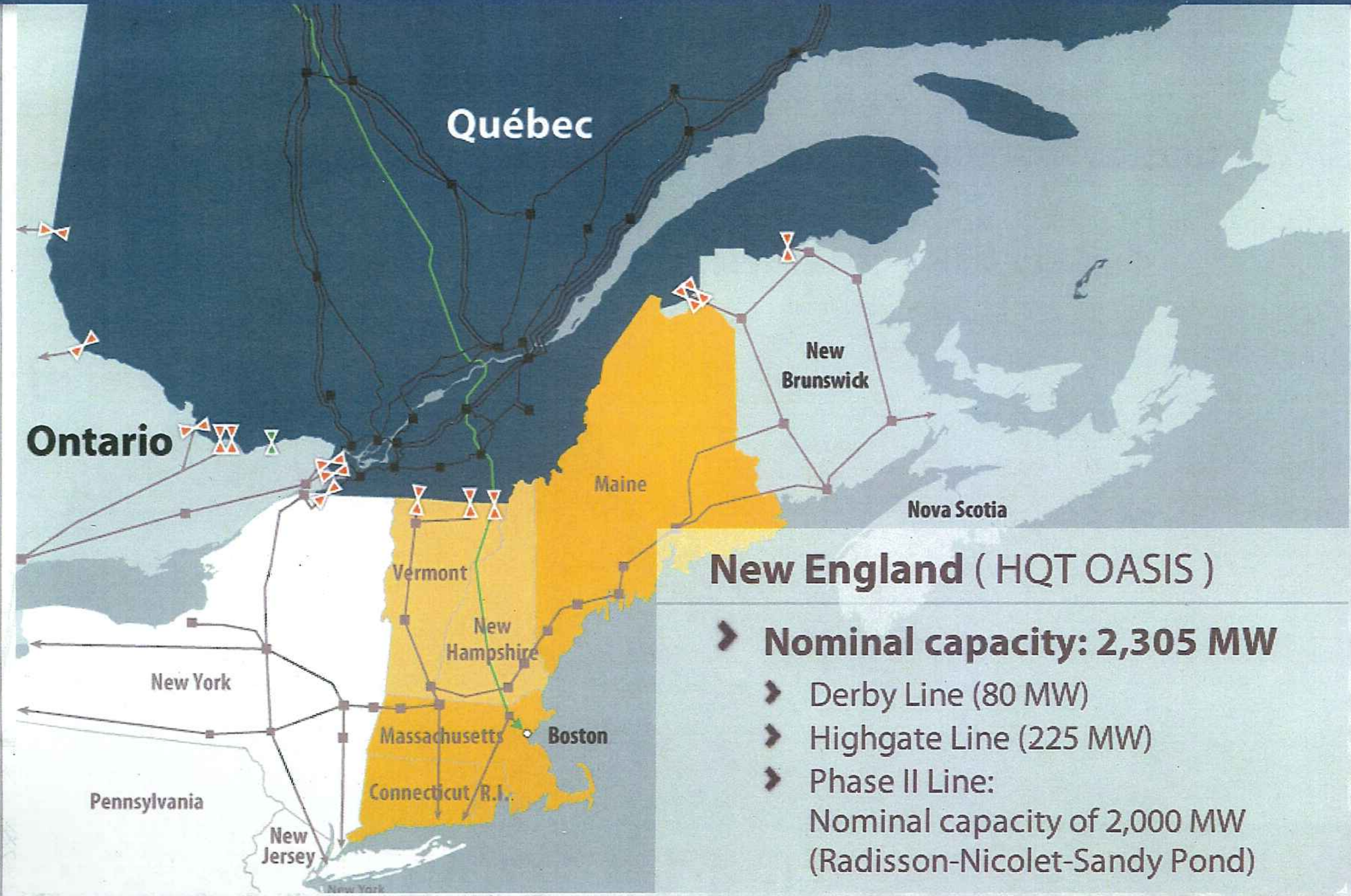
New Brunswick

- Up to 1,200 MW
- Access to the New England Market

+ 300 MW on NRL

Hydro Québec Production

Export Markets — HQUS

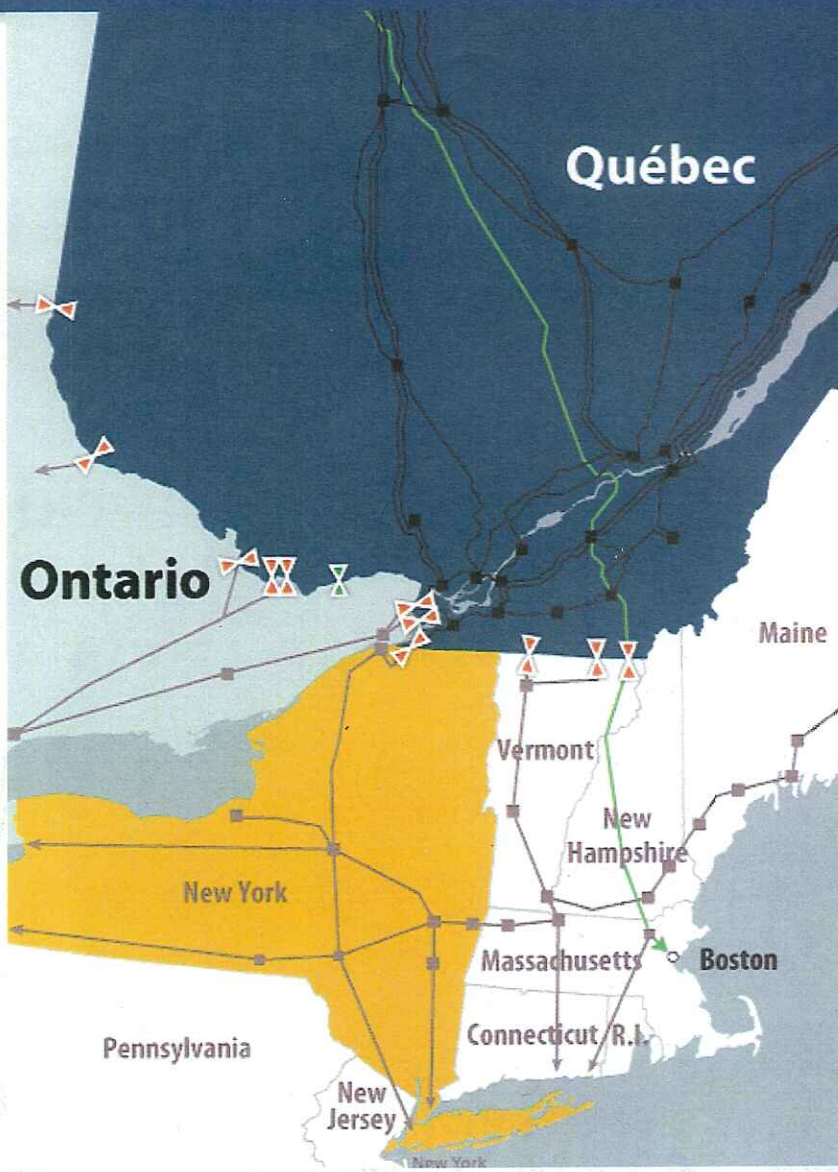


New England (HQT OASIS)

- **Nominal capacity: 2,305 MW**
  - Derby Line (80 MW)
  - Highgate Line (225 MW)
  - Phase II Line:
    Nominal capacity of 2,000 MW
    (Radisson-Nicolet-Sandy Pond)

Hydro Québec Production

Export Markets — HQUS



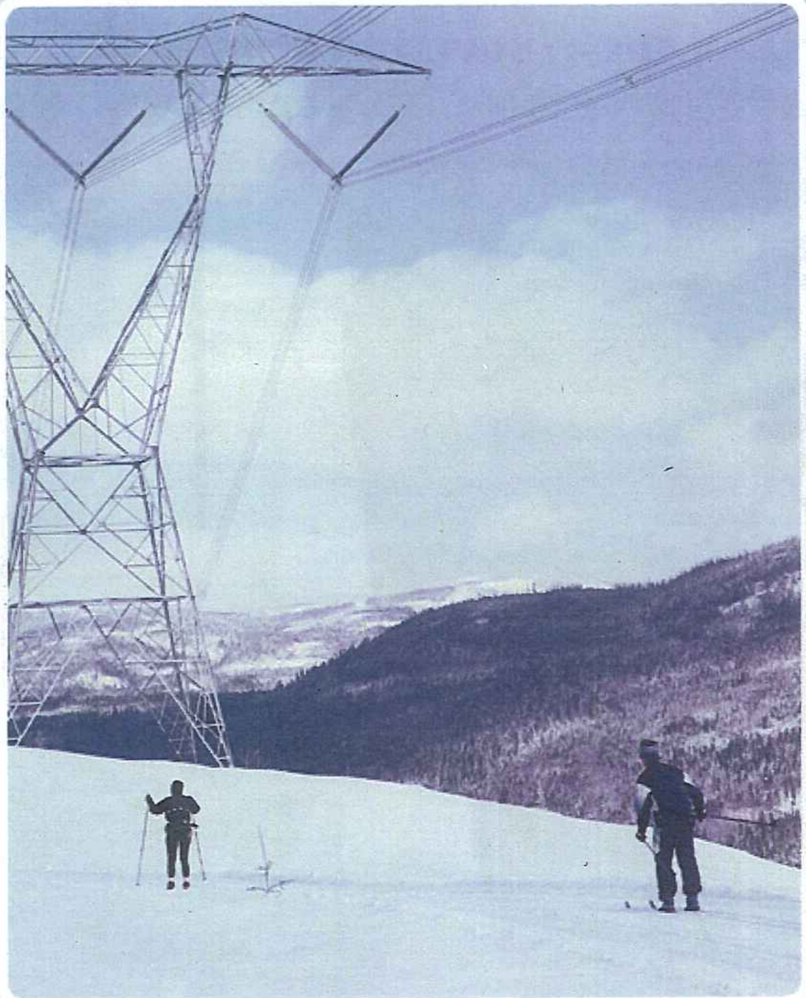
New York (HQT OASIS)

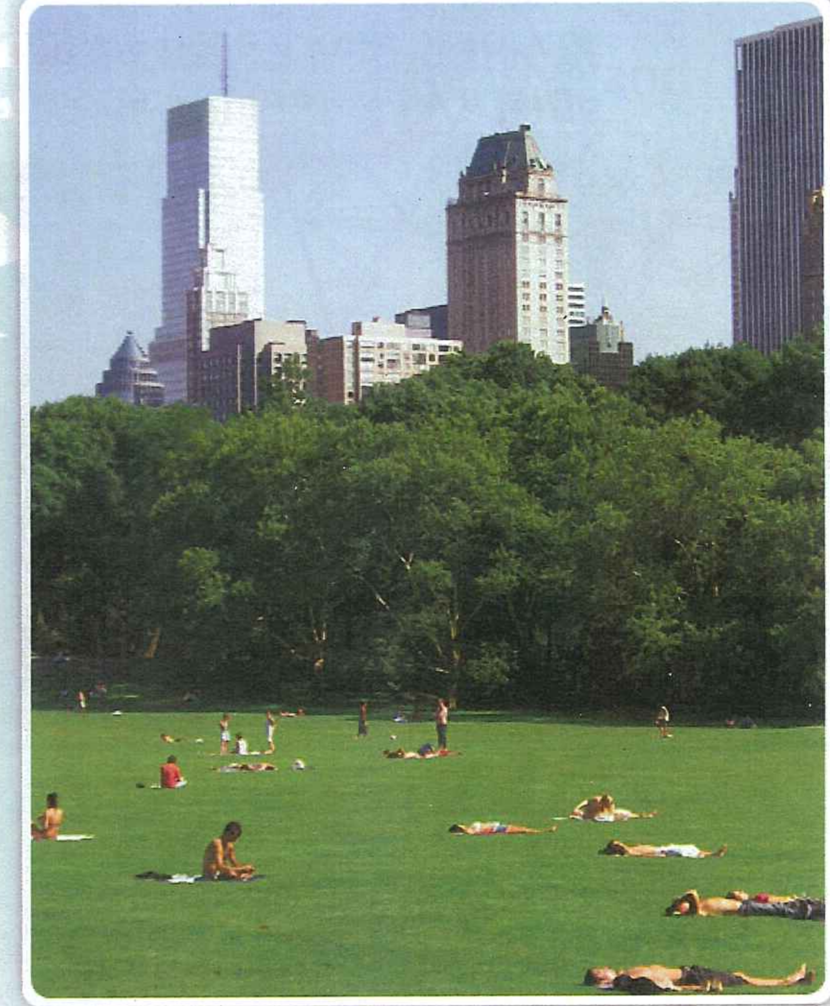
- **Massena interconnection:** Up to 1,800 MW dispatchable by NY/HQ/Ont.
- **Smaller interconnections:** Approx. 300-400 MW

37200 MW winter peak + 800 over last

Hydro Québec Production

Natural fit between Hydro-Québec Generation's supply and New York / US Northeast peaking needs





- Winter peak: 37,220 MW
- Summer peak: approx. 21,500 MW

Hydro Québec Production

Clean and Renewable Energy

Renewable energy is available from our side, supported by a large generation and transmission access, and we have a long history of energy exchanges with our neighbours. We also offer a flexible, adaptive commercial approach and a proven reliability of supply.

Hydro Québec Production

Summary Points

- We have an extensive and expanding portfolio of hydro ressources
- Our stated provincial and corporate strategy is to increase exports
- We are directly connected to four major northeast markets
- We are open to long-term contracts
- We are working to meet the technical and regulatory challenges we face in increasing exports through long-term contracts

Hydro Québec Production

HQ EnergyServices US
A subsidiary of Hydro-Québec

How HQUS Could Help North-East United States Meet its Short- and Long-Term Energy Needs

Christian G. Brosseau
President, HQUS

Nova Scotia Power Inc. - April 6th, 2009

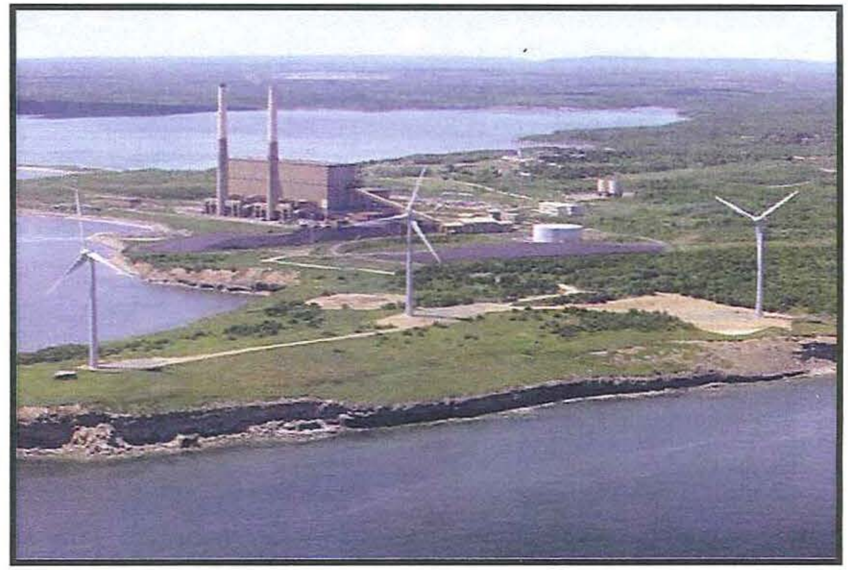
B

Nova Scotia Power
and
Bangor Hydro Electric

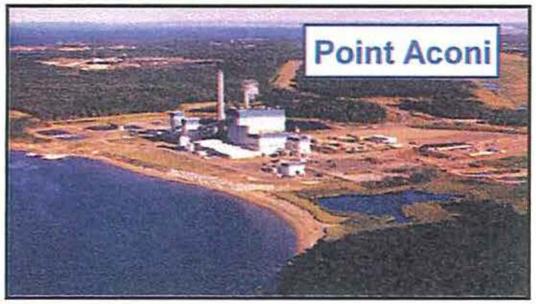
Montreal, Quebec
April 6th, 2009

Nova Scotia Power

- Provides generation, transmission and distribution to Nova Scotia
  - Approximately 70% of Emera's net income
- Regulated electricity rates and Fuel Adjustment Mechanism
- 2293 MW of capacity in Nova Scotia
- 75% of energy from coal and pet coke
- Energy projects
  - Tufts Cove 6 waste heat recovery
    - 150 MW CCGT
  - Trenton 5 baghouse and generator
  - Mercury reduction project
- Renewable energy development
  - 246 MW of wind under development through PPA's
- 2009 capital spending of approximately $230 million



Nova Scotia Power –Thermal Fleet

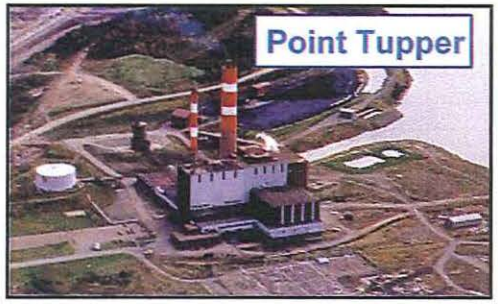


186 MW – 1 unit

Fuel: petcoke and coal-fired CFB technology

Operational in 1993

Largest CFB in Canada



150 MW – 1 unit

Fuel: petcoke and coal

Operational in 1973

Size: 600 MW – 4 units

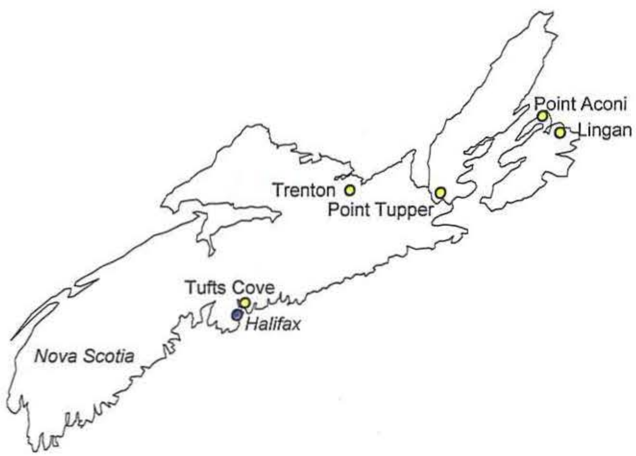
Fuel: petcoke and coal

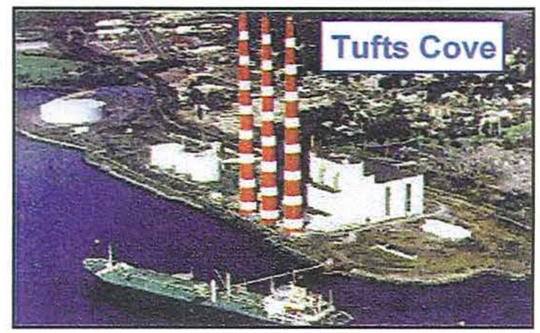
Operational in 1979, 1980, 1983, 1984

310 MW – 2 units

Fuel: petcoke and coal

Operational in 1969, 1991





430 MW – 5 units

Fuel: oil and gas

Operational in 1965, 2002, 2004

2 gas-fired combustion turbines

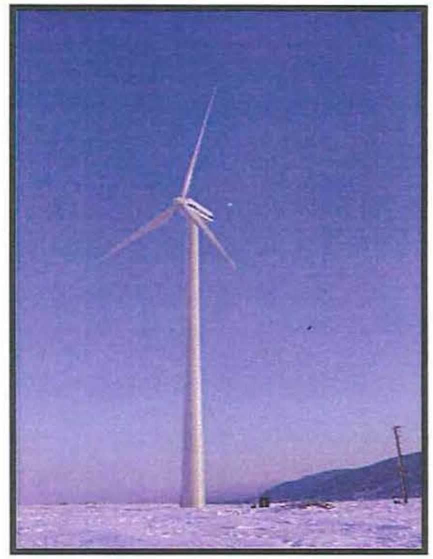
Oil/gas flexibility

Bangor Hydro

- Bangor Hydro's core business is the transmission and distribution of electricity to customers in Maine.
- Approximately 15% of Emera's consolidated net income
- Allowed Return on Equity:
  - Distribution 10.2%
  - Transmission 10.9% - 12.4%
  - Stranded Costs 8.5%
- BHE has approximately $100 million of transmission development currently underway in the state of Maine
- Growth coming from additional invested capital focusing on transmission development to serve its customers and the wider needs of New England
- Opportunities for additional wind and biomass generation to increase renewables in Maine
- 2009 capital spending of approximately $60 million

Becoming Cleaner and Greener

- NSPI has contracted for 246 MW of wind which will increase the wind on the ground in Nova Scotia by five fold
- BHE focus on transmission of renewable energy from Maritimes and northern Maine to high-demand regions of New England
- NSPI investing in a waste heat recovery project at Tufts Cove Power Plant
- NSPI investing to improve operational and environmental performance at Trenton Unit 5
- Emera investment in Open Hydro
- Nova Scotia Power will launch first tidal unit in Bay of Fundy in 2009



Potential Energy Supply

- Considerations
  - Volume
  - Energy availability, peak versus off-peak, seasonality
  - Capacity factor
  - Transmission reservations
  - Firmness
  - Pricing structure
  - Term of potential supply agreement(s)
  - Potential initiation dates
  - Other

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NON-CONFIDENTIAL

Request IR-156:

With respect to the NSPML/NSPI response to UARB IR-58, the response indicates the information requested is outlined in the application.

(a) For ease of reference and to ensure the parties understanding is complete, please provide by investment, in dollars, a summary of all costs outlined in the application, as well as all costs that may result from investments required to comply with the agreements and Nalcor's expectations.

(b) There are instances where rounding to the application request has been applied, such as UARB IR-30. Please include the actual estimate of the investment without rounding as well as the requested approval request.

Response IR-156:

(a) The costs that NSPML is seeking approval from the UARB are as summarized in section 1.10 of the Application. For further clarity, the following list provides more specific information about the costs outlined in the Application:

- The capital costs ($1.52 billion), and variance ($60 million), as outlined in Section 4.3. These costs will be recovered through depreciation over the 35 year life of the Project.
- The capital structure as outlined in Section 4.5.
- Rate of return on equity using the methodology as outlined in Section 4.6.
- Interest costs as outlined in Section 4.7 and 4.8. The current forecasted rate used in the Financial Model is 4 percent. The actual amount of interest will be better known upon the closing of external financing arrangements.
- The setting of AFUDC given the capital structure in Section 4.5 and as outlined in Section 4.8. The current estimate is $230 million.

NON-CONFIDENTIAL

- O&M costs and the true-up mechanism as outlined in Section 4.10. O&M costs will continue to be refined between now and the completion of construction.
- Incurred cash taxes as outlined in the Financial Model.
- Necessary NS Power capital upgrades as estimated at $31.5 million in Section 8.2.1 (these costs are anticipated to be offset by transmission revenues from Nalcor over the life of the Project).
- NS Power redispatch costs as outlined in Section 8.2.1 (these costs are anticipated to be offset by transmission revenues from Nalcor over the life of the Project).
- Backstop energy purchases by NS Power as outlined in Section 8.2.4.

(b) As noted in the Application (Figure 4-1), NSPML has estimated the capital cost of the Maritime Link facilities to be $1.4 billion as at Decision Gate 2. This number without rounding is as follows:

Maritime Link Facilities P50 Cost Estimate

	Rounded $ M	$
Transmission assets	350	356,434,968
Converter stations and related infrastructure	450	446,717,115
Marine	300	306,736,400
Project management	100	83,505,000
Other costs	200	195,096,547
Total, as spent	1,400	1,388,490,030

As spent, including estimated escalation / inflation / contingency

The total capital cost that NSPML has requested be included in rate base is $1.4 billion, plus a projected 20 for 20 true up of $120 million (total of $1.52 billion), plus a variance of $60 million.

NON-CONFIDENTIAL

The capital cost estimate noted above will be updated as at DG3 and will provided to the UARB prior to December 31, 2013 according to section 7(1) of the Maritime Link Regulations.

NON-CONFIDENTIAL

Request IR-157:

Regarding NSPML/NSPI response to UARB IR-70(b) and (c):

Please provide the references to the contractual provisions in the Nalcor Transactions or other agreements which support this response.

Response IR-157:

Under ECA Article 2.1 Nalcor agrees to deliver the NS Block to Emera in accordance with the terms of the Agreement. If it fails to do so, this is a default under ECA Section 8.1(b). There are no provisions which give Nalcor an absolute excuse from delivering the NS Block, other than Extended Force Majeure. A contractual or other dispute with Hydro Quebec would not constitute Force Majeure.

Pursuant to ECA section 8.4, if Nalcor fails to deliver the NS Block as a result of a Forgivable Event, the energy must be delivered at a subsequent time, and in accordance with ECA Schedule 5. Forgivable Events include Force Majeure, but specifically exclude low water flow arising from lack of precipitation (ECA Force Majeure definition).

If the failure to deliver the NS Block is not a Forgivable Event, then ECA section 8.4 applies.

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Request IR-158:

With respect to the NSPML/NSPI response to UARB IR-72, "Anticipated and known costs" are included from Figure 8-1.

(a) Please provide a breakdown of which costs are "known" and which are "anticipated".

Response IR-158:

Costs associated with the transmission upgrades are "known" to the degree of the study work completed. The estimates will be validated upon completion of final design and are currently estimated at $31.5M. The costs listed are, therefore, anticipated costs based on the Company's best estimates.

NON-CONFIDENTIAL

Request IR-159:

With respect to NSPML/NSPI response to UARB IR-74, b):

The Utility has responded that they have not performed this analysis as part of the application.

(a) Please explain why the Utility believes that this application is the best option if they have not run such an analysis.

(b) If the transmission upgrades are a benefit to this project over other options, please prepare an analysis that compares the current system ability at various monthly loads with the projected system ability after transmission upgrades.

Response IR-159:

(a) In NSUARB IR-74, the company has identified expected transmission investment in Nova Scotia of up to $31.5 M. The $31.5 M estimate resulted from studying the ability to create a path through Nova Scotia through the use of both Transmission Upgrades and redispatch of the generation fleet. This work was performed as part of the transmission study work in TSR400. Although there was no independent analysis performed to demonstrate the balance between capital investment and redispatch, the knowledge gained from previous interface upgrade costs and performance was used to minimize costs in this work.

(b) The increased capability on the Transmission path is expected to be approximately 80-100 MW year round. Before the upgrades, the summer rating is 700 MW and the winter rating is 900 MW. The final result will be understood when the detailed facility studies are completed.

NON-CONFIDENTIAL

Request IR-160:

With respect to the response to UARB IR-76 please confirm that:

(a) **Nalcor is obligated to begin delivery of the NS Block when Muskrat Falls and LIL are completed, and**

(b) **that, in the event of delays to Muskrat Falls or LIL, there is no obligation is to begin deliveries before they are both completed**.

Response IR-160:

(a) Nalcor is obliged to commence delivery of the NS Block upon (i) the completion of the start-up and testing activities required to demonstrate that three generating units at the Muskrat Falls Plant are ready to reliably operate in accordance with their design criteria; and (ii) the commissioning of the Labrador Island Link and the Labrador Transmission Assets.

(b) Correct, as it pertains to the NS Block. If, however, Muskrat Falls is in operation and the LIL is completed, but the third generating unit is not yet in service, Nalcor is required to offer the excess energy to Emera if it otherwise intends to export such energy from Muskrat Falls.

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Request IR-161:

With respect to the NSPML/NSPI response to UARB IR-77, Attachment 2:

It appears p. 10 of 11 is missing information, please re-file or explain otherwise.

Response IR-161:

The original document contains only the title of the page. There is no other information on the page.

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Request IR-162:

With respect to NSPML/NSPI response to UARB-84:

The Utility indicates the "The Muskrat Falls electricity has value in the New England market when that market requires electricity; whether a particular jurisdiction identifies that electricity as meeting domestic renewable energy standards could, presumably, change the value of that electricity."

(a) Why is Nova Scotia not permitted to sell this electricity with the renewable credit?

(b) Has the Utility made any effort to quantify the reduction in the value of that electricity?

Response IR-162:

(a-b) NSPML's response to NSUARB IR-84 explained that NSPML has not done the research to determine how each New England state would treat the renewable energy status of Nalcor energy, and that the Maritime Link Project is not based upon the economics of exporting any portion of the Nova Scotia Block.

Paragraph 2.3(a) of the Energy and Capacity Agreement (Appendix 2.03) states:

> …the Nova Scotia Block is intended to enable Emera to satisfy obligations arising pursuant to the RES and/or legislation regarding greenhouse gas emissions. For the purposes of RES and greenhouse gas compliance, Emera will own the GHG Credits related to the Nova Scotia Block. Emera shall not sell these GHG credits…

NS Power will use the Nova Scotia Block to comply with federal greenhouse gas emissions reduction requirements and the RES Regulations. The commitment not to sell the GHG credits is consistent with the need to use the electricity to meet domestic legislative and regulatory requirements. This commitment does not reduce the value of the electricity to Nova Scotia customers. The value of the NS Block is that the electricity enables NS Power to comply with the requirements under Federal and Provincial legislation and regulations.

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Request IR-163:

With respect to the response to UARB IR-88:

(a) The response provided responded to only part a) of the question. Parts b, c, and d were requested to improve the comparability of the options. Please provide the requested responses in parts b, c and d.

(b) Additionally, please provide an updated Figure 6-5 "Other Import Key Assumptions" as provided originally on p. 126 of your application.

(c) Additionally, with the revised information please provide an updated Figure 6-6 "Comparison of Alternatives – Base Load" as provided originally on p. 128 of your application.

Response IR-163:

(a) The original question (b) was "**Please provide a copy of the import entity's publicly available financial statements that demonstrates the entities' actual rate of return and actual capital structure".** The capital investment to be made for the Other Import Option is assumed, for modeling purposes, to be made by an Emera company, and the amounts reflected are an estimate of the ROE (10 percent), debt rate (5 percent) and capital structure (60 percent debt, 40 percent equity) that would be recovered from Nova Scotia ratepayers on the direct investment in the transmission infrastructure. The prices for the energy associated with the Other Import option are market based. For this reason, parts b-d were answered as part of the singular response to IR-88 and the response could have provided more clarity in that regard.

(b-c) As stated above, there are no financial statements to update therefore Figures 6.5 and 6.6 remain unchanged.

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Request IR-164:

With respect to NSPML/NSPI response to UARB IR-89:

(a) It appears the Utility has indicated they have no concerns with respect to the AAA credit rating being achieved. Please confirm.

(b) With respect to the response in part B that indicates NSPML expects spending beyond that currently budgeted (and in excess of the federal loan guarantee restrictions) would be more expensive then the federally guaranteed debt. Please quantify the cost of additional debt, and expected interest rate required if it was rated similar to:

- **(i) Emera**
- **(ii) NSPI**
- **(iii) Nalcor.**

Response IR-164:

(a) Confirmed. In the Federal Loan Guarantee Term Sheet, the Government formally committed to structuring a Federal Loan Guarantee that would achieve full credit substitution. Full credit substitution would allow the project to be treated as though it had the same credit rating as the Federal Government. The Federal Government is rated AAA.

(b) We are unable to quantify what the interest rate would be in this scenario. In the unlikely case this scenario unfolded, the interest rate would be impacted by, but not limited to, the terms and conditions of the FLG, ultimate financing structure and the market conditions and interest rate environment at the time. As indicated in UARB IR-89, none of the entities listed in part (b) of UARB IR-164 are rated as high as the Federal Government, and therefore we know that the debt would be more expensive.

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Request IR-165:

With respect to the NSPML/NSPI response to UARB IR-94:

(a) Please clarify if the utility has considered whether Canada Revenue Agency may not agree with the ownership of the assets as you have outlined in your financial projections.

(b) Similarly, has the utility considered whether Canada Revenue Agency may not agree with the cost assigned to the assets as you have outlined in your financial projections.

(c) Given NSPML is paying for 20% of the Nalcor assets (that will exist in a non-taxable entity) and only 20% of the Link assets, please explain why Canada Revenue Agency would not restrict the deductible CCA to 20% of the Link cost.

Response IR-165:

(a-c) NSPML is confident in how the ownership of the Maritime Link Project's assets will be treated for income tax purposes since the legal ownership is clearly outlined in the commercial agreements – for example, Article 2.2 (a) of the Maritime Link Joint Development Agreement clearly states that the Maritime Link is to be owned by NSPML. The 20 For 20 Principle provides that NSPML will be responsible for 20 percent of the total cost of the Maritime Link and LCP Phase 1 capital cost estimates. This Principle is satisfied by NSPML having legal title and ownership of the Maritime Link facilities which are currently estimated to have a capital cost of $1.4 billion. To reflect the fact that $1.4 billion is not 20 percent of the total cost of the Maritime Link facilities and the LCP Phase 1 given present estimates, a 20 for 20 true up would be required. For clarity, NSPML will have legal ownership of the Maritime Link facilities only – it will not have any legal title or ownership of the assets of LCP Phase 1 (Muskrat Falls, Labrador

Transmission Assets and Labrador-Island Transmission Link). Consequently, NSPML's financial statements and tax return will reflect ownership in the Maritime Link facilities and any true-up payment to Nalcor. From an accounting perspective any such true-up will be treated as a regulatory asset. From an income tax perspective this true-up payment is expected to be treated as eligible capital property. Since NSPML does not have any legal title to the assets of the Muskrat Falls generation facility, the Labrador Transmission Assets or the Labrador-Island Transmission Link, it will not include any of those assets in its tax filings.

Before the assets become available for capital cost allowance deductions, NSPML will categorize the costs into the appropriate and most advantageous classes available. At present, for purposes of preparing the Financial Model, NSPML assumed that all depreciable assets will be subject to an 8 percent capital cost allowance rate – the rate that transmission assets are currently depreciated at for income tax purposes. It is acknowledged that some components of the capital costs will relate to depreciable assets such as buildings, computer equipment, and automobiles which will be subject to rates different than 8 percent – some of which at more preferential rates such as 20 percent and 30 percent. That said, for purposes of the Financial Model, since the majority of the assets will be treated as transmission assets (which are subject to an 8 percent rate), NSPML used that capital cost allowance rate for all assets other than land and the true-up payment as noted previously. NS customers will benefit from any preferential tax rate classifications determined.

Please also refer to the response to NSUARB IR-175

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Request IR-166:

With respect to NSPML/NSPI response to UARB IR-102, the Utility provided the 2018 projected fuel savings. Have the savings for future years also been projected? If so, please provide by year.

Response IR-166:

For the purpose of the projections that have been publicly disclosed, the annual projection of net fuel savings was escalated by 2.3 percent after 2018. NSPML has not requested approval of revenue requirement or rate changes that have been publicly discussed. Please refer to CanWEA IR-115.

REDACTED

Request IR-167:

With respect to the NSPML/NSPI response to UARB IR-104:

(a) Please provide this confidential information through the Board's confidential website or explain why this material should be regarded any differently than other confidential information related to this hearing.

(b) Please also provide any fair market value assessments by property under consideration.

Response IR-167:

(a-b) NSPML's work in identifying necessary parcels of land and related property rights along the route of the Maritime Link is in process. There are more than three hundred parcels of land currently being identified along the route in both Nova Scotia and Newfoundland. In addition, in Newfoundland, a large component of the route is through Crown land. NSPML is not in a position at this time to provide fair market value assessments for parcels of land. More detail on the total estimated cost is as outlined below.

Land Purchases *	[redacted]
Land Agents	
Surveying	
Other (includes legal, CB route increases, roadside easements for grounding) **	
Total	**$12 million**

* More specific details on the land purchases are on the following page.
** Included in "Other" is an estimate of securing land rights in Cape Breton [redacted]

REDACTED

Land purchases	
Granite Canal to Cape Ray route in NL	[redacted]
Convertor stations and transition compounds NS and NL	
Grounding sites NS and NL	
Landing sites NS and NL	
Other	
Total	

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Request IR-168:

With respect to NSPML/NSPI response to UARB IR-105 that indicates a projected $58 million O&M true-up payment from Nalcor.

(a) Please provide a breakdown for how the $58 million was produced and also the possible risks that could affect the one-time payment.

Response IR-168:

Please refer to Tab V titled "O&M Forecast in the Financial Model (Appendix 4.01)". In that tab, the $58 million true up is reflected in cell C21. This value is determined by taking the net present value of each of the annual deltas as shown on line 19 of that same worksheet. The annual deltas are the differences between the annual projected O&M of the Maritime Link (line 17) and 20 percent of the total projected O&M of the Maritime Link and the LCP Phase I projects (line 18). Please refer to the response to SBA IR-321 for additional detail on these costs.

The true-up happens once construction is complete. There is a risk that actual O&M costs for the LCP Phase I projects might be less than those estimated at the time of true-up and that actual O&M costs for the Maritime Link might be more than those estimated at the time of true-up. There is also a possibility that the opposite may occur – that the actual LCP Phase I O&M costs may exceed those estimated and that the actual Maritime Link O&M costs may be less than those estimated. The 20 For 20 Principle mitigates these risks. Once the true-up payment is made, NSPML is responsible for only the actual O&M costs of the Maritime Link.

Please also refer to response to SBA IR-321.

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Request IR-169:

With respect to NSPML/NSPI response to UARB IR-115, part (d); the response indicates that:

> **The sale and purchase of additional Energy and GHG credits and any other renewable energy characteristics will be subject to future negotiations with Nalcor. The answer depends both on the outcome of those negotiations and the legislative requirements of Nova Scotia at the time of the negotiations.**

(a) Does this mean that if approval of the Maritime Link application is obtained further negotiations would take place to acquire the GHG credits for the supplemental block?

(b) If so, is that expected to increase the price for the supplemental block?

Response IR-169:

(a-b) No, there would not be a requirement for further negotiations nor additional payments in relation to obtaining the GHG Credits associated with the Supplemental Block. Of note is that the definition of the “NS Block” in the Energy and Capacity Agreement includes the Supplemental Energy, while Section 2.3 of that Agreement results in the transfer of the GHG Credits associated with the NS Block (including GHG credits associated with the Supplemental Energy). The referenced response (UARB IR-115 (d)) was intended to cover energy purchased in addition to the NS Block.

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Request IR-170:

If the alternative projects are considered equivalent from a lowest cost position, what other benefits or risks sway a decision that the Maritime Link is the better option over the alternatives?

Response IR-170:

There are many reasons that the Maritime Link Project is in the best interests of customers, in addition to the fact that the Maritime Link is the lowest long term cost alternative. These reasons include:

- NSPML has indicated that market based pricing has been used for the Maritime Link surplus energy; there is incremental value still available to be achieved in the netback benefit which will be subject to negotiations with Nalcor and would include avoided cost of Nova Scotia, New Brunswick and New England transmission service and fees to be recognized between the two parties.

- The Maritime Link provides the added benefit of improving the import potential from New Brunswick if Newfoundland is exporting, essentially avoiding potentially hundreds of millions of dollars to otherwise resolve the issues between Nova Scotia and New Brunswick.

- The system reliability, outside of the pure economic benefits have upside potential which has not been modeled, and that value will emerge during operation.

- The potential to trade or buy and sell ancillary services with Newfoundland and thereby reduce overall costs for Nova Scotia,

- The potential to benefit from future energy developments in Newfoundland and or develop tidal energy, or other intermittent sources in Nova Scotia, using the balancing energy which may be available over the Maritime Link,

- The continued utilization of the Cape Breton to Onslow transmission assets into the future as coal is displaced, reducing the risk of stranded assets,

- Please also refer to the NSPML's UARB Application, page 107, figure 6-1.

- Please also refer to lines 12-23 on page 105 and lines 1-4 on page 106 lines 1 to 4 of NSPML's UARB Application which read as follows:

> No available alternative method of complying with the regulations provides a lower long-12 term cost than the Maritime Link Project.
>
> It is important to note that even if the other options considered could have offered a comparably priced alternative, none bring the unique combination of benefits of the Maritime Link Project, which:
>
> - increases rate predictability for electricity customers through long-term (35 year) fixed cost contract
> - provides greater long-term electricity security
> - offers a strategic transformational opportunity for enhanced access to competitive
> - offers access to large, new, renewable electricity supplies for a minimum of 50 years
> - offers specific quantities of renewable energy at a stable cost for 35 years
> - provides enhanced reliability
> - strengthens Nova Scotia's connection to the North American grid to prepare for and to take advantage of many future energy scenarios
> - supports the development of additional intermittent renewable energy resources in Nova Scotia, such as wind and tidal
> - and many additional interconnection based benefits from options to procure more capacity from renewable sources to a strong, partner based, relationship with the largest undeveloped energy warehouse in our region and the future owner of Upper Churchill Falls output in 2041

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Request IR-171:

With respect to the accounting for this project, please explain:

(a) Why this project will not be accounted for as a Joint Venture?

(b) Are there any variances that would arise if the utility was not approved to apply US GAAP principles?

Response IR-171:

(a) As the assets of the Maritime Link will be 100 percent owned by NSPML during the 35 years that it will legally own these assets, joint venture accounting does not apply. Please refer to NSUARB IR-165 for further explanation of asset ownership.

(b) In the absence of the ability to apply USGAAP, NSPML would have two options: a) apply IFRS under which regulatory accounting is not currently permitted, or b) take the route that a number of Canadian regulated utilities have taken and apply to the Accounting Standards Board of Canada for an extension of Canadian GAAP which does permit regulatory accounting. Currently, this deferral is only permitted until the end of 2014. NS Power and NSPML has chosen to follow USGAAP.

If regulatory accounting did not apply, two of the more significant differences would be:

(i) the recognition of Allowance for Funds Used During Construction (AFUDC) would not be permitted, and,

(ii) the income tax expense would not be recognized on a cash basis but instead on a-future tax basis.

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Request IR-172:

It appears, based on Nalcor's final submission to the Newfoundland PUB, that Nalcor will be selling energy to Newfoundland and Labrador Hydro through a power purchase agreement.

(a) Was such an option presented to Emera or its subsidiaries? If so, provide detail.

(b) If such an option was presented please explain why it was not pursued.

(c) Please quantify the savings (or additional cost) that result under the proposed cost of service model as opposed to a power purchase agreement, using PPA quotes provided by Nalcor.

(d) If such quotes do not exist, in order to evidence the project as presented in the application is in fact the lowest cost option, please prepare an analysis assuming such a PPA came in at the rate NL Hydro negotiated with Nalcor that started at $76/MWh with a 2% escalation rate annually.

Response IR-172:

(a-b) While the possibility of a power purchase agreement was discussed by Emera and Nalcor for several months when the original Term Sheet was being negotiated no such proposal with cost details and specific terms and conditions was made by Nalcor to Emera or its subsidiaries. The parties could not come to an agreement on the appropriate pricing mechanism for a long-term deal. In the end, the method that was advanced and negotiated was based on the current 20 For 20 Principle. NSPML pays 20 percent of the cost of the total projects and in return receives 20 percent of the electricity from Muskrat Falls. Nalcor pays 80 percent of the cost and retains 80 percent of the electricity. The benefit of the current deal is that Nova Scotia ratepayers are acquiring electricity for a 35-

year term at the cost of capital. In a cost of capital arrangement such as this the price of the energy is known over the term of the 35 years. Often PPAs of this type would have the price tied to a market price or escalator, that price changing over the 35 years.

Section 8.6 of the Maritime Link - Joint Development Agreement outlines next steps with respect to a "PPA Option" in the event Emera decides not to sanction the Maritime Link and only Nalcor sanctions. However, as a result of the December 17, 2012 Sanction Agreement, this section is no longer applicable.

(c-d) As stated above, no PPA quotes were received from Nalcor for a 35-year power purchase agreement because the parties could not come to an agreement on the pricing mechanism for a 35-year term. The agreement between NL Hydro and Nalcor is between a parent and subsidiary company and does not reflect the terms that would apply between Nalcor and NSPML.

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Request IR-173:

Given the non-taxable status of Nalcor, please respond to the following:

(a) Would it be a lower cost option to have left the Link as a 100% Nalcor owned investment assuming they charged based on their cost of service model?

(b) If it assumed the scenario presented in a) is unlikely, please quantify, if all other costs remained the same as presented in your application, except the removal of the tax costs, what markup would have to be applied to Nalcor's cost of service model to reach a power purchase charge that is equal to what you have proposed as the lowest cost option.

Response IR-173:

(a) The commercial transactions were based upon NSPML funding the capital requirements to construct the Maritime Link, which was a means to lower the capital contribution required by Nalcor. The structure contained in the Application is the outcome of negotiations between the two companies and are to be taken as a whole. Pieces of the transactions cannot be segregated from the whole (that is, the tax exempt status of Nalcor). The question presumes that it was an option for Nalcor to build the Maritime Link and charge Nova Scotia customers on a cost of service model basis. This is not part of the agreement put forward in the Application.

(b) Hypothetically, if all other costs remained constant and there was a zero percent income tax rate, the net present value of the Maritime Link Project would be approximately \$100 million or 7 percent lower, still resulting in the Maritime Link Project being the lowest-cost long-term alternative. This could be a proxy for such a mark-up that would have to be added to a cost of service model but does not take into account other premiums that an Independent Power Producer may add for similar contract terms.

Request IR-174:

Please provide calculations to demonstrate how the $60 million potential overrun was determined assuming only 20% of the "at risk" amounts could be assigned to NSPML?

Response IR-174:

Figure 4-2 of the Application shows that if the estimated capital cost of the Maritime Link facilities increases from the current estimate of $1.4 billion to $1.7 billion (an increase of $300 million) that based upon the sharing of all Decision Gate 3 costs between NSPML (20 percent) and Nalcor (80 percent), that 20 percent of the increase of $300 million would be the responsibility of NSPML. Therefore, NSPML would be responsible for $60 million of that $300 million increase.

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Request IR-175:

Has NSPML/NSPI or any other Emera company performed due diligence on potential tax risks associated with the investment? If so, please identify the risks identified and responses that satisfied the concerns identified.

Response IR-175:

Emera's tax group reviewed the commercial agreements and the tax assumptions contained in the Financial Model. The company's external tax advisors were involved in the review of the key commercial agreements. NSPML is satisfied that the Project does not contain any material tax risks.

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Request IR-176:

On p. 74 of the application, it states:

> **The Regulations provide that NSPML may recover as Project Costs, once the Maritime Link Project is approved, 20 percent of the LCP Phase 1 and the Maritime Link facilities' costs. While Project Costs are influenced by the capital cost of the Maritime Link facilities, they are not limited to those costs.**

(a) Please explain how the Board will determine prudence with respect to costs not limited to the Maritime Link facility that NSPML will pay for?

Response IR-176:

(a) This is an application by NSPML to the UARB for approval of the Maritime Link Project and a plan to recover all Project Costs, including those related to building and operating the Maritime Link, pursuant to the *Maritime Link Act* and the *Maritime Link Cost Recovery Process Regulations* made under Section 6 of the Act. The Act vests the UARB with general supervision of NSPML and the Maritime Link Project, and the Regulations have been made, *inter alia*, to establish the criteria and conditions by which the Maritime Link Project is to be reviewed and considered for approval by the UARB. In turn, the Regulations direct the UARB to approve the Maritime Link Project if the Board is satisfied that the Project meets all the following criteria:

- the project represents the lowest long-term cost alternative for electricity for ratepayers in the province;

- the project is consistent with obligations under the *Electricity Act*, and any obligations governing the release of greenhouse gases and air pollutants under the *Environment Act*, the *Canadian Environmental Protection Act* (Canada) and any associated agreements.

The jurisdiction of the Board in this Application arises from the *Maritime Link Act* and, in particular, the *Regulations*. NSPML will seek UARB approval of the final true-up amount following the DG3 calculations, when the project status report is filed in Q4 2013. That request will allow the UARB to be informed about the final 20 For 20 calculations, and to approve the amount of the true-up payment that is prudently incurred to comply with the 20 For 20 Principle.

In respect of the prudence of Nalcor's activities in the LCP Phase 1 projects, please refer to NSUARB IR-195.

Request IR-177:

With respect to the Application, page 145, line 4, the Nova Scotia Transmission Utilization Agreement (NSTUA) is described as providing Nalcor with transmission services at prices which are a "proxy for the NS OATT".

(a) Please describe how NSPI currently uses and pays for transmission services within Nova Scotia, including how these arrangements relate to the provisions of the OATT (i.e. what type of transmission service is used, under what types of transmission rights and what durations are rights reserved).

(b) Will the provisions of the NSTUA require any change to the current arrangements enquired about in (i) above?

(c) Will the transmission services paid for by Nalcor under the NSTUA "on an as used basis" be provided from rights owned by NSPI (or an affiliate) and if so please describe the associated service, type and duration and whether these rights are currently owned or yet to be purchased.

(d) Please describe how the transmission services paid for by Nalcor under the NSTUA "on an as used basis" relate to the OATT and how they affect transmission-related costs recovered from NSPI customers.

Response IR-177:

(a) NS Power uses Network Integration Transmission Service as described in Part III of Open Access Transmission Tariff (OATT) for supplying its Native Load Customers (http://oasis.nspower.ca/site-nsp/media/Oasis/ApprovedOATT052005.pdf). Section 28.3 of the OATT describes this as firm transmission service over the Transmission System to the Network Customers.

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(b) NS Power interprets the IR to be intended to refer to “(a) above”. NS Power will contract with the NSPSO for a 330 MW Long-Term Firm Point-to-Point Transmission Service under the NS OATT. NS Power will utilize this transmission service, to schedule and transmit energy on behalf of Nalcor from Woodbine to the NS-NB border.

(c) The transmission services provided to Nalcor under the NSTUA will be effectuated through the 330 MW Long-Term Firm Point-to-Point Transmission Service under the NS OATT.

(d) Please refer to Section 2.3(b)(vii) and the definitions of “Daily Proxy Rate”, “Weekly Proxy Rate”, “Monthly Proxy Rate” and “Yearly Proxy Rate” in the NSTUA for a description of the calculation of the Applicable Tariff Charges and the associated correlation to the NS OATT. During the terms of the Agreement, NS Power does not anticipate that the provision of services to Nalcor under the NSTUA will affect transmission-related costs charged by NS Power to existing customers.

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Request IR-178:

With respect to Emera's current participation in Newfoundland markets:

(a) Please explain whether Emera does sell hydro energy currently or in the past.

(b) If so, please provide details related to what markets Emera is selling energy from Upper Churchill or other NL hydro to and whether there are any PPA's in place with third party purchasers.

Response IR-178:

(a) Acting as Nalcor's agent for its Recall Energy, Emera Energy sells hydroelectricity that originates in the Newfoundland/Labrador Market. Emera has not historically participated in, nor currently participates within, the Newfoundland market.

(b) Upper Churchill Falls energy is currently sold into the New York (NYSIO, Ontario (IESO) and New England (ISONE) Power Markets. There are no Power Purchase Agreements in place.

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Request IR-179:

Application Appendix 5.01, p. 67

In its review of the alternative options for Newfoundland and Labrador, Manitoba Hydro International used the "Cumulative Present Worth" (CPW) approach to measure the present worth of alternative options.

(a) Did NSPML use a different method to assess the alternative options in this Application?

(b) If so, describe the method used by NSPML and how it differs.

Response IR-179:

(a-b) NSPML used a similar approach in this Application. Manitoba Hydro International determined the net present value of a stream of annual costs extending to 2067 - the "cumulative present worth" (CPW). The alternative with the lowest CPW was considered the preferred option.

NSPML compared the alternatives in the Application based on the net present value of study period costs. The costs in the Application include the net present value of a stream of annual costs from 2015 to 2040 discounted to 2015, referred to as the planning period costs. The study period costs reflect the planning period costs plus the end effects for costs beyond 2040.

For capital investments, the end effects costs include the remaining lifetime of the initial investments made in the planning period plus replacement-in-kind for each asset beyond 2040. For operating costs, end effects are based on the load in 2040 and assumed to continue each year beyond 2040. The net present value of this stream of costs converges

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to a finite sum which is the capital and operating cost end effects. The Strategist model calculates this finite sum which is added to the planning period net present value cost to give the study period costs. The alternative with the lowest study period costs is the lowest cost alternative.

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Request IR-180:

Given the Disclaimer for the Maritime Link Financial projection that states:

> **This model has been prepared by NSP Maritime Link for illustrative purposes only; it is not necessarily reflective of final regulatory structure. No representation, warranty or undertaking (express or implied) is made with respect to the adequacy, completeness or accuracy of the model or the assumptions on which it is based.**

(a) What assurances, if any, can be given that those projections are reasonable?

(b) At what variance could a 90% confidence level be offered?

Response IR-180:

(a) The model has been reviewed within NSPML and Emera and we are confident it reflects an accurate and reasonable projection of the costs of the Project. The disclaimer does not call into question the accuracy of the model. Disclaimers are used in the event the model is used in a manner other than that for which it was originally intended or, given the complexity of the model, an unintended error is found by an external party.

(b) A 90 percent confidence level for the capital cost estimate is included on page 75 of the Application – the Maritime Link facilities estimated capital cost at a P90 is $1.5 billion. Figure 4.2 provides the 20 For 20 Principle calculations at the P50, P90, and P97 confidence levels. If the basis of the Application requested a P90 confidence level, this would result in a $40 million variance.

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Request IR-181:

The projections for each option have an element of escalation included. Please provide a table that indicates what level of escalation or other increase in price, in terms of percentage, by year for the following:

(a) Natural Gas fuel price expectations.

(b) Other Import option modeled

(c) Indigenous wind option modeled

(d) Maritime Link option modeled

Please explain the reasoning behind any significant variations in the percentage increase between the options a-d above.

Response IR-181:

(a) Please refer to Attachment 1. It shows the assumed gas prices for fuel delivered to Tufts Cove and resulting annual escalations.

(b) Please refer to Attachment 1. It shows the total annual revenue requirement for Operating and Capital costs for the Other Import option (Appendix 6.06, page 2 of the Application) and resulting annual escalations. These values are outputs from the Strategist model. Strategist takes the input data, executes the run and produces the output results.

(c) Please refer to Attachment 1. It shows the total annual revenue requirement for operating and capital costs for the Indigenous Wind option (Appendix 6.06, page 3 of

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the Application) and resulting annual escalations. These values are outputs from the Strategist model. Strategist takes the input data, executes the run and produces the output results.

(d) Please refer to Attachment 1. It shows the total annual revenue requirement for operating and capital costs for the Maritime Link option (Appendix 6.06, page 2 of the Application) and resulting annual escalations. These values are outputs from the Strategist model. Strategist takes the input data, executes the run and produces the output results.

The average escalation between (a)-(d) above varies by less than 1 percent between each option.

	Natural Gas Delivered to TUC		Maritime Link		Other Import	
	CAD$/MMBtu		*CAD$k*		*CAD$k*	
2018	$8.62		723,662		717,277	
2019	$9.04	4.8%	740,941	2.4%	734,201	2.4%
2020	$9.46	4.6%	753,998	1.8%	764,534	4.1%
2021	$9.92	4.9%	772,487	2.5%	782,625	2.4%
2022	$10.35	4.3%	783,425	1.4%	805,101	2.9%
2023	$10.79	4.3%	783,341	0.0%	800,104	-0.6%
2024	$11.24	4.2%	794,579	1.4%	815,037	1.9%
2025	$11.72	4.2%	810,816	2.0%	835,274	2.5%
2026	$11.99	2.3%	832,027	2.6%	849,994	1.8%
2027	$12.26	2.3%	837,366	0.6%	865,966	1.9%
2028	$12.53	2.2%	862,696	3.0%	881,804	1.8%
2029	$12.81	2.2%	879,715	2.0%	906,415	2.8%
2030	$13.08	2.1%	949,476	7.9%	939,322	3.6%
2031	$13.36	2.1%	970,346	2.2%	953,719	1.5%
2032	$13.65	2.1%	978,246	0.8%	972,987	2.0%
2033	$13.94	2.2%	1,003,888	2.6%	1,053,735	8.3%
2034	$14.24	2.2%	1,032,600	2.9%	1,090,322	3.5%
2035	$14.55	2.2%	1,114,895	8.0%	1,126,811	3.3%
2036	$14.87	2.2%	1,150,228	3.2%	1,154,369	2.4%
2037	$15.19	2.2%	1,169,443	1.7%	1,181,084	2.3%
2038	$15.50	2.0%	1,201,747	2.8%	1,208,284	2.3%
2039	$15.81	2.0%	1,236,470	2.9%	1,244,717	3.0%
2040	$16.12	2.0%	1,275,801	3.2%	1,296,296	4.1%
Average		2.9%		2.6%		2.7%

Wind	
CAD$k	
667,782	
752,980	12.76%
707,476	-6.04%
788,199	11.41%
837,417	6.24%
848,615	1.34%
874,593	3.06%
912,694	4.36%
947,263	3.79%
967,696	2.16%
990,710	2.38%
1,018,407	2.80%
1,095,446	7.56%
1,120,756	2.31%
1,151,376	2.73%
1,201,095	4.32%
1,231,827	2.56%
1,253,327	1.75%
1,295,131	3.34%
1,325,727	2.36%
1,362,969	2.81%
1,438,911	5.57%
1,429,170	-0.68%
	3.6%

NON-CONFIDENTIAL

Request IR-182:

With respect to NSPML/NSPI response to Booth IR-3, iii and MPA IR-19):

Is there an estimate of the cost assigned to compliance with the government of Canada's or other hedging requirements? If so, please provide.

Response IR-182:

The interest rate assumption of 4 percent includes all borrowing costs including those related to the Federal Loan Guarantee. Details of the hedging agreement will be finalized with the Federal Government consistent with the Federal Loan Agreement prior to financial close.

NON-CONFIDENTIAL

Request IR-183:

With respect to NSPML/NSPI response to Booth IR-6, c):

Please provide the list of utility assets Ms. McShane was asked to rank and the assigned ranking.

Response IR-183:

In the ongoing BCUC generic cost of capital proceeding, the BCUC, in its minimum filing requirements, requested a business risk ranking and rationale by utility industry sector, specifying electricity, natural gas and alternative energy service providers. Ms. McShane's testimony in that proceeding stated that "It is virtually impossible to rank the three sectors generically, largely because the utilities that constitute the "electricity sector" in Canada (as well as in the United States) span a wide range of business risk." Ms. McShane stated that "Given the different electricity industry models in use in Canada, rankings are provided for electric transmission, distribution and vertically integrated utilities, as well as for natural gas distribution and alternative energy service providers." As indicated in response Booth IR-6b, she also stated that the rankings she provided were "intended to be "generic" that is, based on fundamental characteristics that are generally common to utilities in each category. The generic utility sector business risk rankings from lowest to highest were electricity transmission, electricity distribution, natural gas distribution, vertically integrated electric utilities and alternative energy service providers.

NON-CONFIDENTIAL

Request IR-184:

With respect to the NSPML/NSPI response to MPA IR-20 that indicates no tax planning was undertaken between entities, please respond to the following:

(a) In theory NSPML will pay for 20% of the assets referred to as Lower Churchill Phase 1. Please confirm these assets will be owned by Nalcor, a non-taxable entity, from day one.

(b) Is it reasonable to assume those assets would attract no tax and therefore should not be included in any revenue requirement? Please explain if otherwise.

(c) In theory NSPML will pay for only 20% of the Link assets, that NSPML claims ownership of for 35 years, is there a risk Canada Revenue Agency would restrict or re-assess the claim for CCA to 20% of the $1.52b Link assets cost.

(d) How likely is it that these assets could, given the automatic transfer at $1, be considered entirely owned by Nalcor and therefore attract no tax?

(e) How likely is it that the CCA deductions projected with respect to these assets could be reassessed or denied by Canada Revenue Agency resulting in no CCA deduction to NSPML?

(f) What has the applicant done to ensure any negative consequences such as CRA denying a CCA deduction are not a risk to ratepayers?

(g) Does the 20 for 20 principle, as currently agreed, pose tax risks to NSPML, NSPI or NS Ratepayers?

NON-CONFIDENTIAL

(h) Please explain why, when it appears there may be opportunities to minimize taxes, such tax planning between entities was not pursued.

Response IR-184:

(a-g) Please refer to NSUARB IR-165.

(h) NSPML and Nalcor are arm's-length companies that do not share common ownership, have different mandates, different stakeholders, different customers and are regulated differently. As a result, tax planning between the companies was not pursued. Further, taxes that will be paid by NSPML will serve to benefit NS taxpayers and the Government of Canada who is providing support to the Project via the Federal Loan Guarantee.

NON-CONFIDENTIAL

Request IR-185:

With respect to the NSPML/NSPI response to Liberal IR-15:

(a) Please clarify how NS Power will remain first in line to purchase surplus energy.

(b) Please explain what is considered surplus energy at that time.

Response IR-185:

(a) The reference to first in line simply means that NS Power is the closest geographic market to Newfoundland. In other words, the energy could be purchased before it flows through Nova Scotia, to New Brunswick and on to New England which provides Nova Scotia customers a strategic economic advantage over all others further down the transmission line. Nalcor has to pay a transmission tariff in any jurisdiction through which it takes its energy. If it sells the energy to Nova Scotia it will avoid paying those delivery charges, making it economically advantageous for them to do so.

(b) Unless commercial negotiations result in a contractual arrangement between NS Power and Nalcor at that time (after 35 years) for some amount of energy, all of the energy which Nalcor delivers across the Maritime Link would be considered "surplus".

NON-CONFIDENTIAL

Request IR-186:

The Model uses a 31% rate, which is the combined tax rate in Nova Scotia.

(a) Has consideration been given to which provinces NSPML will have a permanent establishment in for tax purposes?

(b) If a permanent establishment exists in Newfoundland, for example, and a lower effective tax rate is achieved as opposed to that presented in the model will this be flowed through for the benefit of ratepayers?

Response IR-186:

(a) Yes, consideration has been given to which provinces NSPML will have a permanent establishment for tax purposes. NSPML will have permanent establishments in NS and NL. Please see Part (b) for further information on how this has been modeled.

(b) Yes. The cash taxes are a direct flow through to NS customers. All tax planning opportunities available will be pursued and will be to the benefit of customers. The Financial Model conservatively used the higher of the two combined provincial rates (Nova Scotia & Newfoundland).

NON-CONFIDENTIAL

Request IR-187:

In Appendix 4.01 O&M Forecast tab, no tax rate is applied to the $57.9M one time true up payment, as it is noted that amount is "not taxable in 2017". In Appendix 4.01 Tax Schedule tab, the $57.9M true up payment is included in taxable income in 2017. Absent the availability of tax losses in 2017, the $57.9M true-up would have been subject to a 31% tax rate. If no tax losses existed in 2017, would the true-up payment have increased due to the fact that the receipt is subject to 31% tax?

Response IR-187:

No. The true-up is calculated using forecasted O&M expenses, which are pre-tax amounts. For clarity, the receipt of a true-up payment from Nalcor to NSPML would be taxable income to NSPML. In the year that such payment is forecasted to be received (2017), NSPML is forecasted to have sufficient income tax losses on hand to offset this receipt. From a tax accounting perspective, since NSPML expects to use the cash tax method of accounting for taxes, there wouldn't be a tax expense resulting from this receipt. That said, tax losses on hand would be used.

NON-CONFIDENTIAL

Request IR-188:

(a) Has consideration been given to when the asset is "available for use" for tax purposes? Specifically, has the two year rolling start rule been considered? Furthermore, if the rolling start rule applies, consideration should be given to whether the half year rule applies.

(b) If accelerated CCA deductions are achieved please confirm this would further reduce the cost of the Link and be passed along to ratepayers.

Response IR-188:

(a) For purposes of modeling income taxes in the Financial Model, the depreciable assets were considered available for use in the year of first commercial operation. NSPML will optimize all available CCA deductions using available legislative means within the Income Tax Act which would include but not be limited to the rolling start rules.

(b) Confirmed.

NON-CONFIDENTIAL

Request IR-189:

Is the capital cost to NSPML for tax purposes based on 100% of the cost of the Maritime Link facilities at DG2 or 20% of the combined LCP Phase 1 and Maritime link costs? Could the cost for tax purposes be different than the cost for accounting or rates?

Response IR-189:

Please refer to NSUARB IR-165.

NON-CONFIDENTIAL

Request IR-190:

If 20% of the combined LCP Phase 1 and Maritime link costs are being used for tax purposes.

(a) Has consideration been given to whether NSPML has all the incidences of title (ie. possession, use and risk) on the Nalcor assets and whether these assets would also be considered Class 47?

(b) What protects NS Ratepayers from a negative tax assessment associated with incidences of title?

Response IR-190:

(a) Please refer to NSUARB IR-165.

(b) The commercial legal agreements, which specify the ownership of the Maritime Link and LCP Phase I assets, provide NS customers protection from such risks.

NON-CONFIDENTIAL

Request IR-191:

In NSPML/NSPI response to UARB IR-106:

(a) **Please confirm if NSPML is required to make a cash compensation payment to Nalcor in accordance with the 20 for 20 principle, this will be classified Eligible Capital Property.**

(b) **If the reverse occurs and Nalcor makes a cash compensation payment to NSPML, what is the nature of the payment? Is it a taxable receipt or could it be offset against the tax cost of the depreciable asset, thereby reducing future CCA claims.**

Response IR-191:

(a) NSPML expects that, in the event a capital true-up payment is made to Nalcor under the 20 For 20 Principle, the payment will be treated as Eligible Capital Property for income tax purposes.

(b) NSPML expects that, in the event a capital true-up payment is made from Nalcor to NSPML under the 20 For 20 Principle, the payment would be considered a capital contribution for income tax purposes and thus reduce the tax cost base of the Maritime Link.

NON-CONFIDENTIAL

Request IR-192:

(a) Has consideration been given to whether the Canada Revenue Agency will challenge the sale price of $1 on the basis that the parties may be viewed, under tax principles, as not dealing at arm's length and the fair market value is significantly greater than the $1.

(b) Please explain what protects NS Ratepayers from a negative tax assessment?

Response IR-192:

(a) It is NSPML's view that this transaction between Nalcor and NSPML is at arm's length and as a consequence the $1 agreed upon sale price will be viewed as such. Please also see response to MPA IR-029.

(b) NS customers are protected due to the arm's-length relationship between NSPML and Nalcor. In addition, at the end of the 35th year of the commercial agreement, a balance of approximately $37 million remains unclaimed in the capital cost allowance pool (Appendix 4.01, tab "Tax Schedule"). This balance could be used to protect NS customers in the unlikely event of a negative tax assessment that deemed a FMV greater than $1. The $37 million would serve to shield taxable income that may arise in that event.

NON-CONFIDENTIAL

Request IR-193:

With respect to the NSPML/NSPI response to Liberal IR-19:

(a) Please quantify the impact adjusting the "Other Import Option" debt rate to reflect 4% interest rate as though supported by the federal loan guarantee.

(b) Please include this in the updated Figure 6-5 "Other Import Key Assumptions" as provided originally on p. 126 of your application, requested in UARB IR-163 above.

(c) Please include this in the updated Figure 6-6 "Comparison of Alternatives – Base Load" as provided originally on p. 128 of your application, requested in UARB IR-163.

Response IR-193:

(a) If the Other Import Option had a 4 percent debt rate, the NPV difference in the period from 2107 to 2040 would be approximately $37 M. The Figures 6.5 and 6.6 were not updated in NSUARB IR-163 as the original assumptions were not from a specified company.

(b) Figure 6-5 Other Import Key Assumptions with 4 percent Debt Rate

Value	**Assumption**
$676 M	Capital Cost (includes AFUDC)
$22 M	NBOATT Charges, escalates at 1% per year
60%	Percentage of rate base funded by debt
4%	Debt rate
10%	Rate of ROE
3.30%	Transmission losses through NB
1-Oct-17	Commercial Operation Date
45 years	Depreciation
165 MW	Firm Contract Purchase
932 GWh	Annual energy (before Supplemental Energy)
500 MW	Transmission Link

(c) The PV amount for the Study period is not available without re-running the Strategist model. While we cannot re-run Straegist in the available time, we have made a high level estimate of the number of $37 million for the Planning Period, as noted in part (a).

NON-CONFIDENTIAL

Request IR-194:

Given that it has been isolated from the rest of North America, does the electricity system on the island of Newfoundland comply with NERC and NPCC requirements?

Response IR-194:

The Newfoundland Island system has been operated according to provincial standards, consistent with other Canadian Electricity Association member utilities; there is no jurisdictional requirement for Newfoundland to be NERC compliant. The Maritime Link is being developed as an asynchronous HVDC interconnection which means the Newfoundland island system is not required to become NERC compliant. That being said, all aspects of the Maritime Link, including the interconnecting substation in Bottom Brook, are being designed to NERC standards.

NON-CONFIDENTIAL

Request IR-195:

Understanding that 80% of the costs under the proposed 20 for 20 principles are a result of costs driven by the DG3, managed by Nalcor, and have not received regulatory approval. Please explain how the Board can be assured that 80% of the costs are being prudently incurred.

Response IR-195:

Please refer to the Maritime Link Application, Section 5, specifically Section 5.2 which outlines NSPML's due diligence activities. A review of Nalcor's DG3 cost estimates for Other LCP Projects was completed by Manitoba Hydro International for the government of Newfoundland and Labrador. Manitoba Hydro found the estimates to be reasonable. The Government of Newfoundland and Labrador, and Nalcor then sanctioned the project on December 17, 2012.

Please refer to the Application, Appendix 5.01 and the news release from the NL Government found at http://www.releases.gov.nl.ca/releases/2012/weeks/dec17dec23.htm.

Please also refer to Enerco IR-13 and Enerco IR-14.