Board of Commissioners of Public Utilities
120 Torbay Road
P.O. Box 21040
St. John's, NL
A1A 5B2

February 5, 2014

Notes for Presentation - Pre-Hearing Conference

The root cause of what went wrong at Holyrood, in the early days of January, 2014 and at related power assets, is critically important. Undoubtedly, it will be the PUB's top priority. But, any investigation that attempts to assess that issue, in isolation, will not adequately serve the public interest.

Other issues threaten the security of our power supply after commissioning of Muskrat Falls in 2017. They are substantial issues. They require a deliberate, objective and transparent evaluation.

For that reason, I am here today to respectfully ask the PUB to ensure that its investigation is as wide as possible.

Many people suffered great personal inconvenience; individual citizens and businesses endured financial loss. Public confidence in our electrical system has been badly shaken. It needs to be fully restored.

I submit, Mr. Chairman, this issue of confidence is not solely bound up in the 'nuts and bolts' of Holyrood; it is inextricably tied to decisions already taken by Nalcor relating to commitments of Muskrat Falls power, recall power and current on-Island generation.

Any serious examination of our power system seems always to lead us back to the question of Holyrood. The issue is not just about how that facility's capital repair or replacement ought to be managed. From the stand point of security of supply, during the post-Muskrat commissioning period, questions abound whether Holyrood ought to be decommissioned as planned.

Therefore, the PUB's assessment period must extend well beyond the commissioning date of Muskrat Falls.

Does it make sense, for example, that a significant part of our power generation, after 2017, will rely upon the Labrador Island Link (LIL) located 1100 km. away from the populous and growing area of the Avalon Peninsula?

We have to truly wonder if the exaggerated promise of Muskrat Falls has caused a paralysis of thinking. Has it obviated the need to consider a back-up plan to that Project's inherent weaknesses? Have we forgotten how much power has been committed to Nova Scotia in order to effect Muskrat sanction?

As ironic as it may seem, Holyrood may well constitute that back-up plan.

Others have noted that, upon commissioning of Muskrat Falls and the planned decommissioning of Holyrood, in 2021-22, there will be a net increase of power to the Island Grid of a mere 120 MW, after taking into account line losses, delivery of the Nova Scotia Block and Nalcor's 70 MW commitment to Alderon. In isolation, that issue speaks to the question of the reliability of Nalcor's demand forecast and its ability to meet demand in excess of that forecast.

But, other issues come into play, too, raising huge questions of whether our reliance on Muskrat Falls, as the answer to our power security, is warranted.

I want to highlight three of those issues here:

1. **Water Management Agreement.** The impact of a possible failure by Nalcor to secure the water rights claimed under the Water Management Agreement constitutes a major concern. Muskrat Falls is estimated to generate 824 MW of power. Nalcor stated in its 2009 Application to the PUB that without a working Water Management Agreement, the capacity of MF would be limited. One deduction from the evidence Nalcor presented suggests that, in the absence of the WMA, the facility would be limited to approximately 170 MW of continuous delivery. Nalcor stated: it would have to "chase the flows" (page 16, Water Management Agreement Application-Pre Filed Evidence by Nalcor Energy).

   How is it possible that this critical question can be de-linked from any decision to decommission Holyrood?

   Hydro Quebec's challenge to the water rights issue in the Quebec Superior Court will not be heard until 2015; appeals will delay a final Decision possibly for a year or more.

   The PUB is asked to address the question: If the WMA is struck down, what will be the Firm capacity of the Muskrat Falls Project? Will Nalcor still have the generating capacity to meet the Island's demand if Muskrat's capacity is diminished and in the absence of Holyrood?

2. **Impact of the Energy Access Agreement (EAA).** The analysis completed by Nalcor, and submitted to the PUB, during the Muskrat Falls reference, did not include the 167 MW which must be delivered to Nova Scotia during the peak demand period of a Newfoundland winter.

   Nor did it reflect Nalcor's commitments under the Energy Access Agreement, specifically the "Variance" clause and the commitments under the "Balancing" Agreement. Nalcor has obligated the Province and committed most of its so-called 'surplus' power to Nova Scotia. The EAA commits, to Emera, a maximum of 1.8 TWh per year (1.2 TWh average) over a 21 year period. Emera has been given the right to take this power during the critical peak demand periods during any given day.

   In particular, if sales of additional energy or capacity are also made to Labrador Mining these commitments may conflict with domestic load growth, especially in winter, and require that NL build new high cost generation assets, in addition to Muskrat Falls.

   Emera's initial Application to the UARB states (para 437)

   "NSMPL (Emera) confirmed that there were no risks to ratepayers [of NS] from the non-delivery of energy by reason of any legal claim respecting the flow of water, or arising from the reduction of water flow itself on the Churchill River:

   "The contractual arrangements between Emera and Nalcor do not allow for non-delivery of energy. If energy is not delivered, Nalcor is liable to pay compensation damages to Emera. If the non-delivery is as a result of Government Action, the Government of Newfoundland and Labrador has guaranteed payment by Nalcor the compensation damages. Risks relating to Muskrat Falls are borne by Nalcor."

   It is not unreasonable to ask: do the contractual obligations contained in the EAA have the same legal basis as those which relate to the Nova Scotia Block? Do they 'de facto' constitute an additional commitment of Firm Power by Nalcor? Do these commitments, in any way, compromise available capacity to meet domestic load growth? Will the generating capacity at Holyrood be required if Nalcor's obligations under the EAA are met?

   Finally, on the subject of the EAA, why is there no agreement with Emera to provide for the return of a quantity of power from Nova Scotia to satisfy an emergency situation in this Province if the LIL should fail?

3. **The Labrador-Island Link (LIL).** The question of security and reliability in relation to the risks associated with a long distance transmission line from Muskrat Falls to the Avalon Peninsula has a direct bearing on any planning decision regarding Holyrood. Nalcor chose a risk level represented by a design criteria of 1:50 year event.

   The realities of the adverse maritime climate, the sub-sea crossing under the iceberg-scoured Strait of Belle Isle and the high wind and extreme icing conditions prevalent on high ground in southern Labrador, on top of the Long Range Mountains and across the Isthmus of Avalon cannot be ignored.

   The issues raised by Manitoba Hydro International, and noted by the PUB (pages 81-88) in its Decision on the Muskrat Falls reference, also demand further analysis.

   For greater specificity, I would draw your attention to the following excerpt from the October 2012 MHI Report (page 47):

   MHI notes that CAN/CSA C22.3 suggests a greater reliability of design to 1:150-year or 1:500-year return periods for lines of voltages greater than 230 kV which are deemed of critical importance to the electrical system. It is MHI's opinion the ± 350 kVdc and 315 kV ac lines proposed for the Lower Churchill Project be classified in a critical importance category due to their operating voltage and role in Nalcor's long term strategic plan for its transmission system and be designed to a reliability return period greater than 1:50 years.

   Many public and business groups have been reminded of the financial costs to people and business, of the power outages specifically, and the environment of uncertainty these outages create. I am surprised that more of them have not loudly expressed concern over the "...two-week worst case scenario..." (page 85 PUB Decision); the repair period for the LIL raised by MHI. Perhaps, already, some people think an extended outage can never happen again.

   Again, considerations of Holyrood are central to the risk associated with the LIL and the harsh winter environment which gives rise to that risk.

   We need to know if, as currently designed, the LIL represents an acceptable risk, taking all factors into account, and whether the long term maintenance of Holyrood is necessary to ameliorate that risk to an acceptable level. Does Nalcor have a back-up Plan if the LIL goes down. The statistical risk is just as applicable in the early years of the operation of the Muskrat Falls system as at some later date. Is it too late to influence changes to Nalcor's 1:50 year design period?

Finally, I want to note the proposed third line connecting the Avalon to available power in Central Newfoundland.

4. Nalcor has indicated that 176 MW of non- thermal capacity is available in Central Newfoundland.

   Public comment by Nalcor CEO Ed Martin suggested the third line is uneconomic. The comment seems contradictory to a prior submission to the PUB and suggests its inclusion in Hydro's Capital Budget was frivolous to begin with.

   The transmission line from Bay d'Espoir to the Western Avalon has a capacity of 319 MWs and according to Nalcor is "terminally constrained and unable to transfer the increased power". The construction of a new transmission line, says the Nalcor Submission, "will permit deliveries of 495 MW of hydroelectric generation to the Avalon Peninsula prior to the start of the first oil-fired unit at Holyrood."

   It also stated, on page 37 of its PUB Submission, that the new line will provide for "improved efficiency of the generators at Holyrood...reduced fuel consumption and in turn may reduce the potential for spill at hydroelectric facilities"

   The questions which arise are these: On what basis is the third line no longer needed? Why was the Project withdrawn from the Capital Budget of Hydro? Should NLH be ordered to reinstate a request for the PUB's approval of the line? Would the upgrade have reduced or eliminated the recent outages?

Mr. Chairman, no overhang of uncertainty ought to characterize these deliberations. No reasonable question, placed by legitimately concerned citizens, should go unanswered.

The PUB is not being asked to revisit consideration of the financial or technical feasibility of the Muskrat Falls Project. The public, I submit, is well aware that role was "untimely ripped" from the PUB when the Board failed to give the Government the answer it sought.

The PUB is the only duly constituted and impartial Agency, in this Province, equipped to assess these matters.

In the absence of an independent inquiry headed by a Supreme Court Judge, under the Public Inquiries Act, only the PUB can safeguard the public interest from being filtered by the Government or Nalcor.

Questions regarding the security and reliability of our power supply are not isolated to Hydro's management practices or the condition of the 'nuts and bolts' at Holyrood.

The power 'black outs' coupled with decisions by Nalcor have caused significant gaps in how Newfoundlanders once regarded their energy system and the level of confidence with which people regard their energy future now. These gaps need to be bridged.

It is time to stop the second guessing, to rid ourselves of the current environment of acrimony, mistrust and secrecy, to give light to the urgency for transparency and public scrutiny.

We need to have the certainty that no issue, whether related to the pre or post-commissioning of Muskrat Falls will be omitted from this investigation.

We need to be able to rely on the PUB for the protection it is designed to afford.

Finally, if the PUB, in its wisdom sees fit to expand the scope of its investigation, I would respectfully ask that it re-open the opportunity for interveners to apply and to engage in the more broadly focused Hearings that ensue.

Sincerely,

Desmond Sullivan

References for Filing:

1. Decision – Nova Scotia Utility and Review Board in the Matter of the Maritime Link Act
2. Supplemental Decision - Nova Scotia Utility and Review Board in the Matter of the Maritime Link Act
3. Water Management Agreement Application – Pre-filed Evidence -Appendix D October 27, 2009
4. Nalcor Correspondence re: availability of non-thermal energy generation October, 2013

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DECISION **2013 NSUARB 154**
M05419

NOVA SCOTIA UTILITY AND REVIEW BOARD

IN THE MATTER OF THE MARITIME LINK ACT

- and -

IN THE MATTER OF AN APPLICATION by **NSP MARITIME LINK INCORPORATED** for approval of the Maritime Link Project

BEFORE:	Peter W. Gurnham, Q.C., Chair Roland A. Deveau, Q.C., Vice-Chair Kulvinder S. Dhillon, P. Eng., Member
APPLICANT:	**NSP MARITIME LINK INCORPORATED** James H. Smellie, LL.B. René Gallant, LL.B. Daniel M. Campbell, Q.C.
INTERVENORS:	**PATRICK J. BATES** on his own behalf **CANADIAN WIND ENERGY ASSOCIATION** Shawna Eason Tom Levy Rodney V. Northey **CONSUMER ADVOCATE** John P. Merrick, Q.C. William L. Mahody, LL.B. **ECOLOGY ACTION CENTRE** Catherine Abreu Jamie Thomson **HERITAGE GAS** Michael Johnston **INDUSTRIAL GROUP** Nancy Rubin, Q.C. Maggie Stewart, LL.B. **LIBERAL CAUCUS OFFICE** Stephen McNeil, M.L.A. Andrew Younger, M.L.A.

LOWER POWER RATES ALLIANCE OF NOVA SCOTIA
Archie Stewart

MUNICIPAL ELECTRIC UTILITIES OF NOVA SCOTIA CO-OPERATIVE
Albert Dominie

NOVA SCOTIA POWER INCORPORATED
Terence Dalgleish, Q.C.
David Landrigan, LL.B.
Nicole Godbout, LL.B.

PC CAUCUS OFFICE
Jamie Baillie, M.L.A.
Craig McDonald

PORT HAWKESBURY PAPER LP
Bill Stewart

PROVINCE OF NOVA SCOTIA
(Departments of Energy and Environment)
Stephen T. McGrath, LL.B.
Ryan Brothers, LL.B.

SMALL BUSINESS ADVOCATE
E.A. Nelson Blackburn, Q.C.
Paul B. Miller, LL.B.

BOARD COUNSEL: S. Bruce Outhouse, Q.C.
Richard J. Melanson, LL.B.

HEARING DATE(S): May 28, 2013 to June 6, 2013

WRITTEN SUBMISSIONS: June 19, 2013

DECISION DATE: **July 22, 2013**

DECISION: **Maritime Link Project approved as lowest long-term cost alternative, conditional on obtaining from Nalcor the right to access Nalcor Market-priced Energy (consistent with the assumptions in the Application). See paragraphs 451 to 461.**

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1.0 INTRODUCTION

[1] This is a Decision of the Nova Scotia Utility and Review Board (the "Board") respecting an application of NSP Maritime Link Incorporated ("NSPML" or the "Applicant") filed on January 28, 2013, under the *Maritime Link Act*, S.N.S. 2012, c. 9 (the "*ML Act*") and the *Maritime Link Cost Recovery Process Regulations* (N.S. Reg. 189/2012) (the "*ML Regulations*") for approval of the Maritime Link Project and the Nalcor Transactions (the "Application").

[2] The Maritime Link Project refers to the design, construction, operation and maintenance of the Maritime Link transmission facilities, together with related transactions involving the delivery of energy, the provision of transmission services over the Maritime Link and the enabling of transmission service through Nova Scotia (the "ML Project"), as set out in 13 agreements dated July 31, 2012, between Emera and Nalcor, and other parties (referred to as the "Nalcor Transactions"), which will be described in greater detail below.

[3] Under the proposed ML Project, power and energy from the Muskrat Falls Hydro Electric Project will be delivered from Newfoundland and Labrador ("NL") to Nova Scotia ("NS").

[4] The *ML Regulations*, enacted by the Province of Nova Scotia, provide that the Board must approve the ML Project if two conditions are met:

> 5 (1) The Review Board must approve the Maritime Link Project if, on the evidence and submissions provided, the Review Board is satisfied that the project meets all of the following criteria:
>
> (a) the project represents the lowest long-term cost alternative for electricity for ratepayers in the Province;
>
> (b) 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.

[5] A total of 23 formal Intervenors responded to the Notice of Public Hearing (identified in Appendix A). A number of these parties were represented at the hearing by counsel. The following Intervenors participated at the hearing: the Consumer Advocate (the "CA"); the Small Business Advocate ("SBA"); Canadian Wind Energy Association ("CanWEA"); Ecology Action Centre ("EAC"); Heritage Gas Limited ("Heritage"); a group of 12 large industrial customers represented by counsel (the "Industrial Group"); the Lower Power Rates Alliance of Nova Scotia ("LPRA"); the Municipal Electric Utilities of Nova Scotia Co-operative ("MEUNSC"); the Nova Scotia Department of Energy, and Nova Scotia Environment (collectively referred to as the "Province" or "NSDOE"); Nova Scotia Power Inc. ("NSPI"), Nova Scotia Liberal Caucus ("Liberal Caucus"); Nova Scotia PC Caucus ("PC Caucus") and Port Hawkesbury Paper LP.

[6] S. Bruce Outhouse, Q.C., and Richard J. Melanson, LL.B., acted as Board Counsel.

[7] The Notice of Public Hearing was published in the Chronicle Herald and the Cape Breton Post on Saturday, February 2, 2013, Wednesday, February 6, 2013, and Saturday, February 9, 2013; and an Amended Notice of Public Hearing was published on Thursday, April 25, 2013. The hearing was held over nine days from May 28, 2013 to June 6, 2013, at Saint Mary's University, Loyola Academic Complex, Conference Hall L-290 in Halifax, Nova Scotia. The parties filed written submissions and reply submissions which were completed on June 19, 2013.

[8] In the advertised Notice of Public Hearing, the public was advised that they could file submissions with the Board outlining their views regarding the

Application. In response to this notification, the Board received 13 written submissions from the public (Appendix "C") and 10 individuals made presentations at the evening session on May 28, 2013 (Appendix "B"). The Board appreciates the time given by these speakers and members of the public to have their respective views made known.

[9] The views in the written submissions were split with approximately half supporting, and half opposing, the ML Project. Those supporting the ML Project highlighted that Nova Scotia would benefit from a reliable electricity source that would deliver energy at a stable price. Other supporters commented that the ML Project would help meet renewable energy requirements and also benefit Nova Scotia by helping to diversify its energy sources. Many submissions also identified how Nova Scotia would benefit as a result of jobs created from the construction of the ML Project.

[10] Those individuals opposing the Application identified concerns over the availability of Market-priced Energy (which is defined later in this Decision). Several submissions also expressed concern over capital cost overruns and higher than estimated operating and maintenance costs.

[11] During the evening session, similar benefits and concerns relating to the ML Project were identified.

[12] Some of the arguments in support of the ML Project were described by the following presenters.

[13] Barbara Pike, CEO of the Maritime Energy Association, which represents more than 300 member companies employing thousands of people, indicated her support for the ML Project in order to obtain diverse energy sources. She stated that

energy from Muskrat Falls is an important step to provide a rich mix of energy sources and energy options for Nova Scotia.

[14] Fred Morley, Executive Vice President and Chief Economist with the Greater Halifax Partnership, spoke about the security and supply price of energy. He discussed how the reduction of price risk and the provision of baseline power to replace coal will allow for further development of intermittent sources like wind and tidal energy. He also pointed to the economic benefit resulting from employment on the construction of the Nova Scotia portion of the ML Project.

[15] John Herron, who represented the Atlantica Centre for Energy, noted in his testimony that the cost of capital for infrastructure projects has never been cheaper and now is the best time to pursue such a project.

[16] Keith MacDonald represented the Cape Breton Partnership, which focuses on promoting Cape Breton as a place to do business. He indicated its support for the ML Project, specifically the economic benefits for Cape Breton and a future where Cape Breton can continue to play a role as an energy hub.

[17] Speakers Barry Alexander, Bill Black, Luciano Lisi, Barbara Clow, Gail Baikie and Roberta Frampton-Benefiel presented their views on why they believe the Application for the ML Project should not be approved. Some of the reasons focussed on the risks consistent with those identified in evidence by Intervenors, including the risk that Nova Scotia is being shortchanged with respect to the Supplemental Energy block that is intended to be a substitute for energy not delivered in the last 15 years of the Maritime Link's useful life. Many speakers echoed the written submissions and Intervenors' concerns on the availability of Market-priced Energy from Nalcor that is

required to realize the blended price projected in the Application. Several speakers commented that in order for the Board to determine the lowest long-term option there should have been a competitive Request for Proposal process. Other speakers expressed their concerns over the environmental and social effects of the ML Project in Newfoundland and Labrador and also whether the legal requirements of other jurisdictions would consider Muskrat Falls energy as "green".

[18] Mr. Black, former CEO of Maritime Life Insurance Company, also offered recommendations on how the Board should assess its decision. Mr. Black advised that the Maritime Link is going to get built "one way or the other" and so the issue the Board should consider, in his view, is whether the financial terms are the best that could be negotiated. Mr. Black noted that without Market-priced Energy from Nalcor the terms of the ML Project are not the best, and he recommended the proponents either offer a guarantee for the power or financial compensation to ratepayers if power is not available.

[19] The Board considered all the written submissions and the comments made during the evening session in making its Decision. The Board sincerely appreciates the time, effort and interest of those who have expressed their views on this important issue.

2.0 BACKGROUND

[20] NSPML is an indirect wholly owned subsidiary of Emera Inc. ("Emera"), and an affiliate company of NSPI. NSPML proposes to be responsible for building and operating the Maritime Link.

[21] Nalcor Energy ("Nalcor") is the provincial Crown Corporation responsible for developing and managing Newfoundland and Labrador's energy resources.

[22] The proposed ML Project will give Nova Scotia access to energy from Phase 1 of Nalcor's Lower Churchill hydroelectric development in Labrador ("Lower Churchill Project Phase 1" or "LCP Phase 1"). In their entirety, these projects will see the development and transmission of hydroelectric power from Muskrat Falls, on the Churchill River in Labrador, to the Island of Newfoundland via the Labrador-Island Link ("LIL"), then through the Maritime Link to Nova Scotia and through to New England.

[23] The ML Project will connect the electricity system of Newfoundland and Labrador to the electricity system of Nova Scotia, with a transmission link capable of transmitting up to 500 MW of electrical power.

[24] The transmission and related facilities comprising the Maritime Link will consist of a high voltage direct current ("HVDC") subsea cable system and related land-based equipment, near-shore grounding stations, direct current conversion stations, HVDC overhead transmission lines, substation improvements, and a 230 kV alternating current ("AC") transmission line between Granite Canal and Bottom Brook.

[25] The Maritime Link facilities will interconnect with the existing AC systems at Bottom Brook Substation in Newfoundland and Woodbine Substation in Nova Scotia. The HVDC transmission path from Bottom Brook to Woodbine consists of three main sections: a 142 km overhead section from Bottom Brook to the southwestern shore of NL near Cape Ray; a 170 km subsea section across the Cabot Strait; and a 47 km section from the shore near Point Aconi, NS to the Woodbine Substation.

[26] Connecting the HVDC link into the NL Hydro and NSPI transmission systems will require expansion of the Bottom Brook and Woodbine Substations, and additional transmission infrastructure in both NS and NL.

[27] The basic premise underlying the Nalcor Transactions is that NSPML will pay 20% of the LCP Phase 1 and the Maritime Link facilities' estimated total capital and operating costs in exchange for 20% of the estimated energy and capacity from Muskrat Falls (the "20 for 20 Principle"). This 20% of the energy and capacity has a duration of 35 years and, when combined with the five year Supplemental Energy (described later), is called the Nova Scotia Block ("NS Block").

[28] NSPML is seeking recovery of these costs from customers in Nova Scotia in exchange for providing Muskrat Falls energy to Nova Scotia customers.

[29] The Muskrat Falls Generation Station will be capable of producing up to 824 MW of electricity (4.93 TWh annual energy production). Nalcor requires part of this supply for Newfoundland and Labrador's own needs (i.e., including 40% or about 2 TWh to retire its Holyrood Generation Station). A portion of the remaining energy may be directed to meet Newfoundland and Labrador's future load growth, including that required to serve Labrador's growing mining industry.

[30] NSPML's 20% of the energy produced at Muskrat Falls will provide NSPI with contractually guaranteed annual access to the NS Block. After subtracting system losses, this represents an approximate firm capacity of 153 MW (i.e., 170 MW less line losses) of on-peak renewable electricity at the Woodbine Substation. This is estimated by NSPML to be 895 GWh of energy (i.e., just under 1 TWh). This annual amount of energy is equal to eight to ten percent of NSPI's current electricity sales to customers. The NS Block is dispatchable, which means NSPI can schedule and optimize when the energy is to be delivered to Nova Scotia, in accordance with the contractual terms governing this arrangement.

[31] The expected service life of the Maritime Link facilities is 50 years. NSPML will own 100% of the Maritime Link facilities for the first 35 years. After 35 years, ownership of the Maritime Link facilities will transfer to Nalcor. The terms of the agreement with Nalcor provide that Nalcor will supply NSPML with an additional block of electrical energy in the first five years of operation of the Maritime Link to compensate for this 15 year differential. This additional electrical energy is approximately 240 GWh per year and is known as Supplemental Energy ("Supplemental Energy"). Although the Supplemental Energy will be available during the winter months, it will not be available during the peak load hours in those months.

[32] The Supplemental Energy is calculated based upon the position that Nova Scotia customers should be in the same present value cost position as they would have been had the Maritime Link facilities been owned and depreciated for 50 years. For the purposes of this Decision, any reference by the Board to the NS Block includes the Supplemental Energy component (unless the context otherwise requires).

[33] The balance of the Maritime Link's 500 MW capacity would be available for sales to NSPI by Nalcor, or the energy could pass through Nova Scotia to buyers beyond the NS/NB border.

[34] On an annual basis, the Maritime Link is capable of transmitting more than 4 TWh of power, while the NS Block of firm power is less than 1 TWh. In addition to the fixed amount of power that must be delivered by Nalcor to NSPML on the Maritime Link (i.e., the NS Block, including the Supplemental Energy), NSPML states that Nova Scotia ratepayers will also have access to additional non-firm power from Muskrat Falls that can be purchased from Nalcor ("Nalcor Surplus Energy").

[35] Synapse elaborated on future additional energy from Nalcor as follows:

> The establishment of the Maritime Link would allow NSPI to purchase additional energy from Nalcor. In NSPML's analysis, this energy is assumed to flow to NSPI, is substantial in volume (averaging more than 10% of NSPI's needs), and is priced on a market basis, using a MA Hub (market price in New England) benchmark. Based on the pricing assumptions, the surplus energy appears to flow primarily during off-peak periods.
>
> [Synapse, Exhibit M-49, p. 32]

[36] NSPML stated that the additional energy may be purchased either from Nalcor (i.e., as Nalcor Surplus Energy from Muskrat Falls or as energy generated by Nalcor from other sources) or from other sources (including imports over the NS/NB transmission interconnection) (collectively referred to as "Market-priced Energy").

[37] As a result, NSPML asserted that the net impact to NSPI customers will be a blending of the ML Project costs (reflected in the NS Block, including Supplemental Energy) with the forecast costs reflected by the purchase of Market-priced Energy. NSPML stated that this will effectively result in a "blended cost of electricity" for NSPI customers, which has been depicted in Figure 4-4 of the Application:

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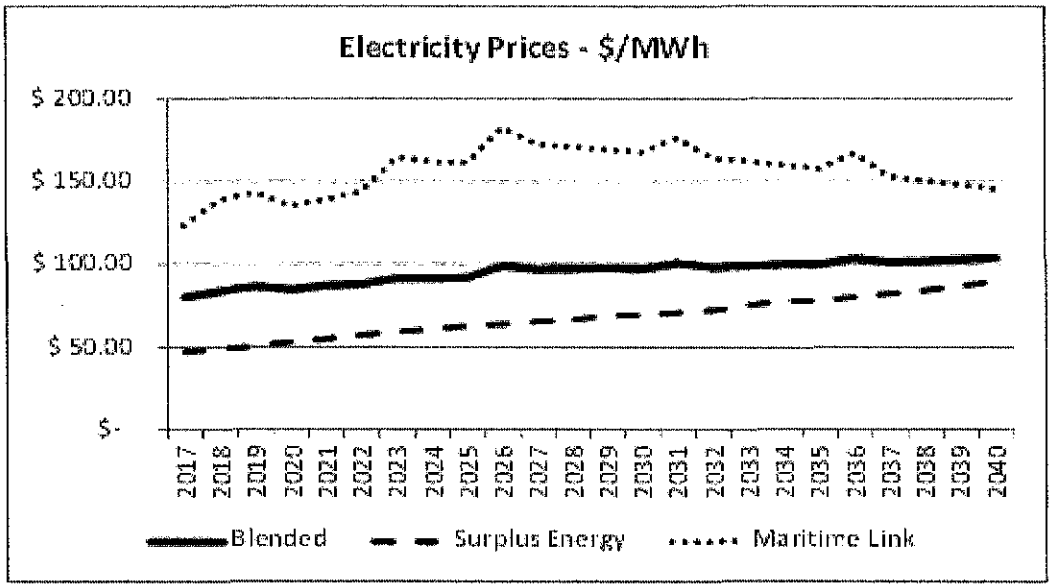
Figure 4-4 Weighted Average Electricity Prices Per MWh



[Application, Exhibit M-2, Figure 4-4, p. 92]

[38] Figure 4-4 was the topic of much testimony during the course of the hearing.

[39] Figure 4-4 shows the NS Block (including the Supplemental Energy) on the top dotted line. This line depicts the price needed to fully recover the costs to build the ML Project and operate it over the 35 year term. It is priced on a levelized basis at approximately $150/MWh or more, which is relatively expensive in today's environment.

[40] The dashed line depicted on the bottom of Figure 4-4 represents a rate estimated for purchasing Market-priced Energy. It starts at about $50/MWh and gradually increases over the 35 year term to about $90/MWh. This is an attractive rate for ratepayers. NSPML has assumed that the price of this energy would be determined on the basis of the Massachusetts market Hub price because the MassHub has a significant impact on the setting of market energy rates in Northeastern North America.

[41] The CA described how the blending of the rates in Figure 4-4 forms the fundamental basis of the Application:

> For the purpose of evaluating whether the project represents the lowest cost, the cost of the surplus electricity is blended with the cost of the Nova Scotia Block (see Figure 4-4, Application, p. 92). The premise is that NSPI will purchase enough of the lower priced surplus electricity that it will offset the high-priced Nova Scotia Block. It is the reduced cost that is advanced as qualifying as the lowest cost alternative.
>
> [CA Closing Submission, p. 2]

[42] In order to access markets in the Maritimes and beyond, Nalcor has negotiated transmission access through Nova Scotia for a 50 year period.

[43] The contractual terms in the Nalcor Transactions govern the delivery of the NS Block (including Supplemental Energy), as well as the transmission commitments made by Emera in favour of Nalcor.

[44] In addition to transmission access through Nova Scotia, the commercial agreements also require Emera to provide Nalcor with a transmission path through New Brunswick ("NB") and into New England, allowing Muskrat Falls energy to reach markets in the Northeastern United States.

[45] The execution of these foregoing agreements was followed, on November 30, 2012, with the conclusion of a Federal Loan Guarantee term sheet between the Governments of Canada, Nova Scotia and Newfoundland and Labrador, as well as Nalcor and Emera.

[46] On December 5, 2012, the Legislature of Newfoundland and Labrador enacted legislation to approve the Muskrat Falls Generation Station, the Labrador Transmission Assets ("LTA") and the LIL projects.

[47] On December 17, 2012, Emera and Nalcor entered into a Sanction Agreement enabling both parties to advance their respective projects.

3.0 LEGISLATION

3.1 ML Act and *ML Regulations*

[48] The ML Project is defined under the *ML Act* as follows:

> 2 (c) "Maritime Link Project" means the design, construction, operation and maintenance of the Maritime Link, together with the related transactions involving the delivery of energy, the provision of transmission services over the Maritime Link and the enabling of transmission service through the Province, as set out in a term sheet between Emera Incorporated and Nalcor Energy dated November 18, 2010; [Emphasis added]

[49] The *ML Act* provides that the Board has the general supervision of the ML Project and of an applicant in respect of the ML Project:

> 4 The Review Board has the general supervision of an applicant and the Maritime Link Project, and may make all necessary examinations and inquiries and keep itself informed as to the compliance by an applicant with the provisions of law and has the right to obtain from an applicant all information necessary to enable the Review Board to fulfil its duties.

[50] Further, a regulatory review process can be established by regulations made by Governor in Council:

> 6 (1) The Governor in Council shall, after consultation with the Chair of the Review Board, make regulations establishing a hearing and approval process and the criteria and conditions by which an application with respect to the Maritime Link Project is to be reviewed and considered for approval by the Review Board, which may include regulations
>
> (a) determining when a hearing is required;
>
> (b) establishing the subject-matter to be considered in a hearing;
>
> (c) setting out the criteria for approval or confirmation of an approval by the Board;
>
> (d) determining the matters to be decided in a hearing including, without limiting the generality of the foregoing, setting limits or parameters for which costs will be allowed or within which rates must be set;
>
> (e) establishing the timing of various steps of the hearing and approval process;
>
> (f) determining any other matter or thing relating to the hearing and approval process the Governor in Council considers necessary or advisable.

[51] The application and review process for approval of the ML Project is set out in ss. 5-7 of the *ML Regulations*:

Application and review

5 (1) The Review Board must approve the Maritime Link Project if, on the evidence and submissions provided, the Review Board is satisfied that the project meets all of the following criteria:

(a) the project represents the lowest long-term cost alternative for electricity for ratepayers in the Province;

(b) 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.

(2) An applicant must provide the Review Board with the best information and evidence available at the time to apply the criteria in subsection (1).

(3) In its approval, the Review Board may order any terms and conditions it considers necessary.

(4) The Review Board must make a decision under Section 5 no later than 180 days after the date the applicant submits an application.

(5) An application must include all of the following:

(a) a statement of the purpose of the Maritime Link Project, including the reasons for the project and the specific relief being requested of the Review Board;

(b) a summary of the commercial transactions with Nalcor Energy together with copies of all relevant agreements;

(c) engineering and design details sufficient to enable the Review Board to approve the Maritime Link Project in accordance with subsection (1);

(d) capital and operating cost estimates for the Maritime Link Project, including proposed capital structure and return-on-investment;

(e) capital and operating cost estimates for Muskrat Falls, Labrador transmission assets and the Labrador Island link, together with supporting engineering and design evidence;

(f) an analysis of lowest long-term cost alternatives to the Maritime Link Project;

(g) anticipated schedule of construction and in-service schedule for the Maritime Link, as contemplated under the Nalcor Transactions.

Variance with respect to approved costs

6 (1) If requested by an applicant, the Review Board must establish a variance with respect to the approved cost of the Maritime Link Project.

(2) The size of the variance must be set by the Review Board.

(3) If at any time there are Project costs that exceed the variance established under this Section, an applicant must apply to have the excess costs approved by the Review Board in accordance with Section 8.

Project report
7 (1) An applicant must file a project report on the Maritime Link Project containing the details required by subsection (2) with the Review Board:

(a) on or before December 31, 2013; or

(b) on or before another date the Review Board orders, as it considers necessary as a result of the progress of the Maritime Link Project.

(2) A project report must set out all the following for the Maritime Link Project:

(a) detailed engineering and design information;

(b) updated and current cost estimates and actuals;

(c) any material changes to any of the information submitted to the Review Board under Section 5.

[52] The Board notes that the Nalcor Transactions are defined in s. 2 of the *ML Regulations*:

"Nalcor Transactions" means the transactions with respect to the Maritime Link Project as set out in the Agreement dated July 31, 2012, between Emera, Nalcor Energy, the Government of Nova Scotia and the Government of Newfoundland and Labrador, and for greater certainty includes all of the following transactions as set out in agreements between Emera and Nalcor Energy:

(i) the development of the Maritime Link by Emera,

(ii) the provision to Emera of energy equivalent to 20% of the estimated capacity of the Muskrat Falls Generating Station,

(iii) the provision to Nalcor Energy of certain transmission rights through the Province,

(iv) the granting of transmission rights over the Maritime Link,

(v) the responsibility for operating and maintaining the Maritime Link,

(vi) the transfer of the Maritime Link to Nalcor Energy following a period of 35 years after energy is first delivered to Emera;

[53] The recovery of a rate, toll, charge or other compensation by an applicant (in this case NSPML) from NSPI (and, ultimately, from its ratepayers) is governed by ss. 4 and 8 of the *ML Regulations*:

Requirement for Review Board approval
4 (1) To obtain a rate, toll, charge or other compensation for services as defined under the *Public Utilities Act*, an applicant must first obtain an approval of the Maritime Link Project under Section 5.

(2) Once approved under Section 5, an applicant is entitled to recover Project costs through a rate, toll, charge or other compensation from Nova Scotia Power Incorporated in accordance with Section 8.

(3) An applicant who makes an application under this Section is not required to make a separate application under Section 35 or 35A of the *Public Utilities Act*, but once the Review Board has approved an assessment under Section 8, the applicant is subject to Sections 35 and 35A of the *Public Utilities Act* with respect to any new expenditures.

. . .

Assessment and costing approval
8 (1) Before receiving energy under the Nalcor Transactions, an applicant must set an assessment against Nova Scotia Power Incorporated for the recovery of the all approved Project costs, and must apply to the Review Board for an approval of the assessment under Section 64 of the *Public Utilities Act*.

(2) Nova Scotia Power Incorporated is entitled to recover through its rates any assessment approved by the Review Board in respect of the Maritime Link Project.

[54] Section 3 of the *ML Regulations* provides that any applicant is deemed to be a public utility:

Designation as public utility
3 An applicant is deemed to be a public utility within the meaning of the *Public Utilities Act* and the *Public Utilities Act* applies to an applicant.

[55] Section 5 of the *ML Act* sets out the application of the *Public Utilities Act*, R.S.N.S. 1989, c. 380 (the "*PUA*"):

5 (1) Notwithstanding the regulations, Section 54 of *Public Utilities Act* does not apply with respect to construction of the Maritime Link Project by an applicant in territory already served by a public utility of like nature, as that territory exists at the time this Act comes into force.

(2) For greater certainty, where an applicant has been made subject to the *Public Utilities Act* by regulation, for the purpose of that Act and in particular Section 64 of that Act, the transmission of electricity by the applicant is a service to which Section 64 of that Act applies.

(3) Notwithstanding Section 117 of the *Public Utilities Act*, where there is a conflict between this Act or the regulations and the *Public Utilities Act* or the regulations made pursuant to that Act, this Act and the regulations prevail.

3.2 *Electricity Act* and *Renewable Electricity Regulations*

[56] In April 2010, the Province released its Renewable Electricity Plan, which sets out a detailed program to move Nova Scotia away from carbon-based electricity towards greener, more local sources. The Renewable Electricity Plan includes conservation and efficiency programs as well as a transition to renewable energy sources. In October 2010, the Province released the "Update and Preliminary Guide on Renewable Electricity in Nova Scotia" (unless the context requires otherwise, the Plan and Update are referred to collectively in this Decision as the "Renewable Electricity Plan").

[57] On May 11, 2010, amendments to the *Electricity Act* received Royal Assent. This was followed by draft regulations and public consultations leading to a proclamation of the amended *Electricity Act* and enactment of the *Renewable Electricity Regulations* in October 2010. These *Regulations* established a provincial target of supplying at least 25% of electricity sales with renewable electricity by the year 2015 ("RES 2015").

[58] Effective January 17, 2013, by Order in Council 2013-13, the Governor in Council amended the *Renewable Electricity Regulations* to add a renewable electricity standard of 40% by 2020 ("RES 2020") and to enable the purchasing of qualifying power from Muskrat Falls (in addition to other sources). The RES 2020 standard specifically refers to inclusion of 20% of the electricity generated by Muskrat Falls:

> **Renewable electricity standard 2015**
> 6 (1) Each year beginning with the calendar year 2015 until 2020, each load-serving entity must supply its customers with renewable electricity in an amount equal to or greater than 25% of the total amount of electricity supplied to its customers as measured at the customers' meters for that year.
>
> (2) To meet the renewable electricity standard in subsection (1), NSPI must

(a) continue to supply at least 5% of its total annual sales from independent power producers; and

(b) acquire at least 300 GWh from independent power producers in addition to the renewable low-impact electricity required to meet the requirements of Sections 4 and 5.

(3) In planning for meeting its obligations under subsections (1) and (2) NSPI must not include electricity from distribution system connected renewable energy generators.

(4) In meeting its obligations under subsections (1) and (2), NSPI may include other sources of renewable electricity, including:

(a) contributions from distribution system connected renewable energy generators;

(b) contributions of 150 GWh or less from co-firing non-primary forest biomass at its generation facilities;

(c) contributions from renewable electricity generating facilities that it owns or operates.

(5) To meet the renewable electricity standard in subsection (1), a municipal electric utility that purchases any of its electricity supply from a supplier other than NSPI must ensure that a minimum of 25% of that non-NSPI electricity supply is renewable electricity.

(6) Electricity supply purchased by a municipal electric utility that is sold to NSPI as spill energy under the Wholesale Market Non-Dispatchable Supplier Spill Tariff counts towards the municipal electric utility's renewable electricity standard under subsection (1) if

(a) an equivalent amount of electricity is purchased from NSPI as backup/top-up energy under the Wholesale Market Backup/Top-Up Service Tariff; and

(b) the supply [is] consumed within the same calendar year as it is purchased.

Renewable electricity standard 2020
6A (1) Each year beginning with the calendar year 2020, each load-serving entity must supply its customers with renewable electricity in an amount equal to or greater than 40% of the total amount of electricity supplied to its customers as measured at the customers' meters for that year.

(2) NSPI must meet the renewable electricity standard in subsection (1) by

(a) continuing to meet the requirements in clauses 6(2)(a) and (b);

(b) continuing to meet the requirements of subsection 6(4); and

(c) <u>directly or indirectly acquiring, to deliver to customers in the Province, 20% of the electricity generated by the Muskrat Falls Generating Station if the Muskrat Falls Generating Station and associated transmission infrastructure is completed and in normal operation and the UARB has approved an assessment against NSPI under the *Maritime Link Act* and its regulations</u>.

(3) In planning for meeting its obligations under subsections (1) and (2) NSPI must not include electricity from distribution connect renewable energy generators.

(4) To meet the renewable electricity standard in subsection (1), a municipal electric utility that purchases any of its electricity supply from a supplier other than NSPI must ensure that a minimum of 40% of that non-NSPI electricity supply is renewable electricity.

(5) Electricity supply purchased by a municipal electric utility that is sold to NSPI as spill energy under the Wholesale Market Non-Dispatchable Supplier Spill Tariff counts towards the municipal electric utility's renewable electricity standard under subsection (1) if

(a) an equivalent amount of electricity is purchased from NSPI as backup/top-up energy under the Wholesale Market Backup/Top-Up Service Tariff; and

(b) the supply is consumed within the same calendar year as it is purchased.

[Emphasis added]

3.3 *Environment Act, Canadian Environmental Protection Act*, and Associated Agreements.

[59] The *Nova Scotia Environment Act* places restrictions on emissions. *Air Quality Regulations* under the *Act* establish the following future limits on emissions from electricity production:

- Sulphur dioxide (SO_2) emissions must not exceed 36,250 tonnes per year by 2020.
- Nitrogen Oxide (NO_x) emissions must not exceed 14,955 tonnes per year by 2020.
- Mercury (Hg) emissions must not exceed 35 kg per year by 2020.

[60] *Greenhouse Gas Emissions Regulations*, under the *Environment Act*, caps carbon dioxide emissions from all facilities in Nova Scotia at 7.5 megatonnes by 2020 - a reduction of about 25% from 2010 levels.

[61] In 2005, the Government of Canada added carbon dioxide ("CO_2") to the *Canadian Environmental Protection Act's* list of toxic substances, and began work on a federal framework for reducing greenhouse gas ("GHG") emissions from electricity generation. New federal regulations, proclaimed in September 2012, require an additional 3.0 megatonnes reduction in GHG emissions in Nova Scotia by 2030.

[62] As noted in the Application, federal regulations also mandate coal-fired plant closures no more than 50 years after they first went into service. The same regulations require any new coal-fired plants to meet an emissions performance standard equivalent to the most modern combined cycle natural gas generating station.

[63] However, the Provincial and Federal Governments have agreed to an equivalency agreement which would achieve similar emissions targets as the new federal regulations, but without imposing specific closure dates based solely on plant age. Instead, NSPI can base the timing of its plant closure decisions on normal system planning considerations.

4.0 COMMERCIAL AGREEMENTS

[64] The relationship between NSPML, Emera, Nalcor, NSPI and other affiliated companies is governed by a complex set of agreements.

[65] As part of its Application, NSPML has requested confirmation from the Board that the ML Project and the Nalcor Transactions are supported by a reasonable and comprehensive set of commercial agreements.

[66] For the purposes of this Decision, the Board has summarized the "Commercial Agreements" comprising the Nalcor Transactions as follows:

1. Maritime Link Joint Development Agreement ("MLJDA") – Establishes the Joint Development Committee and governance structure for the ML Project; Provides for pre-sanction activities and sharing of related costs; Provides for project sanction in accordance with the Term Sheet; Provides for the basis of design of the Maritime Link and project implementation; Details the terms for development of the Maritime Link and sharing of cost overruns.

2. Energy and Capacity Agreement ("ECA") - Provides for delivery of the NS Block during the initial term (35 years); Provides for a subsequent term(s) should Nalcor and Emera arrive at mutually agreeable terms including price.

3. Maritime Link (Emera) Transmission Service Agreement ("Emera TSA") - Establishes the transmission rights for delivery of the NS Block and related assignment provisions in favour of Nalcor to enable delivery of the NS Block to the delivery point (Woodbine, NS).

4. Maritime Link (Nalcor) Transmission Service Agreement ("Nalcor TSA") - Provides for the establishment of all remaining transmission rights over the Maritime Link in favour of Nalcor for export/import purposes.

5. Nova Scotia Transmission Utilization Agreement ("NSTUA") - Establishes the commitments by Emera to schedule and deliver energy for Nalcor through NS on a pay-as-you-go basis for the initial term referred to in the ECA; Establishes the terms for transmission service for a subsequent term or during the 15 years following the initial term, as applicable.

6. New Brunswick Transmission Utilization Agreement ("NBTUA") - Provides for the use of the Bayside Transmission Rights on a pay-as-you-go basis while the Bayside Rights are available to Emera; Provides for equivalent rights through NB on a pay-as-you-go basis once the Bayside Rights are no longer available to Emera; In both cases, provides Nalcor with a financial back-stop should the rights not be available for Nalcor's use in accordance with the Term Sheet.

7. MEPCO [Maine Electric Power Company, Inc.] Transmission Rights Agreement ("MEPCO TRA") - Provides for the use of the MEPCO Transmission Rights

on a pay-as-you-go basis if required by Nalcor; Provides for an absolute assignment of the MEPCO Transmission Rights to Nalcor (if requested by Nalcor).

8. Interconnection Operators Agreement ("IOA") - Establishes the terms regarding safety, reliability and operability of the interconnection between the Newfoundland and Labrador and Nova Scotia bulk energy systems; Provides for an Interconnection Operators Committee to implement the provisions of the Agreement; Provides the framework for agreements on reserve sharing, emergency energy and regional generation adequacy reviews.

9. Joint Operations Agreement ("JOA") - Establishes the Joint Operations Committee for the transmission assets; Provides for standards of operation for the transmission assets; Provides the mechanism for 80/20 sharing of operating costs of all project assets; Establishes the conditions for the transfer of the Maritime Link to Nalcor after 35 years following First Commercial Power under the ECA.

10. Newfoundland and Labrador Development Agreement ("NLDA") - Establishes the Joint Development Committee for the non-Maritime Link assets; Provides the mechanics related to the funding of the LIL; Establishes the capital structure and rate of return for Emera's investment in the LIL, in accordance with the Term Sheet.

11. Labrador-Island Link Limited Partnership Agreement ("LILPA") - Establishes the structure for the partnership and how the partnership is managed; Provides the mechanics for distributions to the partners after first commercial power.

12. Supplemental Agreement - Serves as a formal memorandum of certain possible future activities and transactions referred to in the Term Sheet to facilitate

future discussion between Nalcor and Emera; Contains non-binding provisions from the Term Sheet relating to the possible provision of additional short-term energy to Emera and provisions relating to a possible Maritime Link Expansion and a possible Maritime Link Redevelopment.

13. Inter-Provincial Agreement – NS and NL working together in cooperation to ensure continued and ongoing success of the formal agreements; provides for indemnification in the event damages are caused by certain government actions.

[67] In addition to the Nalcor Transactions, the ML Project is also impacted by other commercial contracts, including the Federal Loan Guarantee, the Sanction Agreement and other agreements executed subsequent to the original Nalcor Transactions.

[68] On November 30, 2012, the Federal Loan Guarantee term sheet was executed between the Governments of Canada, Nova Scotia and Newfoundland and Labrador, as well as Nalcor and Emera.

[69] The Federal Loan Guarantee ("FLG") requires that the Government of Canada fulfill any payment obligations of NSPML or Nalcor with respect to their respective projects, should either of them fail to honour its debt agreement with an institutional lender. The intent of the FLG is to enhance credit by substituting the Government of Canada creditworthiness for that of NSPML or Nalcor, as the case may be, to ensure that the project debt receives Canada's AAA credit rating. As described later in this Decision, the Government of Canada's commitment to a FLG ensures a materially lower cost of debt for the entire project.

[70] On December 17, 2012, Emera and Nalcor signed a Sanction Agreement enabling both parties to advance their respective projects, subject to further processes depending on the outcome of this hearing. The Sanction Agreement also amended certain of the original Commercial Agreements referenced above, in particular the MLJDA. At the same time, the parties signed a Project Oversight Agreement which created a joint committee to oversee the timely completion of the conditions precedent to the FLG.

[71] Of particular importance for NSPI and its ratepayers, NSPML and NSPI executed an Agency and Service Agreement ("ASA") to reflect the relationship between the two companies. In effect, this agreement provides that NSPI has the obligation to carry out most of the responsibilities of NSPML under the Nalcor Transactions. Among other things, NSPI will provide transportation, scheduling and related services for the Maritime Link; facilitate the transmission of Nalcor Surplus Energy through Nova Scotia; and take energy from NSPML put back to Bayside Power by Nalcor pursuant to the NBTUA.

[72] Finally, NSPML and Bayside Power L.P. signed a Backstop Energy Agreement whereby NSPML assumes Bayside's obligations, when required to do so by Bayside, if Nalcor puts electricity to Bayside pursuant to the NBTUA and the MEPCO TRA. This same obligation can be put by NSPML to NSPI pursuant to the ASA.

5.0 ISSUES

[73] Pursuant to the Final Issues List that applied to this proceeding, the Board considers that the issues that must be addressed in this Decision are as follows:

1. Does the ML Project represent the lowest long-term cost alternative for electricity for ratepayers in the Province?

2. Is the ML Project consistent with obligations under the *Electricity Act*?

3. Is the ML Project consistent with any obligations governing the release of greenhouse gases and air pollutants under the *Environment Act*, the *Canadian Environmental Protection Act* and any associated agreements?

4. Are the engineering and design details included in the Application sufficient to enable the Board to approve the ML Project?

5. Should the capital and operating cost estimates for the ML Project be approved, including the capital structure and return-on-investment?

6. What variance, if any, should be established by the Board with respect to the approved cost of the ML Project?

7. Will NSPI ratepayers receive benefits from the ML Project commensurate with the risks and costs they will bear if the ML Project is approved?

8. Do the ML Project and Nalcor Transactions comply with applicable provisions of NS Power's Code of Conduct governing Affiliate Transactions?

9. If the Board approves the ML Project, should it order any terms and conditions in its approval?

10. Do the *ML Act* and *Regulations* authorize or require the Board to approve the Nalcor Transactions and related transactions?

11. Are the ML Project and Nalcor Transactions supported by a reasonable and comprehensive set of commercial agreements?

12. Does the *ML Act* authorize or require the Board to approve the transfer of the Maritime Link to Nalcor, and the sale of the Woodbine Upgrades to NSPI, following a period of 35 years after energy is first delivered to NSPML?

13. What schedule should the Board order for project reports, if any, on the progress of the ML Project?

14. Does the OATT need to be amended to incorporate or otherwise accommodate the provisions of the NSTUA?

15. How does the provision for delivery of energy other than the NS Block affect the distribution of benefits, costs and risks among the parties involved in the ML Project, the Nalcor Transactions, and related transactions, including whether Nova Scotia ratepayers are subsidizing transactions?

16. Will the ML Project result in a requirement for increased reserves to meet the reliability standards and criteria?

17. Are there contractual obligations, including water rights issues, that would serve as an impediment to NSPI obtaining the NS Block?

6.0 ANALYSIS AND FINDINGS

6.1 Does the ML Project represent the lowest long-term cost alternative for electricity for ratepayers in the Province?

6.1.1 Analysis of Alternatives

[74] Subject to satisfying the requirements of the *Electricity Act* and emissions standards under environmental legislation, the ML Project must be approved under s. 5(1)(a) of the *ML Regulations* if the "project represents the lowest long-term cost alternative for electricity for ratepayers in the Province".

[75] The burden of proof is on NSPML to show, on a balance of probabilities, that the ML Project represents the lowest long-term cost alternative for electricity for ratepayers in Nova Scotia.

[76] The Board notes that, under s. 5(1)(b) of the *ML Regulations*, NSPML must also show that the ML Project is consistent with the obligations under the *Electricity Act* and any obligations governing the release of greenhouse gases and air pollutants. While these issues are canvassed in greater detail later in this Decision, the Board is satisfied that, for the purposes of the present discussion, the alternatives canvassed by NSPML and the Intervenors all substantively comply or can be made to comply by the Minister with such obligations (i.e., they all substantively meet the RES

requirements and greenhouse gases and air pollutants targets outlined in the respective legislation).

[77] NSPML evaluated the ML Project and other alternative scenarios by measuring the net present value ("NPV") of the alternatives and selecting the option with the lowest NPV across a range of sensitivities.

[78] In an attempt to put some perspective on the use of forecasts and projections, the Board considered the comments of MPA Morrison Park Advisors Inc. ("Morrison Park"), which it found to be instructive in its review of the Application:

> A very significant component of the work of this Review involved the use of forecasts, projections and estimates, and in particular those provided by the Applicant in evidence and in response to information requests. ... It is critical to point out, however, the fundamental uncertainty that underlies many of the projections in question, particularly as they extend out not only years, but decades. Useful forecasts for the near to medium term are typically based on the belief – sometimes proven by subsequent events to be erroneous – that the future will consist of incremental changes to the practices of the past. However, the longer the time horizon of the forecast, the more likely that changes will cease to be incremental, and hence become truly unpredictable. What may appear to be reasonable today may at some point in the future – with the benefit of hindsight – look like a terrible mistake, or a massive stroke of luck. Prices change, technology changes, market dynamics change, the relative cost of goods changes: all in unpredictable ways over time.
>
> Technological advances, in particular, can render assumptions obsolete even in relatively short periods of time. ...
>
> There is a significant danger in assuming that a view of the future from the perspective of today will be very accurate. All such assumptions should be approached with humility, and treated with respect as the best available basis for decision-making, but without claiming them to be more than what they are. Decisions cannot be made without taking a view of the future, but the future may prove unwilling to agree with the forecasts made of it.
>
> It is commonplace that commercial transactions are analyzed using mathematical models, often providing a degree of precision measured in decimal points, which sometimes gives the illusion of accuracy or predictive power. We have used such models in this Review. However, these models are only as accurate as the assumptions about the future that underlie them. Since those assumptions must be given a broad range because of the difficulty inherent in predicting the future, especially over decades, the models should and do result in outputs with an equally broad range. This means that mathematical models sometimes may be capable of excluding certain decision options from the realm of reasonable commercial choice, but cannot always point to a single preferred outcome among several. In these case, decisions still must be made, but they must be rendered on the basis of judgement.

Commercial decisions are ultimately about judgement, and judgement is extremely difficult to quantify.

[Morrison Park, Exhibit M-46, pp. 12-13]

[79] In its Application, NSPML described the methodology which it used for the alternatives analysis:

6.3 Alternatives Analysis
NSPML retained Ventyx to conduct the alternatives analysis. Ventyx used the long-term generation planning tool Strategist®, a software model developed by Ventyx, an ABB Company. It has been regarded as the industry standard for generation planning for more than twenty-five years with an extensive client base in North America and abroad. Strategist® is used for unit dispatch and production costing as well as resource optimization. NS Power has used Strategist® analyses as part of the business case for numerous capital projects submitted for UARB approval. The software calculates the net present value of the costs of comparable alternatives

The objective of the study was to determine which alternative provides the lowest long-term cost by comparing the net present value of the Maritime Link Project costs to those of the other alternatives. The alternative with the lowest net present value of costs is the lowest cost alternative.

Sensitivities are run on variables that could change the outcome of the analysis to determine if, under changing conditions, the low cost alternative remains the right choice. Typical sensitivities that are considered include changing load forecasts and power and fuel prices. This approach determines the robustness of the alternatives under a variety of future scenarios.

Strategist® begins by calculating results for a Planning Period and then carries through the assumptions for the full Study Period. Strategist® first models a Planning Period for 25 years. The Study Period then includes costs beyond the 25 year Planning Period to account for differences in the useful life of capital investments. In order to ensure that an alternative is not biased by capital investments made late in the Planning Period, it is important to compare the results of the Study Period to truly determine which alternative is lowest cost. The Study Period reflects which alternative is truly lower cost in the long-term. This is consistent with how NS Power has approached long-term planning in previous submissions to the UARB.

Ventyx modeled the Nova Scotia system from 2015 to 2040 using input assumptions provided by NS Power. The database was developed by NS Power under a non-disclosure agreement with NSPML. This database is based on existing databases that were used in the 2007 and 2009 integrated resource plans with updates to reflect current forecasts and recent changes to the power system.

These input assumptions included load forecast, demand side management assumptions, fuel forecasts, generating unit information, emissions requirements and financial assumptions. ...

...

> Once the input assumptions were finalized, the model was offered the different alternatives to determine the lowest long-term cost option to meet the requirements described in the Regulations. In solving for the lowest long-term cost, the Strategist® model must also solve for environmental emissions factors, planning reserve, energy and capacity requirements, and renewable requirements.
>
> [Application, Exhibit M-2, pp. 117-119]

[80] Based on its preliminary screening analysis, NSPML determined that all but two alternatives should be eliminated from the alternatives analysis by the Strategist modeling tool. It proceeded to conduct an NPV analysis of the ML Project, an "Indigenous Wind" option and an "Other Import" option.

[81] The Indigenous Wind and Other Import alternatives, as postulated by NSPML, were succinctly described by the CA/SBA's consultant Levitan:

> The Indigenous Wind alternative is oriented around the quantity of wind energy required to meet Nova Scotia's renewable electricity standard ("RES") of 40% renewable electricity by 2020. Under the Base Load scenario (which the Applicant puts forth as the baseline), NSPI estimates that 425 MW of installed wind capacity will be required to achieve the RES target. The initial block of incremental wind capacity was assumed to be online in January 2019, a year ahead of the 40% requirement. To meet the increase in RES resources needed due to load growth, three 50 MW additions are included in subsequent years. For the Low Load scenario, only 250 MW of wind is installed to meet the 2020 RES target. ... Gas-fired generation units (simple and combined cycle) are added over the forecast period to supplant coal generation, as required to meet declining annual emission caps. ...
>
> The Other Import alternative was defined to have the same characteristics as [the Maritime Link], but imports sourced from Quebec or New England instead of Labrador-Newfoundland. With the Other Import alternative, Nova Scotia obtains approximately the same quantity of firm import capacity as [the Maritime Link], 159.6 MW, with the same commencement date, but through reinforcement of the transmission interconnection with New Brunswick. The Other Import alternative was assumed to also offer the opportunity to purchase market energy when economic, up to 500 MW total. The [transmission] infrastructure improvements were assumed to be identical for both the Base Load and Low Load scenarios.
>
> [Levitan, Exhibit M-45, p. 9]

[82] With respect to the Indigenous Wind alternative, NSPML estimated that with the addition of 575 MW of wind under the "Base Load" scenario, there could be up to 1,110 MW of total wind on the Nova Scotia system. It submitted that adding this

much wind to the system will pose reliability concerns related to the characteristics of this energy resource.

[83] NSPML stated in its Application that system requirements will require some level of capital investment in the form of integration costs, depending on the penetration levels of wind generation. These costs include investment in new conventional generating capacity to maintain planning reserves and to address needs for "two shifting or fast acting generation", investment in transmission upgrades, and the deployment of energy storage and load shifting programs to complement conventional generation for managing wind variability and wind ramps. In its modeling, NSPML estimated these wind integration costs for incremental wind above RES 2015 as ranging from $48/MWh for "Base Load" to $61/MWh for "Low Load": see Undertakings U-1 and U-42.

[84] In terms of the Other Import alternative, NSPML retained WKM Energy Consultants Inc. ("WKM"), whose principal William K. Marshall was New Brunswick's former System Operator and who has an extensive knowledge of the Maritimes' transmission infrastructure and system requirements, to determine what infrastructure was needed:

> ...NSPML retained WKM Energy Consultants (WKM) to determine what transmission infrastructure would be required to get the same benefit and opportunity the Maritime Link provides through New Brunswick. Specifically, WKM was asked to determine the cost of adding transmission infrastructure to the west of Nova Scotia so that NS Power could have a firm 165 MW transmission path and the opportunity to purchase additional energy up to 500 MW less the firm portion. ...
>
> WKM's analysis shows that the total estimated upgrade cost to develop a new 500 MW transmission interconnection between Nova Scotia and neighboring jurisdictions is $1.3 billion. Of this total amount, WKM estimates based on FERC [Federal Energy Regulatory Commission] principles that Nova Scotia would be required to pay a minimum of $905 million. ...
>
> [Application, Exhibit M-2, p. 124]

[85] The Other Import alternative assumed energy sourced outside of Nova Scotia would reflect New England or MassHub market rates, plus applicable tolls through New Brunswick, and line losses. If importing from New England, Nova Scotia would be required to pay MassHub market prices for the energy, as well as exit fees from the New England market, and would be required to obtain a firm transmission reservation from Maine into New Brunswick to secure a path for any energy purchases [Application, Exhibit M-2, pp. 124-125].

[86] Based on its Strategist analysis, NSPML concluded that the ML Project represents the lowest long-term cost alternative for electricity for Nova Scotian ratepayers.

[87] A summary of NSPML's initial NPV results, as outlined in its Application, are described as follows:

	Maritime Link	**Other Import**	**Indigenous Wind**
Base Load Study Period ($M PV)	16,209	16,496	18,182
Low Load Study Period ($M PV)	12,221	12,753	13,244

[88] Through IRs (Synapse IR-11), the comparable scenarios NSPML ran under the 25 year Planning Period ("Planning Period") were presented, with the following results:

	Maritime Link	**Other Import**	**Indigenous Wind**
Base Load Planning Period ($M PV)	10,776	10,914	11,643
Low Load Planning Period ($M PV)	8,942	9,187	9,264

[89] A significant focus at the hearing was the ability of NSPML to pass the lowest long-term cost test without the Market-priced Energy. An undertaking was requested to test robustness under such a worst case scenario. In Undertaking U-11, NSPML provided its analysis for the Maritime Link option without Market-priced Energy, as compared to the Indigenous Wind alternative under a "Base Load" scenario. The Board has compiled those results in the following table to include the Other Import alternative as NSPML had presented in its Application:

Base Load Cases	Maritime Link	ML No Surplus	Indigenous Wind	Additional Cost (Benefit)	Other Import	Additional Cost (Benefit)
Planning ($M PV)	10,776	11,482	11,643	161	10,914	(568)
Study ($M PV)	16,209	17,631	18,182	551	16,496	(1,135)

[90] The Province engaged Power Advisory LLC ("Power Advisory") "to assess the economic merits of the Maritime Link and the associated delivery of renewable energy from the Muskrat Falls Hydroelectric [Project] ... relative to other alternatives".

[91] Power Advisory concluded that the ML Project is less expensive than either of the two primary alternatives. On an NPV basis, the ML Project was projected to be $309 million less expensive (in 2017 dollars) than the Hydro Quebec Contract scenario (i.e., Other Import), and $1.346 billion less expensive than the Domestic Generation scenario (i.e., Indigenous Wind), over the 35 year term of the Commercial Agreements [Undertaking U-37].

[92] Board Counsel retained Synapse Energy Economics, Inc. ("Synapse") "to analyze the economics of the proposed Maritime Link project in comparison to alternatives including but not limited to the specific alternatives" modeled by NSPML.

[93] Synapse also conducted a Strategist analysis of the alternatives.

[94] Board Counsel also retained Morrison Park "to provide an opinion as to the fairness, from a financial point of view, of the [ML Project] to ratepayers in Nova Scotia". As part of its engagement, Morrison Park considered the levelized unit electricity cost ("LUEC") of the amount of power required to satisfy Nova Scotia's RES requirements for the foreseeable future. Morrison Park specifically compared the ML Project against the Indigenous Wind alternative (which it called the "Status Quo" in its report). As noted later in this Decision, Morrison Park eliminated the Other Import option from its consideration because there is currently no commercial agreement in place (or even proposed) for the provision of such energy.

[95] Finally, the CA and SBA retained Levitan & Associates, Inc. ("Levitan") to conduct an "examination of the economic analysis of the [ML Project] and the project alternatives", as well as to review the commercial terms between NSPI and Nalcor. Levitan relied on NSPML's Strategist results, but conducted its own non-Strategist analysis of the impact of various sensitivities. The CA also retained Resource Insight, Inc. ("Resource Insight"), whose review included the load forecasts and wind integration costs used by NSPML.

[96] Synapse, Power Advisory, Levitan and Resource Insight are all Boston area consulting firms which provide advice to clients on a range of issues in the electricity sector, including infrastructure, regulatory and environmental aspects. Morrison Park is a Canadian investment banking advisory firm.

[97] Some of the consultants' evidence respecting the alternatives analysis had weaknesses compared to other consultants who conducted a more thorough analysis. Power Advisory's analysis was based primarily on data provided by NSPML.

As a result, Power Advisory's Report lacked the type of independent review that would have given more insight into the various alternatives.

[98] For its part, Levitan's analysis was limited to a review of the impact of specific sensitivities on the NPV of the ML Project and of the alternatives. While its Report did give the Board a better appreciation of the potential impact of various assumptions made by NSPML, Levitan, ultimately, did not produce a comprehensive alternative or a range of scenarios that demonstrated a least-cost option to the ML Project was reasonably possible.

[99] However, the Board found the evidence of NSPML and Synapse to be the most useful in focussing on the issue of the alternatives analysis. Their evidence provided useful data on completed alternative scenarios, which were tested across a range of sensitivities. Accordingly, the Board assigns more weight to the evidence of NSPML and Synapse.

[100] The Board also places significant weight on the evidence of Morrison Park. Based on the scope of its specific engagement, Morrison Park provided a balanced high level review of the alternatives, which greatly assisted the Board by providing an important context to the consideration of the relevant issues.

[101] In its prefiled evidence, Synapse identified a number of concerns it had with NSPML's analysis of the alternatives.

[102] Synapse noted that NSPML modeled the Other Import alternative as requiring the same capacity (i.e., 500 MW) as that provided by the Maritime Link. In Synapse's opinion, this assumption resulted in an alternative that exceeded Nova

Scotia's requirements in the future and did not tailor the Other Import alternative to optimize its contribution to NSPI's bulk power system.

[103] It also concluded that NSPML's alternative scenarios were not the result of any form of resource planning optimization. Synapse noted that NSPML did not do any explicit modeling of any hybrid alternatives combining Nova Scotia wind and external renewable energy imported across the NB border.

[104] Synapse modeled its own Strategist analysis, layering a number of adjustments to NSPML's assumptions, across a series of computer modeling runs. First, Synapse concluded that NSPML's "Low Load" case represented a reasonable planning case and that NSPML's "Base Load" case was, in reality, a "High Load" case. Second, Synapse reported its results for both a Planning Period of 25 years and for an indefinite Study Period. It noted that when "end effects" are considered in the way that NSPML modeled them, the ML Project is seen to be less costly than the modeled alternatives in all cases (i.e., over the "Study Period", which extends out infinitely). Synapse did not attempt to change either the modeled Planning Period (25 years) or the way in which "end effects" are calculated.

[105] The Board has reached the following conclusions about load and the issue of "end effects".

[106] On balance, the Board believes that NSPML's "Low Load" forecast, which most closely aligns with NSPI's current load forecast, is a more realistic scenario than NSPML's "Base Load" forecast. The Board accepts the evidence of Synapse, Levitan and Resource Insight that NSPML's "Base Load" forecast is more in the nature of a high load forecast. However, as was pointed out, a number of factors could impact load in a

way which could cause it to be higher. It is prudent for NSPI to have flexibility in their load forecasts.

[107] For example, NSPML's energy efficiency assumptions anticipate a 3.5 TWh reduction from current levels due to DSM. As an ever more aggressive DSM program is implemented by Efficiency Nova Scotia, projected energy savings are going to be more difficult to achieve. The DSM assumptions used by Synapse and some Intervenors would adopt a high DSM target, perhaps the most aggressive in Canada.

[108] In addition, while NSPI does not have to plan capacity for the load of the Port Hawkesbury Paper mill, it does have to be in a position to supply energy when needed. The fate of that mill, at the end of the current load retention rate, is unknown.

[109] What is known is that today's load forecast will not be correct in 10 or 20 years' time as unknown events will intervene. The Board needs to be satisfied that the ML Project was tested over a reasonable range of load assumptions. The evidence of both NSPML and Synapse provide us that information.

[110] Likewise, the Board also considered the evidence of NSPML and Synapse in reviewing the Strategist runs for the 25 year Planning Period versus the indefinite Study Period. The Board noted that Synapse and Levitan referred to a 26 year Planning Period, while NSPML used 25 years. The Board refers to it in this Decision as a 25 year period, but for purposes of analysis the Board made no distinction. While the Board is mindful that NSPI has used the Study Period model in its capital work order applications, the treatment of "end effects" in the present matter introduces a bias against alternative resource options because of the differences in the useful life of those resource technologies. For example, wind technology has a life of about 20 years, but

the re-commissioning of that technology for a further 20 years may be less expensive than other alternatives. Also, as noted later in this Decision, Levitan stated that the NPV results for the 25 year Planning Period should be considered more credible than the results for the Study Period because NSPML ignored technological progress in wind generation facilities. In the circumstances, the Board accepts the evidence of Synapse and Levitan and places greater weight on the Strategist results over the 25 year Planning Period.

[111] Synapse's other adjustments included: 1) reducing or eliminating the wind curtailment resulting in a higher effective capacity factor for this energy resource; 2) reducing the MW level of new wind to account for the increased capacity factor; 3) eliminating energy storage; 4) eliminating the 2030 and 2035 250 MW combined cycle installations and re-optimizing the dispatch for CO_2 constraints; 5) applying a one percent per year real cost decline for new wind resources; and 6) lowering the cost allocation for transmission capital investment.

[112] As a result of Synapse's Strategist analysis, it identified two runs which performed better on an NPV basis than the ML Project option. Moreover, three other Indigenous Wind runs, as well as a Hybrid option, produced NPV results which were within 0.5% of the NPV for the ML Project.

[113] Synapse's NPV results are summarized in the following table which is abstracted from Undertaking U-41:

Alternative	Description	Present Value, Planning Period, $2015, '000	Delta from ML, $2015 ('000) (+ means alternative is more expensive than Link), Planning Period	Planning period % Delta from Link (+ means alternative is more expensive than Link)	Present Value, Study Period, $2015, '000	Delta from ML (+ means alternative is more expensive than Link), Study Period
Strategist Runs – Low Load						
Maritime Link – Low Load	NSPML benchmark – ML, Low Load	8,942,252			12,087,122	
Indigenous Wind – Low Load	NSPML benchmark – IW, Low Load	9,264,205	321,953	3.6%	13,243,582	1,156,460
Wind 3a REVISED	35% CF wind (reduce/eliminate curtailment), reduced MW quantity of new wind to account for CF	9,198,524	256,272	2.9%	13,143,634	1,056,512
Wind 3b REVISED	Same as 3a, plus eliminate energy storage	9,063,657	121,405	1.4%	12,956,534	869,412
Wind 3c	Same as Wind 3b, plus elimination of 2030 and 2035 CC installation, re-optimize dispatch for CO2 constraint	8,983,131	40,879	0.5%	13,284,191	1,197,069
Wind 3e	Same as Wind 3c, plus 1%/yr real cost decline for wind	8,967,430	25,178	0.3%	13,259,868	1,172,746
Wind 3f	Same as 3e, plus lower cost allocation for transmission capital investment – no cost allocation for tie reinforcement, only $28 million for intra-NS buildout, 100 MW	8,788,815	(153,437)	-1.7%	13,012,076	924,954
Wind 3g	Same as Wind 3e, plus 36% CF performance for 2019 new wind (NOTE: includes full transmission investment/cost allocation)	8,956,783	14,531	0.2%	13,243,374	1,156,252
Wind 3h	Same as Wind 3g, plus reduction in transmission investment/allocation.	8,778,168	(164,084)	-1.8%	12,995,582	908,460
Wind 6a	Same as Wind 3a, plus reduce wind amount to account for COMFIT as RES compliant	9,318,260	376,008	4.2%	13,356,702	1,269,580
Wind 6c	Same as wind 6a, plus remove energy storage and eliminate 2030 CC.	9,250,150	307,898	3.4%	13,244,076	1,156,954
Hybrid OI/Wind	Start with NSPML OI Low Load, modify thru-NB import transaction, add NS wind, reduce transmission capital, add CC unit for reserves/emissions (+353 GWh renewables from import+wind in 2020 to meet "net short". Exceed RES in later years as load declines) *200 GWh annual import across NB tie, no planning reserve contribution *50 MW new NS wind, 2019, 35% CF *$273 million Onslow - Salisbury 2nd 345 kV tie rev rqmt – instead of $737 million in OI case *150 MW CC addition, 2017 (to meet reserves and emissions) *same transaction per MWh pricing as OI low load	8,983,305	41,053	0.5%	12,445,927	358,805
Strategist Runs – Base Load						
Maritime Link – Base Load	NSPML benchmark – ML, Base Load	10,776,055			16,075,449	
Indigenous Wind – Base Load	NSPML benchmark – IW, Base Load	11,642,720	866,665	8.0%	18,182,112	2,106,663
Wind 5a	Adjust wind amount to account for COMFIT as RES compliant, no energy storage	11,565,386	789,331	7.3%	18,192,398	2,116,949
Wind 5b	Same as 5a, plus 1%/yr real cost decline for wind	11,544,338	768,283	7.1%	18,159,840	2,084,391

[114] As explained later in this Decision, the results for the Hybrid option were introduced during the hearing.

[115] Synapse concluded in its prefiled evidence that:

> Generally, our summary finding is that the Maritime Link project as proposed by NSPML as a contract supply arrangement for NSPI has not been demonstrated to be a definitive least-cost incremental supply resource for NSPI's system, in comparison to other options that seek to minimize the costs to obtain renewable energy needed to meet RES requirements (and not oversupply those requirements), over the planning period of 26 years. Those other options include either 1) indigenous wind alone; or 2) some combination of indigenous wind and imports across either the existing or a reinforced Nova Scotia/New Brunswick transmission interconnection.
>
> [Synapse, Exhibit M-49, p. 3]

[116] As noted earlier, Morrison Park was retained by Board Counsel to provide an opinion as to the fairness of the ML Project to ratepayers. Morrison Park considered the levelized unit electricity cost of the amount of power required to satisfy Nova Scotia's RES requirements for the foreseeable future.

[117] It concluded that the ML Project is fair, from a financial point of view, to Nova Scotia ratepayers.

[118] Morrison Park also considered the relative financial and other benefits to Emera, to Nalcor, and to Nova Scotia ratepayers, and found these financial and other benefits to be commensurate with the contributions being made and the risks being taken by the respective parties. Further, Morrison Park considered certain of the financial arrangements of the ML Project (including debt arrangements and the equity rate) and found no indication that these were commercially unreasonable.

[119] However, Morrison Park noted that Nova Scotia ratepayers are responsible for the risk of the physical completion of the Maritime Link, both in terms of the construction timeline and budgeting risk. It suggested that in such circumstances a

mechanism could be put in place to more fairly apportion the risk. This issue is canvassed by the Board in Section 6.9 of this Decision.

[120] Levitan stated that NSPML's comparative analysis was "over-simplistic, lacks robustness, and appears stacked to support the Applicant's desired outcome". It concluded:

> ...In our professional opinion, the engineering, economic, and financial evidence furnished by the Applicant is not sufficiently persuasive to justify committing Nova Scotia customers to a large, immediate, long-term, iron-clad financial obligation, one that will hinder, if not preclude, the Province's ability to add diverse renewable resources as well as other imports over time as required to meet the environmental objectives set forth in the Legislation.
>
> [Levitan, Exhibit M-45, p. 6]

[121] Among its findings, Levitan concluded that NSPML's forecasts for load, energy and fuel price were inconsistent and improperly formulated, too much weight was given to the "Base Load" scenario (and insufficient weight given to the "Low Load" scenario, which Levitan said was in effect a baseline scenario), and NSPML's analysis treated existing energy resources differently from new resources during the "end effects" period at the end of the Planning Period.

[122] On this latter point, Levitan stated:

> ...Recall that the model assumes that the new resources are replaced in kind at the end of their useful life, throughout the end effects period, but the Strategist model does *not* include any in-kind replacement of the existing units during the end effects period. By not including the capital and operating costs for the still-existing units or their replacement in-kind units during the end effects period, the end effects NPV is biased against an alternative that retires more capacity during the Planning Period. Expressed differently, the resource alternative that carries *more* still-existing units through the end effects period has a smaller replacement cost burden and hence its NPV is biased low. [Emphasis added in original]
>
> [Levitan, Exhibit M-45, p. 18]

[123] Finally, asserting that NSPML ignored any progress in wind generation technologies into the future, Levitan stated:

> Because technical progress is ignored, we believe that the NPV results over the [25 year] Planning Period should be considered more credible than the NPV results over the [longer] Study Period. ...
>
> [Levitan, Exhibit M-45, p. 21]

6.1.2 Other Import

[124] Based on the Board's review, the Other Import option suffers from one major shortfall. In the end, this option lacks a reasonably foreseeable source of imported energy.

[125] The underlying basis for this alternative is the availability of a long-term contractual relationship with Hydro Quebec for the supply of renewable energy. No Intervenor has suggested any other potential source of imported energy.

[126] In its Opening Statement, NSPML stated that, despite its efforts, there is no long-term, fixed price energy available from Hydro Quebec:

> We have been asked about discussions with Hydro Quebec and why we didn't go through a competitive bidding process and bring forward a long term competitive contract as an alternative to the Maritime Link.
>
> Emera and Nova Scotia Power have worked with Hydro Quebec for many decades. We met with them specifically to discuss and consider this alternative and simply put, there is no long-term, fixed price energy available from Hydro Quebec.
>
> [NSPML Opening Statement, Exhibit M-96, pp. 3-4]

[127] In cross-examination by the CA, Rick Janega, President of Emera Newfoundland and Labrador, outlined NSPI's past efforts to secure a long-term contractual supply of energy from Hydro Quebec, specifically discussions which occurred in April 2009:

> ... And at the time, we were aware of the abundance, as people have indicated, of energy from Hydro Quebec.
>
> We knew that we had transmission constraints in Quebec, and we also knew from doing or completing energy purchases from them every year, we would transact a couple of million dollars' worth of business with Hydro Quebec or we've had standing orders for energy purchases. We knew that we were not their target market overall, that they had interconnections into New England and New York.

> So prior to us meeting with Hydro Quebec, there were discussions at senior levels within HQ and Emera about how we may be able to participate together in looking at opportunities for a larger-scale import.
>
> This meeting actually was an attempt for us to essentially put together a large enough volume of energy to be of interest for Hydro Quebec, and Bangor Hydro and Nova Scotia Power actually participated together in that meeting, looking to see if we were able to find ways and means that we may be able to find a commercial arrangement.
>
> <u>Our objective heading into that meeting and into discussions with other suppliers of imported energy was it had to provide a long-term fixed price stable component as a minimum</u>. And our objective for that was to get away from a lot of what was occurring in Nova Scotia at the time, which was exposure to the volatility of the market.
>
> So heading into this session, we had -- <u>we had completed our thinking on what we were looking for. It was to support shutting off coal-fired generation, dealing with our emissions reductions, providing firm capacity and a renewable energy component.</u>
>
> So we headed to Hydro Quebec. We had meetings with them. It became very clear during the course of that that they had developments under way both on the generation or energy side and on their transmission interconnectivity to places like Ontario and the United States.
>
> <u>Nova Scotia was not a part of their target market at the time. And it became very clear through discussions that there was no interest in a long-term fixed price arrangement to sell energy, that their predominant mode of operation was to arbitrage energy to the highest value markets that they have existing interconnections with.</u>
>
> ...
>
> MR. MERRICK: So am I understanding correctly that you essentially had one round of discussions with Hydro Quebec of any substance?
>
> MR. JANEGA: No. I would say we had one very pointed discussion with them where they had indicated clearly to us there was no interest in a long-term fixed price supply arrangement.
>
> ...
>
> MR. MERRICK: And what volumes were you talking about at that time?
>
> MR. JANEGA: Well, we were open to a variety of volumes, but we wanted the minimum to be able shut down or displace a coal-fired generator [about 165 MW] but, you know, our traditional approach at that time would have been to look at if there was more or if we could see a path that we would be able to actually utilize the energy to curtail more emissions and meet our requirements, we would consider that as well. [Emphasis added]
>
> [Transcript, May 28, 2013, pp. 236-241]

[128] Mark Sidebottom, NSPI's Vice President, Generation and Delivery, also described his company's recent efforts (albeit after the ML Project had already been negotiated with Nalcor):

> I have personally met with Hydro Quebec [2013 Q1] along with our CEO and EVP and actually had a series of meetings and discussions, starting at the front end of this year. And they would describe again an interest to be indexed to the market, which is consistent with conversations they'd had in the past.

And they also recognized in the recent discussions I've had with them with the lack of a path through New Brunswick.

[Transcript, May 28, 2013, p. 275]

[129] In its Report, Morrison Park concluded that the Other Import option is not a reasonably viable alternative for consideration:

It is also apparent, however, that what the Applicant has called the Import Option is not actionable at this time. There is no commercial agreement in place with an alternative provider, nor have there been any discussions about the terms and conditions of such an import solution.

The fundamental feature of the Other Import option is that the imports would satisfy the need for renewable energy, in the same fashion that building renewable energy generation facilities in Nova Scotia would. ...

The difficulty is that there is no liquid commodity market for "renewable energy" in Northeastern North America. There are many markets for electricity, but these do not satisfy the Nova Scotia requirements for renewable energy. Renewable energy, up until today, is typically purchased through direct bilateral contracts between buyers and sellers. Often, these contracts are agreed to after competitive requests for proposals ("RFPs"), which are a means for buyers to get the lowest price possible for what they are buying, *in the absence of an open, liquid and competitive market.* [Emphasis in original] This presumes that there are multiple sellers who would actually qualify for and compete to satisfy the terms of an RFP. In the absence of a liquid market, and in the absence of a group of competitive suppliers who would be expected to participate in an RFP, there is little basis upon which to [base] assumptions about the price of a bilateral renewable energy contract.

Given that Nova Scotia's primary electricity requirement is for renewable energy, and this requirement is large (somewhere between 500 and 1000 GWh per year, according to the projections provided by the Applicant), and it would require substantial upgrade to the existing transmission system, it is not reasonable to simply assume that it could be commercially achieved, and especially at a price that would be cheaper than Nova Scotia's domestic option.

...

The only alternative would be for Nova Scotia to build its transmission improvements without first negotiating a purchase of renewable energy, and only then seek to buy power through an RFP or similar competitive process. Again assuming there were several potential suppliers, then Nova Scotia could hope for some competitive market discipline to hold prices down. However, given the time constraints to meet Nova Scotia's 2020 renewable energy requirements, it does not appear that this option is open.

From a commercial perspective, the Other Import option effectively does not exist as an independent economic possibility distinct from the Status Quo. Analysis of its features is pointless, ... [Emphasis added]

[Morrison Park, Exhibit M-46, pp. 44-45]

[130] Moreover, another important element of the Other Import alternative is that it would require significant upgrades to the NS/NB transmission interconnection, as well

as possible upgrades at the Quebec/NB interconnection and other transmission upgrades within New Brunswick.

[131] As noted earlier in this Decision, NSPML retained WKM to review the transmission issues. WKM was asked to determine the cost of adding transmission infrastructure through the NS/NB corridor so that NSPI could have a firm 165 MW transmission path and the opportunity to purchase additional energy up to 500 MW (less the firm portion), effectively providing similar capacity as the Maritime Link.

[132] WKM's analysis showed that the total estimated cost of the upgrades to develop a new 500 MW transmission interconnection for firm supply from Hydro Quebec to Nova Scotia through neighboring jurisdictions would be $1.3 billion. Of this total amount, WKM estimated that NS would be required to pay a minimum of $905 million, according to FERC principles.

[133] NSPML summarized WKM's evidence in its Reply Evidence:

> As WKM explains, in order to import even 150-200 MW through NB several transmission upgrades are required. To address congestion around the Moncton area an additional 345 kV line needs to be constructed between Coleson Cove and Salisbury [NB]. Additional voltage support is also required. Supported by estimates from the Atlantic Energy Gateway Study (AEG) undertaken by the four Atlantic utilities and the federal government, WKM estimated the cost of these upgrades to be $287 million. Additionally, a second tie line between NS and NB is required so that firm NS Power customers are not subjected to the risk of Under Frequency Load Shedding on a regular basis. WKM estimates this cost at $224 million. The costs of these upgrades alone – quite apart from addressing any issues to get the energy over the Quebec/NB interface - exceed $500 million. Addition of a $437.5 million cost to enable 165 MW firm supply from Quebec increases the cost of a 150 to 200 MW supply option from Quebec to a total of about $940 million NPV.
>
> [NSPML Reply Evidence, Exhibit M-83, p. 34]

[134] WKM's principal, Mr. Marshall, is New Brunswick's former System Operator. He has an intimate knowledge of the Maritimes' transmission infrastructure and system requirements. The Board found his evidence to be very helpful and it accepts his evidence.

6.1.2.1 Findings

[135] The extent of required transmission upgrades was the topic of much evidence at the hearing. However, irrespective of which transmission upgrades may be required, the Board considers the lack of any reasonable prospect of a long-term contractual arrangement with Hydro Quebec proves fatal to this option. The Board accepts the evidence of Morrison Park on this point.

[136] Moreover, the Board notes that the NPV analysis conducted by Synapse and Levitan did not produce a least-cost solution for any Other Import scenario, except if Market-priced Energy is not available from Nalcor.

[137] Based on the evidence, the Board finds that the Other Import option is not a lower long-term cost alternative to the ML Project.

6.1.3 Indigenous Wind

[138] While the Indigenous Wind option is a domestic solution to Nova Scotia's future renewable energy needs, it does present significant challenges in terms of integrating the wind capacity on NSPI's bulk power system.

[139] These challenges were described on several occasions throughout the hearing by the NSPML witness panel, particularly Mr. Sidebottom and Mike Sampson, NSPI's Director of Planning and Performance.

[140] Mr. Sampson noted that the challenge is not limited to only integrating an incremental amount of wind such as 250 MW. He noted that the challenge also lies in the integration of the entire wind portfolio, which would represent a relatively high percentage of NSPI's bulk power system as compared to other jurisdictions in the world. In cross-examination by Tom Levy of CanWEA, Mr. Sampson testified:

> ... I think it's important to understand what we're talking about here with this -- with these two cases, both the low and the high [load cases]. <u>We're not talking about integrating the first 250 or the first 575 megawatts of wind on the power system. We have five -- we will have 535 -- 535 megawatts upon the completion of the 100 megawatt COMFIT program.</u>
>
> <u>And so this is an incremental 250 megawatts on a loosely connected power system on the edge of the power grid.</u> It is predominantly coal-fired, has those coal-fired units being pushed down into operating ranges they were not necessarily originally designed for. And I don't know if you could point to other jurisdictions that are -- that you would -- that you could take direction from in terms of how far these scenarios go.
>
> And I would suggest that these -- these are very conservative, in my opinion. I think we could grossly exceed these midpoint expenditures, and I think we were trying to be fair, but reflect -- in the White paper we were trying to provide information to the Board on what we thought would be necessary to stabilize our power system under these considerations. And these are -- these are extreme considerations based on what the industry knows today. [Emphasis added]
>
> [Transcript, May 29, 2013, pp. 625-627]

[141] In his testimony, Mr. Sampson added that increasing the level of wind penetration on the grid raises a number of operational challenges for the bulk power system, including the requirement to curtail wind energy:

> ... I stand behind those curtailment figures because I think with what we're talking about here in terms of the quantity of wind on this power system, I mean I know you cited Hawaii and Ireland as thinking about it or considering it. But, you know, in the case of Hawaii, it's an island in the middle of the Pacific with no options and a $.42 or a $.37 kilowatt hour. And I think we have a better option than to consider this type of measure. And so I think that the industry does not understand these levels of wind penetration well enough to argue about whether wind curtailment could be minimized.
>
> When I went to the control centre a number of years ago I came from a generation background and I thought I understood the system operation well. As a generator in hydro we responded to peak system operation, we responded to ramping and black start, many things that I thought were the system. But it's quite an eye opener when you start -- when you get involved with the operation of a bulk power system. And there are aspects -- you know, this discussion is really coming down to energy.
>
> And there are many other attributes that a power system needs besides energy. And in the Maritime Link we have found a source of renewable energy that brings many of the necessary and vital other elements to the power system, that being capacity and some regulation and load-following capability.
>
> Not to mention the ability to schedule surplus purchases in a manner that can make up for wind forecast errors or other such. So I think, you know, we -- yeah, I guess just to finish off we -- you know, I believe those are sensible given the extreme level that we're talking about here in terms of percentages of wind relative to average load and minimum load.
>
> [Transcript, May 29, 2013, pp. 632-634]

[142] Mr. Sidebottom also addressed the practical implications of dealing with a large amount of wind on the system:

> ...One of the significant things that happens is the ramp rate or ramp down in Nova Scotia can be significantly exaggerated with the integration of wind. And we would see several hundreds of incremental megawatts of ramping required in this province beyond what we have today, analyzing the potential wind we have today. So we have a very -- very good idea of what's on the ground today with our 315-odd megawatts.
>
> It interestingly enough acts more like a single generator because, of course, diversity was one of the things we first wanted to explore. You know, was one wind turbine going to run when another one wasn't? In fact, we found that Nova Scotia just has a bit of a time difference. And what you find is it ramps up and then it ramps down, and it acts very much like one great big generator.
>
> And as you start to do that, you realize you have to do something completely different in Nova Scotia to integrate that, because even though we've invested a lot in forecasting our wind, we can see out as far as four days. And that's with a reasonable expectation. We have a very good idea of the next hour, and a reasonable idea of the next day.
>
> And what that means is that 900 megawatt generator may or may not be there four days from now. And we have to ensure that Nova Scotia customers are served reliably through that characteristic. That is the integration of wind in the system in Nova Scotia. And that's why we feel that 100 to 200 megawatt pump storage unit shifting some of this load is not at all unreasonable, because we've got this 900 megawatt or 1,000 megawatt undulating generation source through the province, and with very little ability to forecast out more than four days.
>
> ...
>
> Now, to date, we've been able to handle it with the resources we have. Tomorrow, we're going to have less coal resources and we'll be retiring those, and we'll end up having to compensate with the rest of the resources out there. We have to be ready for the morning peak and we have to be ready for four days from now.
>
> [Transcript, May 29, 2013, pp. 627-629]

[143] As noted by counsel for NSDOE, Morrison Park stated that the risks of significant wind integration costs cannot be understated:

> ***The Indigenous Wind option on the other hand is scalable, and can be more accurately sized to meet renewable requirements. However, it would appear that this option suffers from diseconomies of scale, since the larger the build of the province's wind fleet, the more likely and more severe the impact on the transmission grid that must be managed.*** [Emphasis added in original]
>
> [Morrison Park, Exhibit M-46, p. 50]

[144] Morrison Park concluded that risk aversion is a critical factor to be considered in the analysis of the alternatives:

> ...The Indigenous Wind option appears to have a lower certain cost, but scale effects are perverse, and if more facilities have to be erected the increasing impact on the electricity system as a whole will require additional investments potentially leading to a much higher cost. Risk aversion is a critical deciding factor.
>
> [Morrison Park, Exhibit M-46, p. 62]

6.1.3.1 Findings

[145] Based on its review of the evidence, the Board is prepared to accept the evidence of NSPML and NSPI, as well as Morrison Park, with respect to the challenges posed by the integration of wind on Nova Scotia's bulk energy system. The Board accepts their evidence that integration costs would increase as incremental levels of wind were placed on the system (ranging from $48/MWh to $61/MWh). Further, operational challenges would present themselves with increasing levels of wind.

[146] Nevertheless, unlike the Other Import alternative, the Board does consider the Indigenous Wind option to remain as a viable alternative for consideration in this matter. This would mean, however, that increased costs or other measures as noted by NSPML might be required to implement such an option.

6.1.4 Hybrid Option

[147] NSPML did not model a Hybrid option as part of its analysis. Such a model would have combined more modest amounts of energy from different sources such as Indigenous Wind, Imported Energy over the NS/NB interconnection, and combined cycle generation, among other sources.

[148] In the Board's view, NSPML has not satisfactorily explained why a Hybrid scenario was never pursued (see CA/SBA IR-70 and IR-354).

[149] Given the tight timeline afforded to the Board and to the parties for this proceeding under the *ML Regulations*, Synapse attempted, but was unable, to successfully complete a Strategist run for a Hybrid option before the filing deadline of its

prefiled evidence. Strategist modeling is a complex process which can take up to two weeks or more to execute a successful run. On occasion, the computer modeling can abort a run because of the input assumptions. However, in advance of the hearing, Synapse was able to successfully complete a Hybrid run, the results of which were requested to be filed at the hearing as Undertaking U-41.

[150] In Undertaking U-41, the NPV of the Hybrid option was calculated to be $41 million more expensive than the ML Project (a difference of only 0.5%).

[151] In light of the very modest levels of incremental wind and imported energy used in the Hybrid option, the Board considers that the concerns outlined with the Indigenous Wind and Other Import options could be mitigated under this scenario and these sources of energy could be better implemented into Nova Scotia's bulk energy system.

6.1.4.1 Findings

[152] The Board sees one benefit of the Hybrid option as representing a more modest or conservative approach to adding incremental sources of energy on Nova Scotia's electricity grid. While the ML Project still performed better on an NPV basis, it performed only slightly better.

6.1.5 ML Project

[153] NSPML asserted that the ML Project has been demonstrated to be the lowest long-term cost alternative for electricity for ratepayers because it provides a "robust" option for the province's future energy needs across a broad range of reasonable assumptions:

> ...In the face of uncertainty, NSPML and NS Power understand that there will continue to be an obligation to serve customers when and where the load is needed, and that the obligation to serve must be met in compliance with all legal requirements.

> It is not unusual for the Board to make decisions about utility applications in the face of uncertainty about the future. ... In order to ensure that the decision can be made with "no regrets", the Board will look for evidence and analysis that demonstrates the chosen alternative is "robust" under a variety of potential future scenarios. Plan robustness is the ability of a plan to withstand realistic potential changes to key assumptions. A plan does not have to be the lowest cost under every potential or conceivable scenario in order to be found to be robust. An alternative will be found to be a robust solution when it is tested under a variety of scenarios and remains the low cost option under a broad range of reasonable assumptions. ...
>
> In the face of uncertainty, it is foolhardy to make plans that are based on hope, such as the hope that the cost of fuel or capital cost of wind farms will decrease, or to hope for negative load growth due to aggressive or optimistic DSM programs. ... In contrast, the utility and the Board require some measure of certainty, and are required to take necessary steps to ensure a safe and reliable power supply long into the future. The consequences of failing to plan conservatively and to adopt robust solutions, or of failing to meet the obligations to customers, are serious for the utility and for customers, and we are confident the importance of these consequences is well understood by the Board. [Emphasis added]
>
> [NSPML Reply Evidence, Exhibit M-83, pp. 6-7]

[154] In the Board's opinion, the ML Project provides a reasonable alternative to Nova Scotia's future renewable energy needs. This alternative is supported, at least in part, by a contractual relationship with a stable counterparty which has the capacity to meet a portion of Nova Scotia's energy needs for many years.

[155] As noted by Morrison Park, the ML Project is supported by:

> ... a real, fully negotiated commercial agreement, which is actionable now.
>
> [Morrison Park, Exhibit M-46, p. 44]

[156] Except with respect to the issue of Market-priced Energy, the Board is satisfied that the range of sensitivities tested by NSPML in its Strategist modeling represents a prudent approach to evaluating energy alternatives for the province and its ratepayers. The Board is generally satisfied with the reasonableness of most of the various assumptions made by NSPML in the composition of the ML Project alternative (except, as noted earlier in this Decision, the concerns referred to by Synapse, Levitan and other parties about load and the Study Period used in the analysis).

[157] The ML Project attracted the support of the Government of Canada in the form of the FLG. As described later in this Decision, the backing of the FLG is expected to reduce the cost of the ML Project by more than $250 million over the term of the ML Project (more than $100 million on an NPV basis). The Board accepts NSPML's evidence that the Other Import and Indigenous Wind options would most likely not receive a similar FLG.

[158] Further, the Board is mindful that the presence of the Maritime Link could potentially benefit NSPI and Nova Scotia ratepayers in other ways.

[159] One of the important potential benefits of the ML Project is that it could provide access to Market-priced Energy. In fact, it is the access to this energy which causes the ML Project (assuming the Market-priced Energy is available) to be the lowest long-term cost alternative for electricity for Nova Scotian ratepayers.

[160] NSPML noted in its Application, and its witnesses highlighted during the hearing, that the Maritime Link offers Nova Scotia an "historic opportunity" by greatly strengthening the province's connection to the North American electricity grid, thus improving access to electricity markets. Until now, Nova Scotia was obligated to be self-sufficient in electricity with only limited ability to import electricity from the North American grid over the intertie to New Brunswick. The Maritime Link positions Nova Scotia in the middle of electricity markets, and no longer at the end of transmission lines with limited market access.

[161] In the Board's view, the Maritime Link allows Nova Scotia to add an important tool to its portfolio of assets to access Market-priced Energy, when it is economical to do so, and in amounts that are required.

[162] NSPML stated that the Maritime Link creates a "new regional electricity loop that gives access to competitive energy markets". Nova Scotia will be connected to NL and consequently to the North American electricity grid via the LTA and Quebec. The existing path through NB to New England completes the loop.

[163] The Board observes that the presence of the Maritime Link could continue to benefit Nova Scotia even after the expiration of the 35 year term of the Commercial Agreements, because Nova Scotia will still be positioned to access competitive energy markets.

[164] The second, and separate, interconnection also benefits Nova Scotia's bulk energy system, and its ratepayers, by providing increased reliability. As noted by Board Counsel consultant M. Dale McMaster, formerly President and CEO of the Alberta Independent System Operator:

> It is a common understanding in the electric utility industry that interties enhance system reliability provided that they are properly planned and integrated. The benefits come through such things as reserve sharing, increased ability to withstand system contingencies and in the event of a major interruption, assistance in system restoration.
>
> [McMaster, Exhibit M-47, p. 4]

[165] Mr. McMaster indicated that the Maritime Link will provide "the added benefit of geographic diversity over a reinforced/new intertie with NB".

[166] Consistent with NSPML's assertions about the new regional electricity loop, Mr. McMaster also confirmed that:

> The [Maritime Link] would improve Nova Scotia's market position as it would be in the enviable position of sitting between two sources of supply – the traditional market on the NS-NB intertie and the new source of supply in Newfoundland and Labrador.
>
> [McMaster, Exhibit M-47, p. 6]

[167] The Board accepts Mr. McMaster's evidence and insight on these points.

[168] As noted by NSPML in its Application, the ML Project is, in effect, a response to the Renewable Electricity Plan, which is intended to wean Nova Scotia off of fossil fuels, with their high emissions and volatile prices. If fossil fuels continue their price volatility into the future, then the Maritime Link provides access to a clean, reliable source of energy at market based prices, as an alternative to coal and natural gas.

[169] However, in the end, the test under the *ML Regulations* is not a qualitative assessment of the various benefits or risks of the ML Project. Rather, the test the Board must apply is a quantitative measurement of the Application.

6.1.5.1 Findings

[170] Taking into account all of the evidence, the Board finds, on the balance of probabilities, that the ML Project (with the Market-priced Energy factored in) represents the lowest long-term cost alternative for electricity for ratepayers in Nova Scotia. In the absence of Market-priced Energy, the ML Project is not the lowest long-term cost alternative for electricity for ratepayers in Nova Scotia.

[171] While the Board finds that the ML Project is the lowest long-term cost alternative, it is not on an overwhelming basis. Based on the evidence presented by Synapse, which the Board accepts, there are various scenarios, within a range of reasonable assumptions, that perform almost on an equivalent basis, or even better in a few cases, than the ML Project. On this point, the Board refers to Synapse's Strategist runs of the Indigenous Wind "Low Load" scenario, as well as the Hybrid option formulated in Undertaking U-41.

[172] The Board does not interpret the test in the *ML Regulations* in a way whereby the ML Project fails because one or two scenarios indicate it could fail.

Instead, over a broad range of assumptions, the ML Project passes the test because on a balance of probabilities it remained the lowest long-term cost alternative if Market-priced Energy is factored in.

[173] The Board concludes that over the broadest range of Strategist runs for the ML Project it is slightly more robust than the various other alternative runs conducted by Synapse. On this basis, the ML Project does edge out other alternatives and is deserving of approval under s. 5(1) of the *ML Regulations*.

6.1.6 Market-priced Energy

[174] Notwithstanding the Board's finding that the ML Project provides a reasonable alternative to Nova Scotia's future energy needs and the Board's general satisfaction with the reasonableness of most of NSPML's various assumptions in the composition of the ML Project alternative, the Board remains very concerned with the availability of Market-priced Energy under the ML Project, as presently proposed.

[175] The price and availability of Market-priced Energy, including Nalcor Surplus Energy specifically, was the topic of much evidence in this proceeding.

[176] Many Intervenors identified this issue as a significant risk of the ML Project. In their written submissions, the CA, SBA, Industrial Group, CanWEA, LPRA, the Liberal Caucus and PC Caucus all identified the uncertainty surrounding Market-priced Energy as their primary concern.

[177] In its Closing Submission, the SBA stated:

> It is clear from the evidence submitted and the testimony of representatives of the Applicant, there is no guarantee of the quantity or price for surplus energy to be acquired by the Applicant through the Maritime Link and their evidence is clear, without a substantial price lower than the Nova Scotia block price for surplus energy, this would not be a good deal for the rate payers of Nova Scotia. It is further submitted, for this project to be the least cost alternative there must be a guarantee of price and quantity for that energy to be ascertained to determine whether this is the least cost alternative.

...

> The modeling done by NSPML to make it's case that the ML is the lowest cost long-term alternative relies on a significant amount of low priced surplus energy being available from Nalcor via the ML to "average down" the high price of block energy as shown in Fig. 4-4, of [Exhibit M-2]. However, as the evidence clearly indicates, there is no obligation on Nalcor to provide *any* amount of surplus energy to NS, there is no option for such surplus energy, and there is no right of first refusal for such surplus energy. In short, the modeling done by NSPML, as shown in Fig. 4-4, is based on pure hope or speculation when it comes to the availability (not to mention, cost) of surplus energy. [Emphasis in original]
>
> [SBA Closing Submission, pp. 7-8]

[178] According to NSMPL, a contractual arrangement with Nalcor for Market-priced Energy is not necessary, since such energy will be readily available if, and when, NSPI needs such energy. In its Opening Statement, it explained its rationale for this assertion:

> <u>The Maritime Link agreements that we subsequently negotiated with Nalcor and have included as part of our application do not include a contract for the surplus energy beyond the Nova Scotia Block. But the fact is we don't need one</u>. When surplus energy, beyond Nalcor's domestic needs, is flowing across the province and through New Brunswick to the New England market, we can purchase energy from New Brunswick or Hydro Quebec or Nalcor. That is because we will be in a position to take the energy flowing through Nova Scotia even if we purchase energy from a counter party other than Nalcor. Being located in the middle of the energy market instead of at the end of it is a clear benefit of the Maritime Link Project.
>
> We've also heard questions about whether Nalcor will have enough energy available to flow any surplus beyond the Nova Scotia Block to market. We are confident that the evidence clearly shows that Nalcor will indeed flow surplus energy. I note that the Board's consultants, Morrison Park, also reach the same conclusion. Nalcor is paying for 80% of the Maritime Link and as Mr. Martin, Chief Executive Officer of Nalcor, indicated in his recent letter filed with our reply evidence; they are doing that because they intend to use it. [Emphasis added]
>
> [NSPML Opening Statement, Exhibit M-96, p. 2]

[179] In his testimony, Mr. Janega stated that it was not necessary to conclude a contractual arrangement with Nalcor for the Market-priced Energy:

> Mr. Merrick, if your question is whether they [Nalcor] have stated the words that they would sell to us, they have. In conversations that we've had with their energy marketing people as a part of negotiating the commercial agreements, we had direct discussions about access to surplus energy on multiple occasions.
>
> When Nova Scotia Power was negotiating their portions of the energy and capacity agreement, it was almost a weekly discussion, and they have said the words -- though if

> it's a matter of, you know, putting in writing that they understand the market drivers and the market dynamics, we don't feel that that was necessary in a letter.
>
> We've presented market-based pricing. They are a supplier selling into that exact same market. They would look at the same pricing structure, and the only difference would be are they going to give up the potential value of the netback that they could save? Are they going to give that away to sell further down the line, or are they going to take that and put part of it in their pocket and we put part of it in Nova Scotia customers' pockets?
>
> [Nalcor's] not going to state that in a letter, but we have had that discussion directly with Nalcor, with their energy people. They understand it. We understand the market. The people in Nova Scotia Power that will be negotiating those supply arrangements will be able to achieve opportunities that no other alternative can provide for Nova Scotians.
>
> ...
>
> ... The only other place that we can easily interconnect to is New Brunswick to tap into the same existing resources for -- of renewable energy, and this is not that case.
>
> This is a new source of energy going to the same market. There will be surplus energy, and if it's not that energy, this energy is going to displace other energy in the marketplace which we can buy that. Nova Scotians can benefit from that.
>
> If the energy flows through Nova Scotia, for every megawatt leaving the province, notionally we should be able to bring one back in from the same marketplace that we've priced at market prices. It doesn't have to be Nalcor Energy. We're somewhat fixated on them supplying it. It really doesn't matter who it is.
>
> As long as it is built and we are interconnected, one of two things will happen. It will flow by our doorstep and we'll be buying it because it's economically advantageous to both of us, or it will go to market creating what in the transmission world is a netting effect. That energy will stay in Nova Scotia if it's destined for New England, and then New England energy that was going to be produced that it would displace is staying in that market. Nothing flows. The system's optimized.
>
> But it all transacts based on the very same market-based pricing that we've modeled in our alternatives. ...
>
> [Transcript, May 28, 2013, pp. 193-196]

[180] Nevertheless, as noted above in its Opening Statement, in order to ease the concerns of Intervenors with respect to the availability of Nalcor Surplus Energy, NSPML filed, as part of its Reply Evidence, a letter dated May 16, 2013, from E.J. (Ed) Martin, Nalcor's President and CEO, to Chris Huskilson, President and CEO of Emera. In addition to outlining Newfoundland and Labrador's intention to develop a variety of renewable sources of energy, including the Lower Churchill, the letter stated, in part:

> With the decision to sanction all components of the Lower Churchill Project now behind us, I am only too pleased to share our vision for working with Emera to export energy over the Maritime Link to assist you in your proceedings with the Nova Scotia Utility and Review Board.

By way of background, Nalcor Energy's roots and mandate are founded in the 2007 Energy Plan: *Focusing Our Energy*. ... It also identifies the Government's willingness to export energy that is surplus to our Province's needs.

...

As has been stated many times, the Lower Churchill is being developed first for the benefit of Newfoundland and Labrador. It will meet our Province's energy needs for many generations to come by providing clean, renewable energy at stable prices. It will provide energy to foster economic development and create new opportunities in our Province. Indeed, we are already seeing opportunities to support mining initiatives in Labrador and we look forward to supporting such initiatives whenever the business case exists to do so.

We also recognize there are business opportunities outside of Newfoundland and Labrador associated with the development of the Lower Churchill as well as the Province's entire energy warehouse. That is why we are so excited and pleased that Emera has committed to develop the Maritime Link between the Island of Newfoundland and Nova Scotia. In accordance with the vision laid out in the 2007 Energy Plan, Nalcor is working with Emera to export power over the Maritime Link that is surplus to our domestic needs, whether that energy is from Muskrat Falls, Gull Island which has already been released from Environmental Assessment, small scale hydroelectric developments or wind. In this regard we are well aligned in our long term vision and business objectives.

As I understand it, your analysis to the UARB involves Emera purchasing energy from the market, with the purchase being enabled by the Maritime Link. In addition to the Nova Scotia Block, there is an assumption that over the 35 years that NSPML owns the Maritime Link, electricity is flowing across the Maritime Link into Nova Scotia. Given Nalcor's mandate as well as our current load forecasts, we consider this to be a reasonable assumption. The Maritime Link opens new avenues for export sales that will generate additional long term revenues for our Province, and we intend to work with you to keep it at its maximum capability for the export of clean, renewable energy over its entire life by identifying and pursuing market opportunities which provide an appropriate return. And I assure you, we are indeed open to business for the export of energy that provides solid economic returns to the Province. Nalcor looks forward to a long and mutually beneficial relationship with Emera and Nova Scotia as well as Atlantic Canada. [Emphasis added]

[NSPML Reply Evidence, Exhibit M-83, Appendix D, pp. 1-2]

[181] Notwithstanding the above, the NSPML witness panel explained in its testimony that it attempted, in fact, to extract contractual concessions from Nalcor for the future supply of Market-priced Energy. In cross-examination by the CA, Mr. Janega testified:

...There are actually two levels of engagement through this. All through the negotiations of the commercial arrangements and then in the final ECA agreements in which Nova Scotia Power was a direct negotiating party, in the instances leading up to the ECA, we had sought to acquire additional volumes of surplus energy and look to gain rights to that. And as have indicated, the best, at the time we could get was an acknowledgement of the fact that that energy is going to market and they acknowledge the preferential position

> Nova Scotia is in and, in their words, we should be doing business to sell surplus energy in the future, to us.
>
> [Transcript, May 28, 2013, pp. 201-202]

[182] The Board considers it instructive at this point to review the evidence respecting the projected availability of Market-priced Energy from Nalcor in the future.

[183] In its Report, Morrison Park stated that the availability of Market-priced Energy from Newfoundland and Labrador is an issue of "substantial uncertainty".

[184] The starting point for this review begins with the 824 MW Muskrat Falls Generation facility, which is projected to produce almost 5 TWh of energy.

[185] The first 2 TWh (or 40%) produced from Muskrat Falls is intended by Nalcor to replace production from the Holyrood Thermal Generating Station, which will be put into stand-by operation in 2017, when Muskrat Falls and the LIL are in service: see NSUARB IR-64, Exhibit M-11. Holyrood currently serves an important part of NL's existing load.

[186] In accordance with the 20 for 20 Principle under the Nalcor Transactions, 20% of Muskrat Falls energy (about 1 TWh) goes to Nova Scotia as the NS Block.

[187] The remaining 40% of the energy produced from Muskrat Falls (or about 2 TWh) comprises Nalcor Surplus Energy under the Commercial Agreements, which make up the Nalcor Transactions. NSPML stated that this could be available to Nova Scotia. However, evidence presented by the Intervenors and Board Counsel witnesses suggested that much, if not all, of this remaining 2 TWh may be committed to other uses for much of the 35 year term of the ML Project.

[188] Morrison Park stated in its Report:

> According to projections filed by Nalcor in regulatory hearings before the Newfoundland Public Utilities Board, load in Newfoundland is expected to grow over time, and consume a progressively larger portion of the available supply from Muskrat Falls. ...

> ...[Muskrat Falls] by itself will not be able to support this projected Newfoundland load in the future (bearing in mind the extreme uncertainty of projections that stretch out decades). ... If those [NS Block] commitments are added it should be obvious that "surplus" power from [Muskrat Falls] will be limited in the much nearer, and perhaps more predictable future.
>
> [Morrison Park, Exhibit M-46, pp. 30-31]

[189] Indeed, in response to an Information Request from Board staff, NSPML did not challenge a statement contained on a website sponsored by the Government of Newfoundland and Labrador that claimed NL is "projected to need 80% of Muskrat Falls power by 2036, or even earlier as additional industrial growth occurs in the province." Instead, NSPML responded by referring the Board to other potential sources of energy from Nalcor:

> Nalcor has available the Surplus Energy from the Muskrat Falls project, which is 40 percent of the 4.93 TWh annual production, which is approximately 2TWh. In addition, Nalcor has available 300 MW of recall energy from the Upper Churchill, which it will now have access to market through existing routes and the Maritime Link. In 2041, the Upper Churchill reverts to ownership of Newfoundland and Labrador.
>
> [Exhibit M-11, NSUARB IR-65]

[190] Morrison Park noted, in fact, that Nalcor has available to it a further 525 MW of power from Churchill Falls in the form of the "Twin Falls" and "Recall Block" arrangements. However, the evidence suggested that even the Recall and Twin Falls Energy is in demand:

> The Recall Block of power – 300 MW at a maximum 90% load factor – was a term of the original Churchill Falls contract with Hydro Quebec, and lasts until 2041. The Twin Falls block is 225 MW at a maximum 90% load factor, fully subscribed and sold to mining concerns in Western Labrador. When the contract expires in 2014, the block will be made available to Nalcor at "market prices", presumably to be resold to the same customers. Together, the two blocks of power amount to approximately 4.2 TWh per year.
>
> [Morrison Park, Exhibit M-46, Footnote 10, p. 31]

[191] Nalcor also sells a significant portion of the Churchill Falls Recall Block to New York:

> ...Over the past five years, Nalcor has sold approximately 1500 GWh per year of power to export markets in New York. The path for these exports is a 265 MW firm transmission agreement with Hydro Quebec on the existing 735 KV network that leads from the Churchill Falls Generating station down to interconnects with New York and Vermont.
>
> [Morrison Park, Exhibit M-46, p. 31]

[192] The maximum capability of Nalcor's transmission link through Quebec is about 2,300 GWh of energy per year.

[193] Morrison Park noted that Nalcor would be reluctant to forego its contractual right to transmit energy through Quebec:

> ...however: it is unlikely that Nalcor would be willing to relinquish the contract it has for 265 MW of transmission access through Quebec, under almost any circumstances. The relationship between Newfoundland and Quebec has been so tumultuous because of the Churchill Falls-Hydro Quebec contract, and because of disputes over Newfoundland's desire to increase its transmission access through Quebec and Quebec's refusal to accommodate that request, that to relinquish the only available block of transmission access would be very unlikely. ...
>
> [Morrison Park, Exhibit M-46, p. 38]

[194] Morrison Park noted that in negotiating a price for Market-priced Energy from Nalcor, the Maritime Link would be at a price disadvantage to the Quebec path to New York, at least for the first 2,300 GWh of energy produced by Nalcor, for which it has access to transmission capacity through Quebec. The price advantage stems, in part, from much lower transmission line losses through Quebec of 5% versus 17% through NL and the Maritimes (via the Maritime Link) to New York. While Morrison Park noted that Labrador Market-priced Energy should exceed 2,300 GWh annually between 2017 and 2030, it expressed a caveat that new mining development in Labrador could erode the surplus substantially. According to the NL Government, it is possible that the existing Labrador surplus could be entirely consumed by new mining activity, at least in a high growth scenario.

[195] CanWEA also questioned the availability of Market-priced Energy from Nalcor, including access to the Recall Block from Churchill Falls:

> ... However, already in 2009, 170 MW of the recall power was required to meet Labrador loads. The remainder already has access to market, via a group of long-term firm transmission reservations totalling 250 MW held by Newfoundland Labrador Hydro (NLH, a Nalcor subsidiary) on the Hydro-Québec transmission system. The energy is marketed in the U.S. by Emera Energy.
>
> The NLH reservations expire in 2014, but Hydro-Québec's OATT provides a right of renewal. Given the scarcity of ATC out of Quebec, it would be surprising if NLH did not renew these reservations in order to maintain its access to this transmission path. The expectation that Nalcor will be marketing recall power over the Maritime Link thus appears speculative, at best.
>
> [CanWEA, Exhibit M-48, p. 28]

[196] NSPML did not challenge the evidence relating to Nalcor's commitments for the supply of energy for NL's future needs, including to the Labrador mining industry and to the Northeastern United States, except to say that NL would be producing an abundance of energy which would be available for export.

[197] At the hearing, the NSPML witness panel referred to yet other sources of NL energy, including a proposed 2,250 MW Churchill hydro development at Gull Island, three smaller hydro projects at Round Pond, Island Pond and Portland Creek (for a total capacity of about 79 MW), and potential wind farms on the island of Newfoundland. While NL only has 50 MW of wind on its system to date, Nancy Tower, Chief Executive Officer of Emera Newfoundland and Labrador, indicated there is interest in NL to add 5,000 MW of wind in the future. However, these projects are in the very early stages of design, they are years or decades from development, and may not even proceed. With respect to Gull Island specifically, an NL Government report from November 2012 identifies the Ontario market as the "best prospect" for Gull Island exports (Exhibit N-116). In any event, there was no evidence that Nova Scotia would be ensured access to this future energy if the projects proceeded.

[198] At one point, Mr. Janega seemed to imply that production from the 5,428 MW Churchill Falls Generating Station would be available to Nova Scotia:

> MR. JANEGA: ... And it can come from Upper Churchill. It could be Newfoundland and Labrador Hydro selling it. It could be Hydro Quebec selling it from Churchill Falls. We will be interconnected to over 6,000 megawatts of hydro capacity and we're going to sit and analyze none of that being available to Nova Scotia with a new transmission facility. ...
>
> MR. MERRICK: ... At this point, I'm merely wanting to get your views that if, in fact, that surplus energy is not available to Nova Scotia, will you not agree that that significantly alters the competitiveness of the deal or the ability of the deal, the Maritime Link part of the deal, to satisfy the test of being the lowest cost alternative?
>
> MR. JANEGA: Where is the surplus energy vaporizing or disappearing to?
>
> ...
>
> MR. JANEGA: There -- the evidence -- the evidence that's been presented speaks to 40 percent surplus from Muskrat Falls. That's 40 percent of the output of that facility. And we have a transmission facility that is going to connect us to energy that is being sold to the market every single day from a 5,400 megawatt plus generating facility.
>
> Where is the energy going if it -- if it's not going to market and we are now in the middle of that market and able to compete for the same electrons that New York, New England and now Nova Scotia will be able to compete to purchase that energy?
>
> The energy is there. It is absolutely there. And it is going to be produced. So why would we sit and think that there is no surplus energy?
>
> [Transcript, May 28, 2013, pp. 153-155]

[199] Notwithstanding NSPML's assertions, no evidence was presented to show that NSPI has a firm contract for such energy. In this sense, Mr. Janega's suggestion that NSPI could purchase Churchill Falls power from Hydro Quebec suffers from a similar defect as with the Nalcor Market-priced Energy (i.e., it has no contractual arrangement for the supply of such energy).

6.1.6.1 Findings

[200] While legitimate questions remain about the availability of Market-priced Energy from Nalcor over the first 24 years of the Maritime Link, the evidence clearly shows that there should be no shortage of Market-priced Energy when the Churchill Falls arrangement with Hydro Quebec comes to a conclusion in 2041. The Churchill

Falls Generating Station has a capacity of 5,428 MW, which over the past five years has averaged approximately 33 TWh per year (Nalcor's 65.8% share of the Churchill Falls Corporation would therefore yield approximately 22 TWh of energy supply in 2041).

[201] However, until 2041 arrives, there is, as Morrison Park described it, "substantial uncertainty" about the availability of a supply of Market-priced Energy from Nalcor for Nova Scotia.

[202] The Board finds that Nalcor's letter from Mr. Martin to Mr. Huskilson of Emera, dated May 16, 2013, provides no reassurance that Nova Scotians will be the recipient of Market-priced Energy from Nalcor. Indeed, it raises more doubt about Nalcor's future intentions for the Maritime Link. Mr. Martin refers on several occasions to exports of power over the Maritime Link, but remains non-committal about exports specifically destined for NSPI, and even fails to acknowledge NSPI's favourable negotiating position on price.

[203] In this respect, the Board takes note of the 35 year term of the contractual agreements respecting the supply of energy over the Maritime Link to NSPML (and ultimately to NSPI customers). Despite the projected 50 year useful life of the Maritime Link infrastructure itself, it was at Nalcor's insistence that the term of the NS Block was restricted to 35 years.

[204] In these circumstances, it is reasonable for the Board to be very concerned that Nalcor may have other plans for the Maritime Link after the 35 year term of the Commercial Agreements. Presumably, Nalcor would have been indifferent to a 50 year term if it intended to serve Nova Scotia throughout the useful life of the Maritime Link.

[205] Thus, against this context, it is fair to question Nalcor's commitment to providing NSPI with Market-priced Energy. It is not inconceivable that Nalcor could see the benefit of exporting Market-priced Energy to New England (rather than to Nova Scotia) on a short-term uneconomic basis in order to secure a more lucrative longer term arrangement with a counterparty in New England after the 35 year term of the Nalcor Transactions with Nova Scotia.

[206] In making these comments the Board is by no means intending to be critical of Nalcor's contractual stance on this issue. There may well be legitimate reasons for its position. Nalcor is justified in protecting its corporate interests (and the interests of Newfoundlanders and Labradorians) in its dealings with Emera.

[207] However, it is the Board's obligation to protect the interests of Nova Scotian ratepayers. More specifically, the Board is required in this proceeding to apply the test under s. 5(1) of the *ML Regulations*. As noted previously, in the absence of Market-priced Energy, the ML Project is not the lowest long-term cost alternative for electricity for ratepayers in Nova Scotia.

[208] In reviewing the importance of the availability of Market-priced Energy to the Application, the Board referred back to Figure 4-4 of the Application, which is outlined earlier in this Decision. The fundamental assumption which underpins the Application is that NS customers will enjoy a blended rate for electricity which is comprised of a weighted average of the costs reflecting the NS Block and the projected amounts and prices for Market-priced Energy over the 35 year term.

[209] In response to NSUARB IR-37, NSPML provided a breakdown of the annual energy quantities associated with the NS Block supplied over the Maritime Link

and the purchase of Market-priced Energy, as depicted on Figure 4-4. The Market-priced Energy consists of projected imports over the NB/NS intertie and from Newfoundland and Labrador, with about 70% of Market-priced Energy sourced from Nalcor, via the Maritime Link, over the course of the 35 year term.

[210] After the supply of Supplemental Energy is completed in five years, the NS Block will represent 895 GWh of energy annually to Nova Scotia. However, for most years beyond 2022, the amount of Market-priced Energy Figure 4-4 assumes is acquired from Nalcor approaches twice the amount of energy being provided under the NS Block. Under a "Base Load" scenario, Market-priced Energy from Nalcor is projected to represent 1,529 GWh of energy in 2023, increasing to 1,732 GWh in 2040. As a percentage of the NS Block, Nalcor Market-priced Energy will increase from 170% of the NS Block in 2023 to 193% in 2040.

[211] The increasing reliance on the availability of Market-priced Energy from Nalcor during the 35 year term further exacerbates this situation. In the 2030s, NSPML's projections, which form the financial basis of the Application, show that NSPI will be receiving almost twice as much Market-priced Energy from Nalcor than the NS Block itself. This will be occurring during a time period when the evidence suggests that the supply of Market-priced Energy from Nalcor may be uncertain. In the Board's opinion, this underscores the importance of ensuring access to Market-priced Energy from Nalcor.

[212] The fact that Nalcor has been unwilling to commit to the sale of Market-priced Energy to NSPI has put the Board on inquiry about Nalcor's future intentions for this energy. This leaves NSPI in the unenviable position of having no contractual

certainty of obtaining Market-priced Energy from Nalcor. However, NSPML/Emera have accepted no risk as a result of that contractual uncertainty. As they have structured the deal, that risk falls entirely to Nova Scotia ratepayers.

[213] In the Board's view, NSPML's assertion that there is no need for contractual terms respecting the supply of Market-priced Energy from Nalcor is entirely inconsistent with NSPML's submission that the Other Import alternative should be discounted because there is no long-term, fixed price energy available from Hydro Quebec. In the Board's opinion, the two situations are similar because in both instances the counterparty has elected to leave its options open for the future instead of committing to a long-term supply contract with NSPI for energy at market prices.

[214] The Board finds little comfort from NSPML's response to Undertaking U-11 to the issue of Market-priced Energy. In Undertaking U-11, NSPML was asked by Board Counsel to provide a Strategist run analysis reflecting no purchase of Nalcor Surplus Energy by NSPI and no export of Nalcor Surplus Energy through the Maritime Link and the NS/NB intertie. This would mean that NSPI would not have the "netting" benefit of increased imports over the NS/NB interconnection.

[215] As noted by counsel for the Industrial Group in its Final Argument, the absence of Market-priced Energy required NSPML to model increased levels of wind into its revised Undertaking U-11 scenario for the ML Project. As a result, as the level of wind increases, the revised ML Project scenario becomes susceptible to increased wind integration costs, in like fashion to what NSPML stated would occur with the Indigenous Wind option.

[216] Based on its review of Undertaking U-11, the Board observes that the NPV analysis of the ML Project is significantly impacted if no Market-priced Energy flows from Nalcor over the Maritime Link. For instance, for the "Base Load" case over the indefinite Study Period, the NPV result for the ML Project is $1.422 billion more expensive without the Market-priced Energy than the Application's proposed scenario where such energy is flowing over the Maritime Link. Even for the "Base Load" case over the 25 year Planning Period, the NPV result is $706 million more expensive than proposed in the Application.

[217] In its response to Undertaking U-11, NSPML only compared the ML Project to the Indigenous Wind "Base Load" scenario. In so doing, the ML Project was portrayed in its most favourable light as against an alternative having the most extreme assumptions applying to it. The Indigenous Wind option unquestionably performs at its worst in a "Base Load" case, which is, in effect, a high load case, where the system requires increased integration costs to accommodate higher levels of wind.

[218] When, instead, the NPV results of the ML Project (without Market-priced Energy) are compared to Indigenous Wind "Low Load" scenarios, the position of the ML Project is much weaker as compared to the alternatives and the inference can be made that more of Synapse's Strategist runs would outperform the ML Project. Interestingly, compared to the "Base Load" Other Import scenario (which NSPML did not mention in Undertaking U-11), the NPV results of the revised ML Project are almost $600 million worse over the 25 year Planning Period, and over $1.1 billion worse over the Study Period.

[219] Needless to say, the elimination of the Market-priced Energy from the ML Project would have a significant negative impact on its NPV. Such a result would bring more of the Strategist runs conducted by Synapse below the NPV of the ML Project. While only two of Synapse's runs performed better than NSPML's original scenario (for Low Load), it is a fair inference that eliminating the Market-priced Energy from the analysis brings many of Synapse's close Strategist runs into a superior position to the ML Project.

[220] In his testimony at the hearing, Mr. Colaiacovo of Morrison Park testified that a ML Project scenario without Market-priced Energy would lead them to change their original opinion of the Application. In cross-examination by Mr. Levy of CanWEA about Figure 4.4 of the Application, Mr. Colaiacovo stated:

> MR. LEVY: Okay. If you turn to Figure 4-4, the Nova Scotia block taken as itself, so ignoring the blended rate and ignoring the surplus energy, would you consider this to be fair value for ratepayers?
>
> MR. COLAIACOVO: The Nova Scotia block on its own, as you can see in that figure, is quite expensive in comparison to many other forms of energy. And so if this project were expected, in a reasonable range of scenarios, to result in only Nova Scotia block energy, then it would have to be characterized as a very expensive option and, you know, I think we would have to make a decision accordingly.
>
> [Transcript, June 6, 2013, p. 2547]

[221] Morrison Park reiterated their view in questions from the Board:

> MR. DEVEAU: ... And the last question, you were asked questions earlier today about the Figure 4.4, the famous Figure 4.4 that we've been referred to several times.
>
> MR. WALKER: Yes.
>
> MR. DEVEAU: And I think you agreed that the Nova Scotia block itself was quite expensive in relation to the other scenarios?
>
> MR. WALKER: Yes.
>
> MR. DEVEAU: And you were referred -- you were asked, generally, if only the Nova Scotia block was purchased what would happen. And I think your words, close to what you said was something to the effect of, "We'd have to decide accordingly." Do you have an opinion to express on that, if the Nova Scotia block was -- just the Nova Scotia block was purchased? First of all, would that be a material matter that might affect your opinion?

> MR. COLAIACOVO: Absolutely. The -- I think the reality here is if this application was an application for $1.5 billion in capital expenditures in order to receive just the Nova Scotia block; in other words, if it was a 168 [170] megawatt transmission line instead of a 500 megawatt transmission line, would we come to a different conclusion? Without prejudicing our report, but yes. I believe we would have come to a different conclusion.
>
> ...
>
> If we were told, if new information came to light that said, you know, well, all of that previous analysis that we had done about the availability and price of additional power is incorrect; that, in fact, you know, there will be no additional power, would we be forced to revisit our views? Absolutely, we would be forced to revisit our views. [Emphasis added]
>
> [Transcript, June 6, 2013, pp. 2575-2576]

[222] The Board observes, for the purposes of this analysis, that the absence of any Market-priced Energy flowing over the Maritime Link would, for all intents and purposes, effectively result in a Maritime Link with a capacity of 170 MW instead of 500 MW.

[223] Taking all of the above into consideration, the Board concludes that the availability of Market-priced Energy is crucial to the viability of the ML Project proposal as against the other alternatives. Without the Market-priced Energy, the ML Project is clearly not "robust". More importantly, the Board finds that without some enforceable covenant about the availability of the Market-priced Energy, the ML Project does not represent the lowest long-term cost alternative for electricity for ratepayers in Nova Scotia.

[224] The Board has considered how it should address this significant risk to the viability of the ML Project as against the other alternatives. It could, under the *ML Regulations*, simply reject the Application, but that would not be the responsible result and would not be a productive outcome of the regulatory process.

[225] In the Board's opinion, the price of future Market-priced Energy is not the real concern, as alleged by Intervenors. The Board understands and accepts that it may be advantageous to make opportunity purchases of Market-priced Energy, when it

is to NSPI's benefit to do so. In that regard, the Board's primary concern is not exposing a relatively small portion of NSPI's energy portfolio to market prices, rather the concern is that the advantageous opportunity to purchase cannot take place, if there is no Market-priced Energy to buy.

[226] The Board will impose a condition relative to the availability of Market-priced Energy over the 35 year term. In the Board's opinion, such a condition should not create any practical difficulty because it would simply codify what NSPML asserts is the effect of the arrangement in any case. It would also confirm what NSPML already states is Nalcor's view of their future relationship.

[227] This is a simple remedy to the fundamental risk underlying NSPML's Application for approval of the ML Project. If no such condition was imposed, the Board would fail in its regulatory oversight by approving an application that could potentially be commercially disadvantageous to NS ratepayers.

[228] Accordingly, the Board directs as a condition to its approval of the ML Project that NSPML obtain from Nalcor the right to access Nalcor Market-priced Energy (consistent with the assumptions in the Application as noted in NSUARB IR-37 and Figure 4-4) when needed to economically serve NSPI and its ratepayers; or provide some other arrangement to ensure access to Market-priced Energy.

[229] Further, the Board expects that any such confirmation of Market-priced Energy will come at no additional cost to ratepayers, because this assurance was described by NSPML during the hearing as representing the intention of both Nalcor and Emera in the deal presented in the Application. In effect, the Board is simply attempting to get legal certainty over what NSPML has already assured Nova Scotians

will be the result of the deal. Moreover, the imposition of any additional cost could jeopardize the ML Project as the lowest long-term cost alternative and, in the end, would not be the deal proposed in the Application.

[230] The Board will make itself available on an expedited schedule to review commercially reasonable terms submitted by NSPML and Nalcor and for comments by the Intervenors.

[231] The Board notes that NSPI will be required to act prudently in the acquisition of Market-priced Energy as it would with all other fuel related decisions. Decisions related to the purchase of Market-priced Energy will be subject to the provisions of NSPI's Fuel Adjustment Mechanism and the oversight that occurs under that mechanism.

6.2 Is the ML Project consistent with obligations under the *Electricity Act*?

[232] Under s. 5(1)(b) of the *ML Regulations*, a condition precedent to the Board's approval of the ML Project is a finding that the project is consistent with obligations under the *Electricity Act*.

[233] As noted earlier in this Decision, NSPI must meet the RES 2015 and RES 2020 levels set out in the *Renewable Electricity Regulations*.

[234] NSPML submits that the ML Project will enable NSPI to meet RES 2020 obligations.

[235] As noted in Clause 6A(2) of the *Renewable Electricity Regulations*, power and energy from Muskrat Falls is deemed to be renewable energy for purposes of the *Regulations* and, further, NSPI must purchase that energy if the ML Project is approved by the Board and the Muskrat Falls Generation Station is in operation. No party

indicated that power and energy from the ML Project was not consistent with the obligations under the *Electricity Act*.

[236] Accordingly, the Board finds that the ML Project is "consistent with the obligations under the *Electricity Act*."

6.3 Is the ML Project consistent with any obligations governing the release of greenhouse gases and air pollutants under the *Environment Act*, the *Canadian Environmental Protection Act* and any associated agreements?

[237] Under s. 5(1)(b) of the *ML Regulations*, a condition precedent to the Board's approval of the ML Project is a finding that the project is consistent with any obligations governing the release of greenhouse gases and air pollutants under the *Environment Act*, the *Canadian Environmental Protection Act* and any associated agreements.

[238] The obligations respecting emissions are summarized in Section 3.3 earlier in this Decision.

[239] No party to the proceeding suggested that the ML Project was inconsistent with any obligations governing the release of greenhouse gases and air pollutants under the *Environment Act,* the *Canadian Environmental Protection Act* and any associated agreements.

[240] Having reviewed the relevant provisions the Board finds the ML Project is consistent with those obligations.

6.4 Are the engineering and design details included in the Application sufficient to enable the Board to approve the ML Project?

[241] The *ML Regulations* state that the application for the ML Project must include "engineering and design details sufficient to enable the Review Board to approve the Maritime Link Project...".

[242] In section 3.0 of its Application, NSPML stated that:

> The engineering work and design work for the Maritime Link are ongoing at this time...
>
> [Application, Exhibit M-2, p. 39]

and that sections of the Application:

> ...include reference to technology alternatives which are still under consideration in many cases, pending further engineering assessment or evaluation of supplier proposals.
>
> ...
>
> The project design scope and budget are at the conceptual level, which represents DG2 at the time of this application. Conceptual design ensures that elements of the project are suitable and appropriate to include in the project scope and will function to meet the design criteria advanced at this level of engineering completion. ...
>
> [Application, Exhibit M-2, pp. 39-40]

[243] As described and depicted in Figure 3-4 of the NSPML Application, the Maritime Link will consist of two broad groups of facilities. This includes facilities that are needed for the HVDC transmission link and facilities that are needed to connect that link to the AC transmission systems in Newfoundland and in Nova Scotia:

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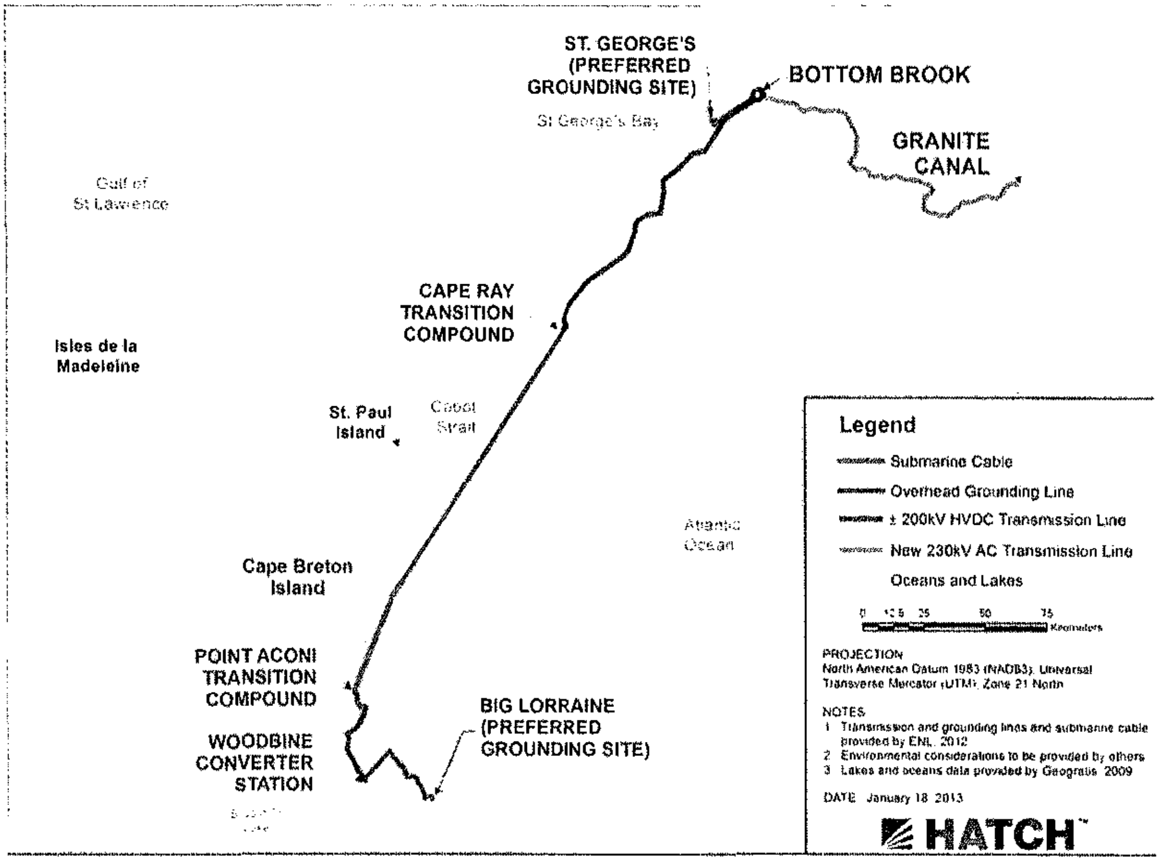
Figure 3-4 Maritime Link Project



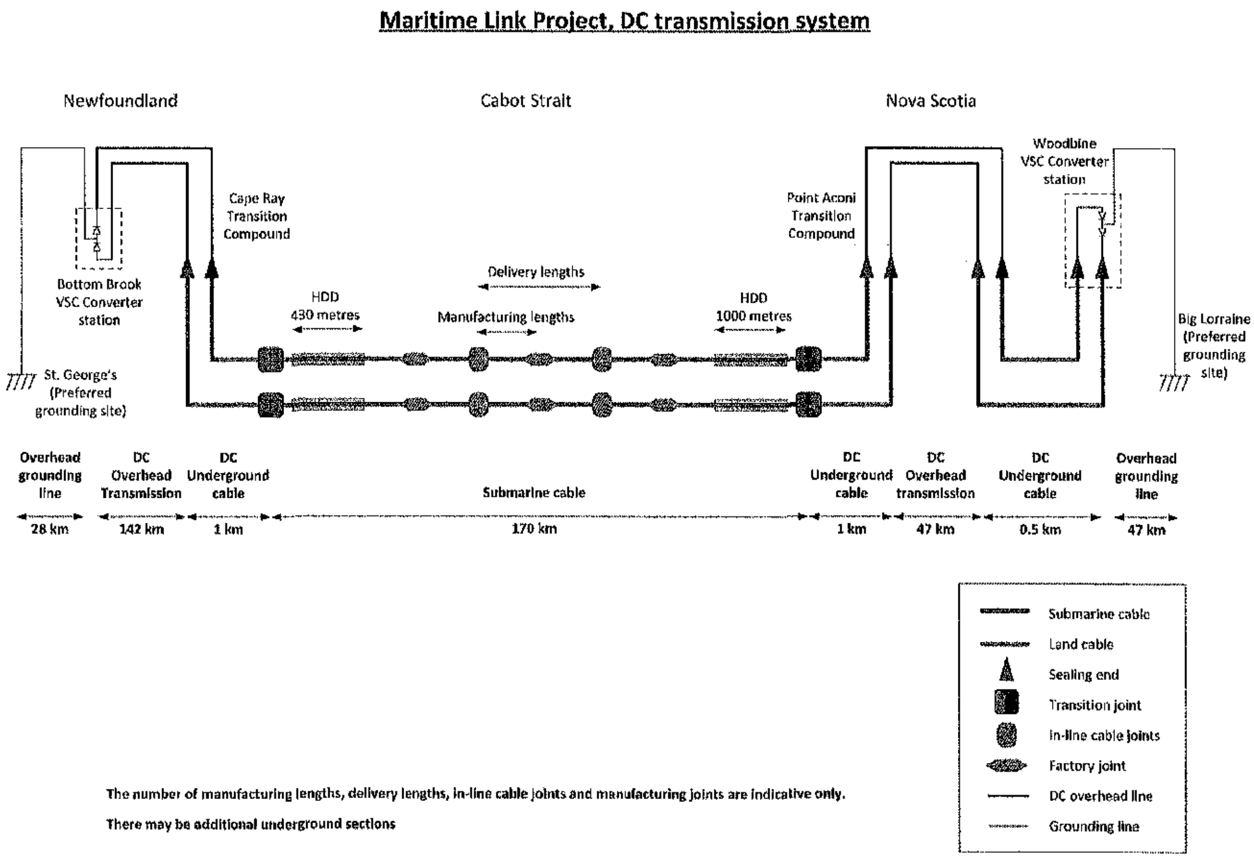
[Application, Exhibit M-2, Figure 3-4, p.58]

[244] The transmission and related facilities of the Maritime Link will include:

- 160 km of new 230 kV overhead AC transmission line between Granite Canal and Bottom Brook, along with limited system upgrades;
- new substations adjacent to the existing Granite Canal Generating Station and Bottom Brook Substation;
- AC/DC converter stations at Bottom Brook in NL and Woodbine in NS;
- shoreline grounding lines and stations in NL and NS;
- two 170 km HVDC subsea cables (positive pole and negative pole) crossing the Cabot Strait;
- approximately 1 km of underground cables in NL and in NS;
- overhead to underground transition compounds;
- 142 km of overhead DC transmission line in NL;
- 47 km of overhead DC transmission line in NS; and
- expansion of the Woodbine Substation in NS.

[245] The overhead HVDC lines will include two separate shield conductors which will contain a fibre optic core for communication purposes. Subsea cable landing sites have been chosen as Cape Ray in NL and Point Aconi in NS. Also, the preferred shoreline grounding sites have been identified as St. George's in NL and Big Lorraine in NS. Approximately 28 km of overhead grounding line will connect the Bottom Brook converter station to the St. George's grounding site, while about 47 km of line will be needed to connect the Woodbine converter station to the Big Lorraine grounding site. A schematic diagram of this cable system was provided by CCI, the Board Counsel's consultant:

Figure 1. Schematic diagram of the cable system



[CCI, Exhibit M-42, Figure 1, p. 14]

[246] NSPML has stated that due to economics and system characteristics in NL and NS, the HVDC system will utilize Voltage Source Conversion ("VSC") technology, instead of Line Commutated Conversion ("LCC") technology. This system will be operated in bipolar mode at +/- 200 kV and will be capable of transmitting up to 500 MW of electrical power in bipolar mode, or 250 MW in monopolar mode utilizing ground (sea) return.

[247] As of the hearing date, the choice of subsea cable type was not determined. The Applicant's RFP provided potential bidders with the option of supplying either Mass Impregnated ("MI") paper insulated cable or Cross-Linked Polyethylene ("XLPE") extruded plastic insulated cable, neither of which will include a return conductor nor embedded communication conductor. Although XLPE cables offer lower initial costs, the operating history at higher voltage levels is not as long and successful as MI cables. NSPML's project cost estimates are based on the assumption that MI cables will be used.

[248] In order to reliably integrate the HVDC link into the existing AC system, a new 160 km 230 kV transmission line will be required between Bottom Brook and Granite Canal in NL along with substation expansions at both of those locations. In addition, Woodbine Substation in NS will require expansion to accept interconnection of the AC/DC converters, re-routing two existing 230 kV lines into Woodbine Substation, and installing a redundant second 345/230 kV transformer to provide increased capacity for reliable transfer of power from the 345 kV system to the 230 kV system.

[249] Furthermore, additional transmission network upgrades will be required in NS to accommodate transmission flows of up to 330 MW through NS into New

Brunswick or beyond into New England. NSPML has estimated these NSPI network upgrade costs to be $31.5 million, which it considers to be part of the Nalcor Transactions, but noted that NSPI will be seeking regulatory approval consistent with current rules for capital filings. This cost has not been included in NSPML's alternative analysis.

[250] In its Closing Brief, NSPML stated:

> The additional system reinforcements in Newfoundland and in Nova Scotia have been demonstrated to be necessary for the reliable operation of the Maritime Link, and are not needed by Nalcor to meet their domestic power needs in Newfoundland.
>
> [NSPML Closing Brief, p. 40]

[251] However, if any of these transmission costs are not fully recovered through the transmission tariffs, neither Nalcor nor NSPML will bear responsibility since the shortfall will be borne by NSPI ratepayers.

[252] NSPML has also stated that all technologies being proposed for the ML Project have been proven in similar circumstances and at similar voltage levels and power transmission levels to the ML Project.

> The component parts of the Maritime Link are all technically feasible. They consist of proven equipment in proven configurations. The integrated facilities of the Maritime Link Project will deliver reliable and dependable service.
>
> ...
>
> ...the proposed technologies have been deployed successfully on projects similar to the Maritime Link, and are well proven in similar applications.
>
> [Application, Exhibit M-2, p. 67]

6.4.1 HVDC Design Concept

[253] The evidence filed by Dr. Narain Hingorani, on behalf of Board Counsel, was focused on the HVDC design concept and project cost estimates for the land components of the ML Project. More specifically, this included the AC/DC converters, overhead DC transmission lines, underground DC cables, and the grounding sites.

[254] A number of questions and concerns related to the HVDC design and technology were expressed by Dr. Hingorani as noted below:

- Considering that the ML Project has large segments of overhead HVDC line, is VSC technology a better choice than LCC technology?
- Is high speed fault clearing required?
- Can reverse power flow from NS to NL be accommodated?
- Is a hybrid arrangement utilizing a combination of overhead line and underground cable the correct choice?
- Is the ML Project technically feasible and is the technology proven?
- Does LCC require dynamic reactive power support and if so, is that sufficient reason to reject LCC?
- If VSC is chosen, should fast restart using AC breakers and rapid reclose for overhead line faults be required?
- Is the $450 million estimate for two VSC converter stations and related infrastructure reasonable?
- Is the choice of shore grounding sites appropriate?

[255] Some of those questions were adequately addressed in the NSPML Application, while others were explored during two rounds of IRs and in NSPML's Reply Evidence, Exhibit M-83.

[256] Dr. Hingorani accepted that potential disadvantages of VSC technology would not be significant if the procurement included auto-reclosing of the AC breakers and restart of the DC link after an initial DC line fault, plus reduced voltage restart by

operator intervention if the first restart failed, as proposed by NSPML. This configuration would not include high-speed electronic fault clearing.

[257] Dr. Hingorani's concern regarding a significant reliability impact on customers associated with delayed restart of the DC link under a VSC scenario was also reduced by the understanding that the NS Block delivery will not be affected by either short or long-term single-pole outages on the DC link. However, that concern still remains when considering access to larger blocks of Nalcor Market-priced Energy which exceed the capacity of single-pole operation. Under those circumstances, Dr. Hingorani suggested prudence in procuring state-of-the-art technology which would provide for future high speed fault clearance, rapid restarts and reduced voltage restarts.

[258] On the issue of dynamic reactive support requirements for LCC technology, NSPML stated, in its Reply Evidence, that dynamic reactive power support would be needed in Cape Breton to provide greater assurance of reliable system performance during critical outages in the AC system. Furthermore, NSPML stated:

> With the added cost of 200MVA of dynamic VAr support at Bottom Brook, plus the costs associated with dynamic VAr support in Cape Breton, there is no premium for VSC converters compared to LCC converters.
>
> [NSPML Reply Evidence, Exhibit M-83, p.44]

[259] Regarding the converter cost estimate, NSPML provided the following explanation:

> ...the cost estimate for the Maritime Link Converters and related infrastructure is $450 million. NSPML's cost estimate for the converter stations include more than the converters alone and may be the reason for the concerns raised by Dr. Hingorani.
>
> In response to these concerns, NSPML notes that the reference project costs offered by Dr. Hingorani did not include the costs of ac substations and other associated facilities that were included in the Maritime Link estimate.
>
> ...

> The cost included in the project estimate took into consideration the final engineering estimate for the converter stations. In addition, the "Converter Stations and related infrastructure" line item in the project estimate included estimates for the substations/switchyards at Woodbine, Bottom Brook and Granite Canal, the grounding sites in Newfoundland and Cape Breton, the overhead/underground transitions in Newfoundland and Cape Breton, the integrated telecommunications system and control center upgrades, and the access roads for the project.
>
> ...
>
> The request for EPC bids for the converter stations has now been released to the vendor community for bidding, and it is anticipated that firm-price bids will be obtained by the third quarter of 2013.
>
> [NSPML Reply Evidence, Exhibit M-83, pp.45-46]

6.4.2 Submarine and Land Cables

[260] Evidence filed by Cable Consulting International Ltd. ("CCI"), on behalf of Board Counsel, was focused on the submarine and land cables. Their review of the Application addressed specific aspects of the cable system design which included the cable insulation type, cable manufacture, cable system installation and protection, and cable system cost.

[261] The following concerns were highlighted by CCI:

- NSPML's RFP for the submarine cable contained no statement on the availability level required to be achieved by the submarine cable link. CCI indicated that this target should be stated and that bidders should demonstrate by calculation that their cable and installation is designed to achieve that availability requirement.
- NSPML's RFP for the land cable was lacking in some of the performance requirements. CCI noted that the RFP should have included information regarding maximum or minimum ambient temperatures, requirements for protection of buried land cables, routine testing of the extruded anti-corrosion

insulating over-sheath (jacket), and the configuration in which the land cables are to be laid.

- The RFP contained inconsistent requirements for the duration of qualifying service experience for MI cable (10 years) and polymeric insulated cable (5 years). CCI considers that the period of qualifying service should be the same for both types of cable.
- NSPML's proposal to permit a relaxation in the International Council on Large Electric Systems ("CIGRE") TB 219 and TB 496 360-day prequalification test duration for polymeric ("XLPE") cable.
- Cable spacing and installation, the requirement for circuit availability, and associated n-1 redundancy should be stated by NSPML before the design of installation and protection is decided. In this case, n-1 redundancy refers to continued operation if one cable failed.

[262] CCI noted that NSPML's RFP invited bidders to recommend the insulation technology of their choosing, with supporting technical specifications to prove the long-term viability of the proposal. Based on responses received, NSPML is evaluating bids on both the XLPE and MI cable types. In response to CCI IR-40, NSPML advised that no bids were received for the newer type polypropylene paper laminate ("PPL") tape insulated MI cables.

[263] NSPML acknowledged that XLPE insulated DC cables have not yet accumulated the same amount of operating history as MI insulated cables.

[264] Although NSPML stated that the components of the ML Project are all technically feasible and they consist of proven equipment in proven configurations for

the submarine cable, CCI accepted this to be correct for MI cables, but noted that it is incorrect for DC polymeric cables.

[265] Regarding n-1 operation (i.e., transmitting power in monopole mode with only one of the two poles in service during emergency situations), CCI noted that the availability percentage will be greater under the following conditions:

- If third party damage or damage due to an internal fault affects only one of the two cables;
- When only one of the submarine cables must be lifted from the seabed for repair without the other cable having to be taken out of service;
- When a damaged land cable can be accessed and repaired with less interruption to the power flow in the other cable.

[266] On the issue of cable failure and repair, NSPML's response to CCI IR-35 noted that no modeling was undertaken respecting a cable failure requiring recovery of the cable from the seabed, throughout the life of the cable. However, NSPML estimated that the outage time necessary to effect a repair to the cable and return the cable system to service is two to eight months.

[267] In its evidence, CCI highlighted concerns related to cable manufacture:

> To reduce the risk of latent manufacturing defects causing failures at a later stage in manufacture or in service, rigorous compliance with quality procedures is essential. Close involvement is recommended of NSPML's staff in the agreement of the manufacturing specification and the inspection and test plan, and in the continuous witnessing at the manufacturer's cable factory during the period of testing and manufacture. NSPML's RFP includes requirement for such facilities to be afforded by contractors to NSPML personnel.
>
> [CCI, Exhibit M-42, pp. 34-35]

[268] Concerns were also expressed regarding cable installation and protection. CCI stated that:

> NSPML has not specified the installation configuration in which the submarine cables are to be laid. NSPML has stated that each of the two cables will be installed within a separate HDD at the landing positions.
>
> ...
>
> The maximum installation length which can be installed during a single installation campaign is commonly limited by the maximum weight of cable that can be stored aboard the installation vessel. NSPML has not declared the cable weight or whether the cable can be laid in a single length without the need to make rigid sea joints....Rigid sea joints are prospectively less reliable than cable.
>
> [CCI, Exhibit M-42, pp. 35-37]

[269] Regarding cable cost, NSPML's P50 estimate for marine cost was given as $300 million (CAD), but a more detailed breakdown was not provided so CCI was not able to review NSPML's capital cost estimates. CCI noted that bids for the cable closed on July 9, 2012 (Ref. CCI IR-34) so NSPML should have been able to analyze those bids and formulate a cost estimate before filing its Application. NSPML has stated that its cost estimate was based on using MI cable in a bundled configuration for the submarine cable across the Cabot Strait. However, NSPML also stated that its current plan:

> ...is to lay the cable unbundled. Additional costs relating to unbundling remain consistent with the original estimate of $1.52 billion used for the ML Alternatives Analysis, but will be updated upon award of the cable supply.
>
> [Undertaking U-15, June 4, 2013]

[270] One of the key issues raised by CCI is NSPML's availability target for the Maritime Link of 95-97%.

[271] In April 2009, CIGRE published a comprehensive technical brochure, CIGRE TB 379, titled "Update of Service Experience of HV Underground and Submarine Cable Systems". The average failure rate noted in that publication is 0.12 failures per 100 circuit km per year, based on 49 failures from 1990 to 2005 for all types of cable. Also, the range of outage times contained in CIGRE TB 379 is ≤1 month to ≥6 months. CCI noted that applying the CIGRE failure rate gives, on average, a period

between failures for the 170 km Maritime Link of 4.9 years. Furthermore, if the cables are bundled and buried in close formation such that both pole cables are out of service for the complete duration of the repair, and if the higher repair time given by NSPML of 8 months is used, this is equivalent to an availability of 86%.

[272] In its Opening Statement CCI again raised several of its concerns regarding the submarine cable, availability target, and NSPML's reference to "proven equipment in proven configurations". CCI stated:

> NSPML did not provide any design summary or details of the designs, even non-attributable to individual suppliers. If the Maritime Link is approved, NSPML would have freedom to place a contract for a cable system design from a range of, as yet unknown, possibilities without a presentation to NSUARB confirming that the availability target for the complete Maritime Link of 95-97 percent will be achievable.
>
> The engineering risk of a submarine cable link is high and although this can be reduced, it cannot be eliminated.
>
> ...
>
> NSPML...has not committed to the wide spacing of the cables; wide spacing is a key requirement for continuous monopole operation whilst one of the two cables is being repaired.
>
> ...
>
> Although promising, DC XLPE cannot yet be regarded as fully service proven (section 4.2 of the CCI evidence). NSPML's statement that "the component parts of the Maritime Link consist of proven equipment in proven configurations" (Application, page 67) is considered to be an unfair summary with respect to 200 kV DC XLPE cable.
>
> [CCI Opening Statement, Exhibit M-98, pp. 2-3]

[273] CCI repeated the need for independent engineering reviews and recommended that such reviews be made a condition of any Board approval of the ML Project.

[274] During the hearing, some of the CCI concerns were further explored. One of those concerns was in relation to the reliability and availability calculations for the submarine cable. NSPML explained during the hearing that its protection and mitigation measures were deemed sufficient to support a reduction of the CIGRE failure rate of

0.12 failures per year per 100 km down to a range of between 0.04 and 0.08. CCI was asked to comment on that position.

MR. GREGORY: Okay. Well, first of all, the 0.32 was the average from an earlier and older survey of CIGRE, and it's quite correct to say that there was a higher fault rate then and fewer cables, very few, were protected by burial at that date.

So the recent CIGRE study, which gives the average of 0.12, is based on a mixture of not quite so old circuits which may or may not have been buried and more modern ones which have been buried, and that the drop in the failure rate reflects the better protection. But it also reflects improvements in the engineering and design, particularly of the factory joints.

Often subsea cables are not made in one long length in the factory. They are made as long as they can get them and then they join, splice two lengths together to make one long length, for example.

And so there are several factors which have improved the failure rate.

And then they've gone on from the .12 figure to try and analyze how their proposed design, in my understanding, will reduce the failure rate below .12. I think there is some grounds to do that because not -- because in the present study, not every one of the cables was buried.

It's also indicated that most of the failures are due to external damage. In other words, protection can reduce the failure rate.

So I think it's reasonable to reduce it. The question is by how much. And they have given the two figures .04 and .08.

And below, I can see that they've said they've taken a conservative approach and halved the figure to .06 and then taken a sensitivity of plus or minus 0.02.

I think that's reasonable, and I wouldn't have a strong problem with that.

MR. DEVEAU: Okay. So in terms of your suggestion when Mr. Dhillon was asking you questions that you didn't view their assertion that there would be no failures, that, you feel, is unreasonable.

MR. GREGORY: Yes, it's completely unreasonable.

MR. DEVEAU: Okay. But in terms of the rates that they're suggesting, the mid-range of .06, is not necessarily unreasonable, and you say that it may be reasonable.

MR. GREGORY: Yes, I would accept that as a sensible target.

MR. DEVEAU: Okay. And obviously, that would affect the length of the interval. For instance, for a 0.12 failure rate your figure was 4.9 years. For .04 it would obviously be three times that; correct? The length ---

MR. GREGORY: Yes.

MR. DEVEAU: The intervals between the failures.

MR. GREGORY: Yes.

MR. DEVEAU: Okay. Thank you.

MR. GREGORY: So I think, as Mr. Outhouse said, it should be three times longer, and I think he said very nearly 15 years ---

MR. DEVEAU: Right.

MR. GREGORY: --- 14.71 years, I think.

MR. DEVEAU: Right. Thank you.

[Transcript, June 6, 2013, pp. 2479-2482]

[275] CCI was also asked whether their concerns regarding the submarine cable selection had changed based on the explanations provided by NSPML earlier in the hearing. In response, CCI stated:

> Well, it's a compliment to us, I guess, that they said that they share our concerns and they will consider them, but there is no commitment. They have left, as I understand it, their options open to choose mass-impregnated or polymeric/XLPE cable or to space the cable close together or wide apart. And I think the most important thing, in terms of the cable system, is to design a cable system that is reliable and that can be and is repairable.
>
> And I think that should be checked by an independent engineering consultant and the Board should have sight of that. Once the contract is let, everything is set.

[Transcript, June 6, 2013, pp. 2472-2473]

[276] Upon further questioning about possible duplication of the independent engineering review that will be completed for NSPML and the review proposed for the Board, CCI provided the following explanation:

> Well, what my feeling is that they have proposed, they have said to have chosen Mr. MacPhail, a consultant as their independent engineer. And if in his terms of reference, amongst his other work, he is required to evaluate the total engineering scheme for the cable, that's the design, the manufacture, the installation, the laying, and the protection and the repairability, and he justifies that with relation to known authorities, and he shows that report to yourselves, I think, in my view that is sufficient.
>
> ...
>
> There is no need for two but is -- one is sufficient.

[Transcript, June 6, 2013, pp. 2473-2474]

[277] In its Reply Evidence, NSPML noted that several CCI recommendations:

> ...relate to the provision of satisfactory independent engineering reviews of specific aspects of the Project to be provided to the UARB by NSPML. NSPML will be pleased to provide these reviews to the Board once they have been completed...Other recommendations relate to cable options (MI v. XLPE) and as such, they may not be applicable once decisions are finalized about the type of cable for the Project, however NSPML will ensure they are respectively addressed during the selection and design process.
>
> [NSPML Reply Evidence, p. 42]

[278] CCI's recommendations regarding independent engineering reviews and reports to the Board will be addressed more specifically in section 6.13 of this Decision.

6.4.3 Project Management, Construction, and Scheduling

[279] Evidence by Enerco Consulting and AHB 2000 Inc. was filed on behalf of Board Counsel and was jointly submitted by both consultants, who will be referenced in this Decision as "Enerco". Their review of the Application was focused on issues related to project management, construction, and scheduling risks for the ML Project.

[280] Specific concerns expressed by Enerco include:

- Project management: Staffing of positions for Phase 3 of the project (Q4 2012 - Q3 2013) was incomplete, which may become a problem due to difficulty in recruiting qualified management staff, technicians, and qualified labour in a tight schedule.
- Construction: Only the Bottom Brook and Woodbine converter stations were shown as critical elements that govern the overall project schedule, but the subsea cable activities should also be considered as critical elements based on uncertainties due to weather, underwater conditions, cable protection, and unanticipated problems which will only be known when the work is being

carried out. In response to Enerco IR-24, NSPML stated that it considers the potential for delay during the 2016 season to be low.

- Scheduling risks: Although tactical and strategic risks were identified, NSPML's register of 275 risks was not fully quantified. Also, Enerco noted that NSPML attributed an overly optimistic low value to the worst delay risks associated with marine work in a narrow marine weather window.

[281] Enerco concluded that numerous uncertainties and serious risks exist, but it is not known how they were quantified by NSPML.

> ...the uncertainties are numerous and the risks listed are real. Comments in the Independent Project Review report and in the ML January 2013 report confirm the existence of these uncertainties.
>
> The result of the Cost and Schedule Risk Assessment shows a total cost exposure that in our opinion does not fit with the qualitative assessment and that seems somewhat low for a project.
>
> The result of the Time Risk Assessment Ranging Sheet implies a tight schedule without sufficient float.
>
> [Enerco, Exhibit M-50, p. 11]

[282] During questioning at the hearing, it was pointed out that NSPML indicated it had considered Enerco's suggestions and recommendations and had made changes, or was in the process of making changes, related to those suggestions. Enerco was asked whether they now considered that some of their issues had been dealt with.

> MR. WIEBE: Well, we believe that -- that the issue is the risk and schedule. And we believe that -- that they have not been forthcoming and open with all the information. So we are caught in the middle where we're uncertain of -- of where they stand in those two issues.
>
> [Transcript, June 3, 2013, p. 1623]

[283] Enerco was also asked to provide some additional context regarding their reference in the evidence to the use of regular independent project reviews.

MR. WIEBE: So our feeling is that it is useful for major projects like this to have independent reviews whenever there's a major decision point to be reached.

MR. BOISSET: And now to add something else ...

And usually for the cost first, you have the cost validated by third party. I haven't seen that there. And also, as far as a risk analysis is concerned, risk analysis is taken very seriously by all instances, particularly in British Columbia, for example, where any risk analysis is subject to the government own agency.

And they want to be sure that whenever there is a risk analysis, the people around the table who are kind of evaluating the cost of the risks are people who are not only the project people who have to be there because they know the project, but also are outside people, experts who are outside so that the evaluation of the cost, which is something quite subjective, may be as -- quite as precise as possible thanks to these outside experts.

From what I read in the existing risk analysis, I haven't seen that. I've seen that it was done with the project people and with their consultant [Westney], particularly for the strategic analysis. It said that it was done by [Westney] in consultation with their own client.

So when you have a risk analysis carried out by people of the project themselves and their own consultant, and not with participation of outside people, you are not sure at all of the validity of the results of these risk analysis. And I tell you if you put another group of people around the table, you probably have different results.

[Transcript, June 3, 2013, pp. 1625-1627]

[284] Further questions by the Board continued to focus on the risk register and evaluation:

MR. BOISSET: Well, what I could say is that we have not seen any quantification of the risks anywhere. What we have seen in this so-called tactical risk ranging sheets of the [Westney] Report is a cost item by cost item of what they call a risk range but, in fact, it's a cost item. Not -- we don't know which risk are involved.

...

So in fact, what they have, the tactical risk ranging sheet, it's a kind of an estimate for each individual item saying that, well, worst cost is plus or -- plus maybe 10 percent, 15 percent, whatever it is. And the worst -- the best cost is a better cost, lower cost. But it's not a risk analysis. A risk analysis is done risk by risk, not cost item by cost item.

And second thing, concerning the strategic risk, the strategic risk they have what they call total risk and then the unmitigated total risk and the mitigated risk. They say that they can certainly mitigate some of the risks and that in fact took lower figures thinking and expecting that they can do mitigated risk. This is, well, their opinion, but it's an opinion that was not, I would say, tested with an outside expert.

...

> MR. DEVEAU: So is your concern that based on the -- based on the various costs that they have included in their project cost, you're unable to ascertain whether all the risks in the risks register have been accounted for? Is that ultimately what the concern is?
>
> MR. WIEBE: That's a very fair presentation, yes.
>
> [Transcript, June 3, 2013, pp. 1629-1631]

[285] Enerco was also requested to identify, in an Undertaking, the type of information and the frequency of reporting that NSPML should provide to the Board during the construction period and during the 35 year term of the Maritime Link, if the Board was to approve the ML Project. In addition, if the Board was to retain independent experts to oversee NSPML, Enerco was asked to identify what type of reports the Board should expect to receive from those experts and how often those reports should be filed.

[286] Enerco provided their suggestions in response to Undertaking U-31. Those suggestions are more fully addressed in section 6.13 of this Decision.

6.4.4 Findings

[287] From an engineering and construction perspective, it is clear that the ML Project is a complex and challenging undertaking. This interconnection of the electrical grids of Nova Scotia and Newfoundland involves a lengthy subsea cable crossing in a rugged marine environment, a mix of relatively new HVDC and traditional AC technologies, and a significant range of individual components which must be carefully integrated to ensure that the electrical network continues to be fully functional and operates economically in a highly reliable manner.

[288] A review of the record shows that NSPML has devoted a considerable amount of attention to addressing the engineering, design, and risk management issues associated with the ML Project prior to filing its Application. However, as the review

process evolved, experts engaged on behalf of Board Counsel identified a number of concerns and gaps with respect to the work that had been done. As is evident from the C.V.'s of these experts, these individuals have significant international experience on these issues. Their analysis led to specific advice and recommendations which, for the most part, have been accepted and adopted by NSPML. Clearly, Board Counsel consultants have added significant value to the engineering and risk management aspects of the ML Project, and the Board was very impressed with their evidence.

[289] The Board has decided not to impose a long list of engineering conditions. NSPML should understand, however, that in determining the prudence of any future expenditure requests, NSPML will be acting at its peril if it ignores the competent and professional recommendations made by Board Counsel consultants.

[290] With the improvements that have been adopted, along with those that are still expected to be addressed during the bidding process, the Board now considers that the engineering and design details are sufficiently advanced for this project to proceed. The Board assumes NSPML will follow through with implementing the agreed upon improvements and that satisfactory engineering oversight will be put into place. This includes the provision of independent engineering reports.

[291] The Board will address the reporting requirements for engineering and technical matters in Section 6.13 of this Decision.

6.5 Should the capital and operating cost estimates for the ML Project be approved, including the capital structure and return-on-investment?

6.5.1 Capital Structure and Return on Equity

[292] NSPML requested, in its Application, approval of a debt to equity ratio of 70:30, with flexibility to vary to 65:35, in Phases 3 and 4 of the ML Project:

> While the capital structure for rate-setting purposes will be set at 30 percent equity, the company requests the ability to earn ROE on up to 35 percent actual equity during Phases 3 and 4. It is the unique nature of this single purpose entity, coupled with the provisions of the FLG that dictate a minimum level of equity (not an average level of equity) of 30 percent that gives rise to these challenges.
>
> [Application, Exhibit M-2, p. 81]

[293] NSPML requested approval of a rate of return on equity ("ROE") of 9.1% for 2011 through 2013, with a formula driven adjustment mechanism thereafter linked to the long-term A-rated Canadian utility bond yield. This would adjust the rate for construction years through to the realization of first commercial power.

[294] NSPML testified that the combination of low market interest rates compounded with a lower rate of financing expected as a result of the FLG, on 70% of the costs to finance this project "make this a tremendous time to finance this Project." It further explained:

> The Government of Canada's commitment to a FLG in support of the Project ensures a materially lower cost of debt since it serves as a guarantee to the lenders in the unlikely event that the Project is unable to repay its debt. The Federal Loan Guarantee would require that the Government of Canada fulfill any payment obligations of the Project to prevent a default on the guaranteed debt. ...
>
> [Application, Exhibit M-2, p. 85]

[295] NSPML indicated the benefit of the FLG is that it will contribute to reducing its cost of debt by obtaining the benefit of Canada's AAA rating. NSPML estimated the total benefit to be approximately $250 million over the life of the project, which represents a $100 million benefit in the NPV analysis.

[296] Evidence was introduced by NSPML's consultant Kathleen C. McShane, of Foster Associates, Inc., who supported the Applicant's request. Ms. McShane believes NSPML's request is conservative stating:

> ...The proposed 9.1% ROE for 2012 and 2013 is based on Nova Scotia Power Inc.'s (NSPI) 9.0%-9.2% ROEs negotiated and approved by the UARB for 2012-2014, rather than undertaking a comprehensive "from first principles" cost of equity study. In this context, NSPML's requested ROE is conservative, in my opinion. First, a "from first

> principles" cost of equity study would support a higher ROE for NSPI than has been allowed. Second, NSPML's proposed 30% common equity ratio is materially lower than NSPI's 37.5% ratemaking common equity ratio. NSPML's 30% common equity ratio compared to NSPI's common equity ratio, in isolation, supports a higher ROE for NSPML.
>
> [Application, Exhibit M-2, Appendix 4.02, p. 10]

[297] Board Counsel consultant, Dr. Lawrence Booth, accepted the current NSPI rate of 9.0% as the top of a reasonable ROE range, stating:

> This ROE is based on the settlement ROEs negotiated by NSPI in its 2012 and 2013/14 General Rate Applications and accepted by the Board of 9.2% for 2012 and 9.0% for 2013-2014. In 2012 I recommended an ROE for NSPI of 7.5% for 2013 and 8.5% for 2014, but felt the 8.50% was generously high. I therefore judge the settlement allowed ROE to be generous, that is, at the top of a reasonable range. ...
>
> [Booth, Exhibit M-39, p. 2]

[298] For the years 2012 and 2013 the CA's consultant, Dr. J. Randall Woolridge, recommended using an equity cost rate of 8.5%. He noted a number of drivers for a lower return recommendation than requested in the Application:

> There are several reasons why an 8.50% return on equity is appropriate for Maritime Link in this case. First, as shown on in Exhibit JRW-8, utilities are among the lowest risk industries according to *Value Line* as measured by beta. As such, this industry has the lowest cost of equity capital according to the CAPM. Second, as shown in Exhibit JRW-3, capital costs for Canadian utilities, as indicated by long-term bond yields, have declined to historically low levels. Third, the data evaluated in Exhibit JRW-3 suggest that capital costs in Canada are below those in the U.S. Furthermore, these interest rates have remained low for several years. In sum, the data and analysis presented in this case supports my equity cost recommendation of 8.50%. [Emphasis in original]
>
> [Woolridge, Exhibit M-52, p. 45]

[299] Further to the initial ROE, Ms. McShane supported the formula approach proposed by the Applicant that could see ROE increasing to 10.68% by the end of the construction period. This is also the ROE used to model the revenue requirement over the balance of the ML Project.

[300] Dr. Booth stated the formula proposed was inappropriate, indicating the Applicant's formula is not "backwardly compatible". During the recent years when interest rates were declining, utilities' ROE's did not see parallel declines. Dr. Booth

recommended the starting ROE, as determined by the Board, be adjusted by 50% of the change in the utility credit spread from 1.40% and 75% of the change in the forecast Long-Term Canada Bond yield above 3.8%.

6.5.1.1 Findings

[301] The Board notes the general acceptance by Intervenors of the capital structure proposed and finds it appropriate to take maximum advantage of the low cost of debt and benefits associated with the backing of the FLG. The Board approves the 70:30 debt to equity capital structure.

[302] The Board understands the flexibility requirements for purposes of complying with the covenants of the FLG, including a Debt Service Coverage Ratio. The Board notes the additional cost of permitting NSPML the ability to earn on a further five percent of equity, as opposed to debt, increases the cost of the project. To permit NSPML the flexibility it indicates is required, the Board finds it is appropriate to permit NSPML the flexibility to earn up to 35% actual equity during Phase 3, the construction phase. During Phase 4, the Board permits NSPML the flexibility to deviate throughout the year as required. However, during Phase 4, the operating phase, the Board does not approve any payout of earnings in excess of the approved ROE with a 30% equity thickness.

[303] NSPML is a single purpose entity created to take advantage of the FLG. As explained by Ms. Tower, the FLG requires a specific charge on assets in favour of Canada.

[304] NSPI, on the other hand, finances its debt instruments using a negative pledge clause. Therefore, a specific charge on assets would not be possible without

permission of other bondholders under the deeds of trust. The Board, therefore, accepts the need for a single purpose entity, NSPML. However, but for that requirement, NSPI would have been the entity to build the ML Project.

[305] In December of 2012 the Board confirmed NSPI's rate of return on common equity at 9.0%. There is no automatic adjustment formula.

[306] Had NSPI applied to build the ML Project the Board would not have revisited the ROE several months after having set it. In the circumstances, the Board finds the rate of 9.0% is appropriate for NSPML as well.

[307] NSPI does not have an automatic adjustment formula. There is no substantial regulatory lag in this province between the time NSPML might seek a hearing to adjust the ROE and the date of the hearing. If NSPML feels at some point, between now and 2017, the ROE needs to be adjusted it may apply and it will get a relatively speedy hearing from the Board. On the other hand, should the Board or Intervenors determine that the rate needs to be adjusted, the same process can be undertaken. The Board finds the inclusion of an automatic adjustment formula is not required in these circumstances.

[308] The ROE for NSPML will be 9.0% for ratemaking purposes within a range of 8.75% to 9.25%. NSPML will comply with NSPI's accounting policies in the same manner as NSPI, unless the Board approves otherwise.

6.5.2 Project Capital and Operating Costs Estimates

[309] The costs presented in order to determine whether the ML Project is the lowest long-term cost alternative included the up-front capital cost to be depreciated over 35 years, debt and equity financing costs, operating, maintenance and general expenses, sustaining capital and taxation.

[310] The construction costs have the most immediate impact on the ML Project as being the lowest long-term cost alternative. During the hearing the risk of cost overruns was explored. NSPML presented the estimated cost of the Maritime Link facilities of the ML Project under the P50 scenario as $1.4 billion. NSPML is responsible for 20% of those costs as well as 20% of the costs presented for LCP Phase 1, LIL and the Labrador transmission assets. The LCP Phase 1, LIL and Labrador transmission assets are all past Decision Gate 3 ("DG3") and, therefore, any potential cost overruns are the responsibility of Nalcor.

[311] Under the 20 for 20 Principle, this results in a P50 total cost of $1.52 billion. The following chart shows the cost under a 97% confidence level (P97) would increase to no more than $1.58 billion, which explains NSPML's requested variance of $60 million:

Total Maritime Link Project Estimated Capital Costs (before AFUDC)			
	ML cost **$1.4 billion** **[P50]**	**ML cost** **$1.5 billion** **[P90]**	**ML cost** **$1.7 billion** **[P97]**
LCP Phase 1 at DG3 (fixed)	$6.2	$6.2	$6.2
Maritime Link facilities range at DG2	$1.4	$1.5	$1.7
Total	$7.6	$7.7	$7.9
	x 20%	x 20%	x 20%
Twenty percent of total being Maritime Link Project capital costs to be included in NSPML rate base	$1.52	$1.54	$1.58

[Application, Exhibit M-2, Figure 4-2, p. 77]

[313] In addition to the capital cost, NSPML has requested approval of $230 million related to the Allowance for Funds Used During Construction ("AFUDC") that accumulates during the design and construction periods. The NPV to consider lowest long-term cost alternatives was presented in the financial model at Exhibit M-2, Appendix 4.01. This includes capital costs totaling $1.74 billion, representing the above $1.52 billion plus $230 million AFUDC. The $60 million variance requested is in addition to that considered for comparison of the alternatives.

[314] NSPML indicated that it had a high level of confidence in the costs of the ML Project presented to the Board and which were used to test the lowest long-term cost alternative:

> Mr. JANEGA: ...So because of the 80/20 cost sharing mechanism, and we have no expectation at this point, no issues that would indicate to us that we have cost problems on the project or that there is anything to indicate other than what we've presented to the Board for a best estimate for completing this, but if the project cost varied by 300 million, Nova Scotia would be exposed only to 60 million and 6.2 billion, the biggest portion of the project cost, is actually locked down; so it cannot change.
>
> It's a very substantial confidence level, let's call it, for the completion of the project as we have presented to the Board.
>
> ...
>
> MR. JANEGA: First and foremost in that, I don't want to leave any misunderstanding or impression that the cost control of this project is not our first and foremost concern. We have put together a project team. We have undertaken project management practices, project estimation, and invested millions of dollars at this point in the engineering and design of the Maritime Link well ahead of what is traditionally done.
>
> So going back to your comment of not doing the same thing that we've done in the past, there is a significant investment ahead of bringing this proposal to the Board which we believe is significantly different than projects that have been presented to the UARB.
>
> There is a much higher degree of confidence in the costs because of our approach to the marketing, contracting strategies that we've undertaken and the money that's been invested to ensure that we know where we're going to place the cable, the converter stations, interconnection studies.
>
> So it is not per se business as usual on this case. It is definitely being treated differently.
>
> [Transcript, May 30, 2013, pp. 933 and 937]

[315] NSPML assured the Board repeatedly throughout this hearing that it will manage the ML Project in the best interests of ratepayers.

[316] The capital costs are only a part of the cost of the ML Project over the 35 year term, as evidenced through a comparison of the $1.52 billion capital cost compared to the total costs identified in the NPV assessment. As the ML Project moves into commercial operation, NSPML will be solely responsible for cost of equity, cost of debt, repairs and maintenance, operating and general costs, taxation, and recurring capital investment. NSPML explained its expectation in respect of cost recovery in its Application:

> The Regulations clearly direct that once the Board has approved the Project and upon first commercial power, NSPML will be entitled to recover all Project Costs from NS Power. That process involves NSPML setting an assessment against NS Power for the recovery of such costs, and making a further application to the Board for approval of that assessment under the *Public Utilities Act.* In turn, NS Power will then be entitled to recover that approved assessment from time to time in respect of the Maritime Link Project through its rates.
>
> [Application, Exhibit M-2, pp. 90-91]

[317] Ms. Rubin clarified this should be read to entitle recovery of only prudent costs:

> MS. RUBIN: If the project is approved, and when the revenue requirement is filed, is there still an opportunity to look at the prudence of the revenue requirement?
>
> MS. TOWER: When we return to the Board specifically with the application for rates, which we expect to be in 2017, it will include prudently incurred capital costs as well as operating costs, debt costs and I think primarily -- primarily that.
>
> MS. RUBIN: So my question was, at the time the application is filed, is there still an opportunity to evaluate the prudence of the revenue requirement?
>
> MS. TOWER: I would say yes.
>
> MS. RUBIN: So when we read in the application that NSPL -- NSPML states it will be entitled to recover all project costs from ratepayers, we should read into that the word, "prudent"?
>
> MR. JANEGA: Yes.
>
> [Transcript, May 29, 2013, pp. 490-491]

[318] Costs are also imposed on NSPI as a result of compliance with the Commercial Agreements:

> NS Power may incur capital upgrade costs and when necessary re-dispatch its generating assets to allow Nalcor Surplus energy to be transmitted through Nova Scotia. NS Power has agreed to incur such costs and to collect transmission tariff revenue from Nalcor. To the extent that these costs exceed the transmission tariff revenues over each 5- year period of the term of the agreement beginning on the date of first commercial power, NS Power may seek recovery of this net cost relating to such 5-year period from NSPML. If this situation arises, NSPML will seek approval from the UARB to recover such costs from Nova Scotia customers via the assessment against NS Power as described below. Such costs are considered Project Costs for the purposes of this Application.
>
> [Application, Exhibit M-2, p. 90]

[319] Such costs have not been included in the NPV analysis as they are expected to be net neutral to ratepayers.

[320] To capture the 20 for 20 Principle ratio for the operating, general and maintenance costs, NSPML indicated there will be a true-up with Nalcor shortly after the ML Project is completed. A currently estimated $58 million true-up payment from Nalcor has been incorporated into the NPV prepared for purposes of comparing alternatives.

[321] Intervenors, including NSDOE, raised the concern of additional cost to ratepayers as a consequence of the relationship between NSPML and NSPI. NSDOE specifically recommended:

> NSPML/NSPI Transactions: Transactions between NSPI and NSPML should not come at a cost to Nova Scotia customers. NSPML and NSPI shall not earn an additional return on any transactions between companies: this includes, but is not limited to, billing processes relating to the arrangements relating to transmission through Nova Scotia.
>
> [NSDOE Closing Statement, p. 55]

6.5.2.1 Findings

[322] The ML Project is not a typical capital project. NSPML and the ML Project fall under new legislation that states once the project is approved the Applicant is entitled to

recover project costs through a rate, toll, charge or other compensation from NSPI in accordance with Section 8 of the *ML Regulations*.

[323] The Board interprets project costs as the funds required to cover a utility's expenditures for the purpose of serving ratepayers. The Board will assess entitlement to cost recovery in the same manner it does for any other utility it regulates.

[324] The Board approves the $1.52 billion cost outlined above and approximately $230 million related to AFUDC that accumulates during the construction period.

[325] The Board agrees with utilizing an estimate of AFUDC for ease of calculation; however, NSPML cannot capitalize any more than the actual carrying costs associated with the ML Project. The FLG is intended to flow a direct benefit to ratepayers, not Emera shareholders. Capital and financing costs should be trued up prior to any tax deductions being taken or earnings being calculated.

[326] The Board notes the statements of NSPML that additional costs imposed on NSPI, as a result of the ML Project and related Commercial Agreements, will be net neutral.

[327] With specific reference to the ASA in Appendix 8.01, the Board notes that formulas, methodologies, and processes for determining the 60-month true-up of transmission charges and the calculation of NSPI avoided costs associated with the NB backstop energy have not yet been agreed upon. The Board reserves the right to review these items at the appropriate time.

[328] The Board further notes NSPML's statements that no markup or earnings will be applied to the NB backstop energy put to NSPI and that no additional earnings will be applied to variances determined by the 60-month transmission true-up. NSPI also

stated that any credit determined by this true-up will be accrued with interest to the Nova Scotia ratepayers.

[329] The future operating and capital costs associated with the ML Project will require significant attention and scrutiny. The Board understands what has been put forward represents estimates only and, presumably, as many items may come in under budget as they will over budget.

[330] With respect to operating costs, the Board notes this is not a rate application and the Board has not been requested to, and does not make, a finding at this time with respect to operating and maintenance costs. The Board expects, however, that NSPML will manage the ML Project and the 35 years of costs associated with it prudently and rigorously.

[331] In line with NSDOE's recommendation, the Board finds there should be no additional costs to ratepayers as a result of related party transactions. Further, the Board finds there should be no additional costs to ratepayers as a result of timing differences or deferrals. Ensuring only the prudent costs of the ML Project investment and related expenses are passed on to NSPI and its ratepayers will be a particular focus of the Board in the future.

6.5.3 AFUDC

[332] AFUDC represents the financing costs the utility is permitted to capitalize. This covers the return on equity and cost of debt accumulated during the design and construction periods of a project. The Intervenors identified the risk that cost overruns and delays in the construction of the ML Project, as well as the completion of all elements of the Nalcor Transactions required to flow the expected energy, have on AFUDC.

[333] Morrison Park noted that Nova Scotia ratepayers are responsible for the risk of the physical completion of the Maritime Link, both in terms of the construction timeline and budgeting risk. It suggested that in such circumstances a mechanism could be put in place to more fairly apportion the risk:

> ...The 20 percent true-up (through cash or energy compensation) arrangement largely protects the ratepayer from exposure to cost changes that occur between a potential regulatory approval and the Decision Gate 3 confirmation of the cost of the ML, but the ratepayer remains solely responsible for any delay in COD [Commercial Operation Date], and solely responsible for cost overruns over that DG3 estimate, whether as a result of the ML itself or an independent delay in generation in MF and/or in transmission over the LIL, and other Newfoundland and Labrador transmission assets.
>
> The question arises as to whether or not it is fair for the ratepayer to be solely responsible for COD risk, and whether or not it would be unreasonable to apportion the cost of this risk among both the ratepayer and NSPML. In our opinion, there is scope for the Applicant to bear some measure of COD risk through a risk sharing mechanism. Such a mechanism could be structured in the form of an equity holdback, where NSPML's regulated return on equity (i.e. profits) are held back from the revenue requirement placed on the ratepayer. Such a holdback could start from a relatively modest base and escalate with time as appropriate. The idea would not be to transfer all COD risk to the Applicant, but to apportion the risk among both the Applicant and the ratepayer in a manner that reflects, as best it can, the interests of both.
>
> [Morrison Park, Exhibit M-46, p. 73]

[334] In questions from the Board at the hearing, Mr. Colaiacovo described how such a risk allocation mechanism might work for AFUDC:

> MR. COLAIACOVO: The Applicant has requested a rate to be applied to their investments during construction and then they foresee getting a ... "normal rate of return" when the project comes into service. That assumes that the project comes in on time and on budget.
>
> And as we identified in our report, there is a scenario where the Maritime Link is built on time and on budget; however, for whatever reason, an upstream portion of the overall project is not completed on time, whether it's the Muskrat Falls facility or transmission facilities running between Muskrat Falls and Newfoundland.
>
> In that scenario, the Maritime Link would be continuing to accumulate costs over time in the form of ...
>
> THE CHAIR: AFUDC.
>
> MR. COLAIACOVO: --- AFUDC and yet no electrons would be flowing. And this implies a considerable increase in net cost for the Nova Scotia ratepayer, which the Nova Scotia ratepayer is not in any position to manage. I mean, the Nova Scotia ratepayer has no tools with which to manage that risk.

> Emera would be in a much better position to have insight into that risk and potentially to manage that risk over time, and so what we suggested was creating additional incentive for them to manage that risk by a mechanism which affects both their AFUDC rate and potentially the rate of return on equity when the facility comes into service; a sharing of the impact of unforeseen delay.
>
> This doesn't go to the question of prudency so much as it does go to the incentive to manage risks that are out of the control of the ratepayer. In some contexts those costs are simply shared. Cost overruns are simply allowed into rate base, or not. In some -- or it could -- economically you could have the effect of simply reducing the return on equity to compensate for the fact that the project has been delayed.
>
> THE CHAIR: Can I take that in two parts? So, for example, what you're telling me is if that circumstance you described happened -- in other words, the link was built and ready to receive power and energy but it couldn't get it because some other portion of the project wasn't done -- we could, for example, say, no AFUDC would accumulate for that period?
>
> MR. COLAIACOVO: Yeah.
>
> [Transcript, June 6, 2013, pp. 2580-2582]

[335] Elsewhere in this Decision, the risks of cost overruns are addressed in terms of the approved cost of the ML Project and the $60 million variance approval sought by NSPML.

[336] However, the risks related to construction delays remain, as identified by Morrison Park. The Board accepts their evidence that these risks fall entirely on Nova Scotian ratepayers. This is an unreasonable allocation of risk for this project.

[337] Accordingly, the Board expects NSPML to prudently manage the ML Project construction timetable in a manner consistent with the construction schedule of the other components of the Nalcor Transactions (including the Muskrat Falls Generation Station, the LTA and the LIL), while remaining mindful of the total impact on costs in order to minimize costs to ratepayers.

[338] Further, the Board approves the accumulation of AFUDC up to and including December 31, 2017 or the in-service date of the Maritime Link, whichever is sooner. At that point, the Board will, applying the test of prudence, review the

management of the construction risks by NSPML. The Board will make a decision whether AFUDC will continue beyond that date based on how NSPML has managed the construction scheduling within the scope of the ML Project and the related phases in NL.

6.6 What variance, if any, should be established by the Board with respect to the approved cost of the ML Project?

[339] Section 6 of the *ML Regulations* provides:

> 6 (1) If requested by an applicant, the Review Board must establish a variance with respect to the approved cost of the Maritime Link Project.
>
> (2) The size of the variance must be set by the Review Board.
>
> (3) If at any time there are Project costs that exceed the variance established under this Section, an applicant must apply to have the excess costs approved by the Review Board in accordance with Section 8.

[340] NSPML's Application includes a variance of $60 million and requests Board approval of this amount as an approved project cost. The calculation of the variance amount is explained as follows:

> Figure 4-2 demonstrates the impact to Nova Scotia customers of cost changes as a result of the 20 for 20 Principle. Figure 4-2 illustrates that even if the DG3 capital cost estimate of the Maritime Link facilities is $1.7 billion (the current P97 estimate), the total Project capital cost would be $1.58 billion.
>
> As a result, NSPML also asks the Board to approve a variance of $60 million (reflecting the range between the requested $1.52 billion and the capital cost estimate of $1.58 billion) relating to the total estimated capital cost of the Maritime Link Project, to be included in the rate base of NSPML, as contemplated by Section 6 of the Regulations.
>
> [Application, Exhibit M-2, pp. 76]

[341] As noted in Figure 4-2 set out earlier in this Decision, the current estimate of the ML Project cost, based on a DG2 estimate, is $1.4 billion. When this amount is added to Nalcor's DG3 estimate of $6.2 billion for the remaining project cost and based on a 20/80 split (i.e., under the 20 for 20 Principle) between NSPML and Nalcor, NSPML's share of the ML Project cost is $1.52 billion, which is included in the

Application. It was noted that Nalcor's DG3 estimate of $6.2 billion is fixed regarding cost sharing between the two parties. Since the ML Project's current cost estimate is not based on DG3, any increase in cost is shared between the parties at the 20/80 ratio until NSPML fixes the ML Project cost at DG3. NSPML stated that the $60 million variance is based on the difference between its share of the total project cost of $7.6 billion and $7.9 billion, assuming the ML Project cost does not exceed $1.7 billion.

[342] During the hearing, Ms. Rubin questioned the accuracy of NSPML's cost estimates and NSPML responded:

> MR. RENDELL: So as you know, we've applied for 1.52 and a 60 million variance as outlined in the application. When we get to the October 1st DG3 estimate, it's our review that if that estimate and the full 20 per 20 calculation then yields a number somewhere between 1.52 and 1.58, that we then have the authority to proceed, that it would be considered prudent at the time, of course, pending the Board's ultimate decision.
>
> Any costs that may arise, then, subsequent to that would come into this cost overrun determination.
>
> [Transcript, June 3, 2013, pp. 1576-1577]

[343] The current cost estimate of the ML Project of $1.4 billion includes a contingency over and above the variance noted above. NSPML explained how this contingency is different from the $60 million variance requested by it in the Application:

> ...To summarize, the $1.4 billion deterministic capital cost estimate for the Maritime Link facilities is comprised of the following:

Base capital cost estimate	$1.17 billion
Escalation	$68 million
Contingency	$147 million
Total	$1.4 billion

> [Exhibit M-25, Response to IR-29(a)]

[344] Enerco, in its Responses to IRs, noted that NSPML included a contingency which is on the low side:

> $147 million is the contingency included in the deterministic cost estimate of $1.4 billion for the Maritime Link project (Ref RIR 29 page 2 of 2). This represents 12.5% of the bare capital cost estimate of $1.17 billion.

> In view of the concerns and uncertainties, as more specifically outlined in our second set of IRs, we believe that this a low percentage. We note also that this estimate was not validated by an independent cost consultant. A higher contingency will also increase the P90 and P97 cost estimates.
>
> [Exhibit M-57, Response to IR-1]

[345] The Province, in its Closing Statement, noted that:

> NSPML presented a range of capital costs for the Maritime Link from a P50 estimate of $1.4 billion to a P97 estimate of $1.7 billion. As a result of the 20 for 20 Principle, this produces a range of costs for which the Applicant is seeking approval in this proceeding. NSPML seeks the approval of Maritime Link Project costs of $1.52 billion and a variance of up to $1.58 billion. ...
>
> [NSDOE Closing Statement, p. 13]

[346] The Province submitted the following with respect to cost overruns:

> Construction Delay: Any/all delay costs incurred by NSPML during construction will be reviewed by the Board for prudency. Delay costs will not be passed to the NSPI ratepayer until a prudency review is conducted. Such a review may or may not involve an oral hearing.
>
> [NSDOE Closing Statement, p. 55]

[347] The LPRA, in its Final Arguments, expressed concern with respect to potential construction cost overruns:

> ... In fact, in addition to the estimated capital costs which are to be returned in increased rates, ratepayers are "potentially" liable for any cost overruns, time delays and potential breakages in the cable.
>
> [LPRA Final Arguments, p. 1]

[348] The LPRA further stated:

> There is a $60 million dollar variance now, the difference between $1.52 billion dollars and $1.58 billion dollars. The Board should cap the variance at the existing requested $60 million dollars.
>
> [LPRA Final Arguments, p. 5]

[349] The SBA, in its Closing Submission, also submitted that the variance should be capped:

> The Board to ensure there shall be no cost overruns over the $60M variance being applied for by the Applicant, and thus, any cost overruns would be capped at and included in that amount.

[SBA Closing Submission, p. 32]

[350] The CA, in its Closing Submission, expressed its concerns with respect to the cost overruns given the complex nature of the project:

> This is a project of considerable technical and construction challenge. While similar projects may have been successfully achieved in other parts of the world, there is no disputing that there are considerable challenges that will have to be overcome.
>
> The evidence of the applicant was once Decision Gate 3 point is reached, they will have a 97% probability of bringing the project in within anticipated costs.
>
> ...
>
> NSPML be held to its DG3 project cost estimates such that ratepayers do not bear all the risk associated with cost overruns.

[CA Closing Submission, pp. 21 and 24]

[351] The Industrial Group, in its Final Argument, recommended that the Board issue:

> ...a direction that NSPML is to manage the project within the envelope of money approved at its DG3, or in the alternative, impose a risk-sharing mechanism for COD risks such as an equity holdback as recommended by MPA.;

[Industrial Group Final Argument, p. 29]

[352] NSPML, in its Closing Brief, noted confidence in its ML Project cost estimates:

> The design development for the Maritime Link Project has been carried forward to the point that effective cost discovery has taken place for the key elements of the projects. The cost estimate for the Maritime Link is based on a significant amount of vendor and contractor pricing information, lending confidence to the component cost estimates, and risk assessments have been carried out to gauge the degree of any remaining uncertainty in each cost component. Appropriate contingency factors have been applied based on these assessed uncertainties, and NSPML is confident in the Project cost estimate based on DG2 pricing.

[NSPML Closing Brief, p. 41]

6.6.1 Findings

[353] The *ML Regulations* provide for approval of a variance to the approved cost of the ML Project. NSPML requested approval of a $60 million variance. This amount is based on the difference of NSPML's estimates of the ML Project cost

variation between $1.4 billion (P50) and $1.7 billion (P97). The difference of $300 million is to be shared between NSPML and Nalcor on a 20/80 basis, in accordance with the 20 for 20 Principle. It is noted that this cost sharing is only available until NSPML fixes its cost of the ML Project at DG3. Beyond that point, all additional costs are the 100% responsibility of NSPML.

[354] The Board also notes that Nalcor has already fixed its share of the ML Project cost of $6.2 billion (DG3), which is cost shared between the parties. Any additional Nalcor capital costs are the 100% responsibility of Nalcor.

[355] NSPML stated that it is reasonably confident, based on the engineering and vendor/contractors' input received to date, that the DG3 ML Project cost will be close to or less than $1.7 billion. However, if the costs do increase beyond $1.7 billion, NSPML indicated it will apply to the Board for approval of these additional costs in a timely manner.

[356] The Board has considered the evidence and recommendations from the Intervenors. It agrees that cost overruns are a serious concern for ratepayers, especially beyond DG3. The Board approves the variance of $60 million in prudently incurred costs as requested by NSPML.

[357] The Board expects NSPML to have strict controls during the design and construction phase of the ML Project to keep its costs within the approved envelope. While the Board will consider any additional request for cost overrun approval, the prudency test will be applied in rendering its Decision.

6.7 Will NSPI ratepayers receive <u>benefits</u> from the ML Project <u>commensurate with the risks and costs</u> they will bear if the ML Project is approved?

[358] This topic from the Issues List is dealt with in other sections of the Decision.

6.8 Do the ML Project and Nalcor Transactions comply with applicable provisions of NS Power's <u>Code of Conduct governing Affiliate Transactions</u>?

[359] NSPML, in its Application, acknowledged that certain portions of the Nalcor Transactions do not comply with NSPI's Code of Conduct governing affiliate transactions.

[360] NSPML noted that Section 3.1 of NSPI's affiliate Code of Conduct provides that "Emera, the parent company of NSPI, will create and maintain a corporate organizational structure which ensures that regulated and other utility services are provided solely by NSPI and no affiliate".

[361] Under the *ML Regulations*, NSPML is deemed to be a public utility under the *PUA*; hence the conflict.

[362] NSPML explained this further in response to NSUARB IR-12:

> NS Power is a party to the Agency and Service Agreement found at Appendix 8.01, which Agreement is a related transaction under the *Maritime Link Act* and thereby forms part of the Maritime Link Project. That Agreement is between two Nova Scotia public utilities, NS Power and NSPML. As above, a public utility which is affiliated with NS Power was not contemplated by the Affiliate Code. NSPML submits, and requests Board confirmation, that the Agreement is a binding and effective commitment by NS Power despite any potentially conflicting requirements of the Affiliate Code.
>
> [Exhibit M-11, NSUARB IR-12]

[363] If the ML Project proceeds, the Board grants the relief requested by NSPML with respect to the ASA. In addition, to the extent the Board has approved the Nalcor Transactions, the Board permits them to occur despite any provisions of the NSPI Code of Conduct.

[364] NSPML acknowledged, and the Board agrees, that there will have to be a specific code of conduct designed for NSPML. If the ML Project proceeds, the Board will initiate a process leading to the creation of a code of conduct for NSPML. In the meantime the NSPI Code of Conduct, with the relief granted above, continues to apply to transactions involving NSPI. Otherwise, to the extent possible, until a new Code is in place, NSPML will be guided by the terms and conditions of the NSPI Code of Conduct.

6.9 If the Board approves the ML Project, should it order any terms and conditions in its approval?

[365] Pursuant to s. 5(3) of the *ML Regulations*, in the event the Board approves the ML Project, it may order any terms and conditions it considers necessary.

[366] In other parts of this Decision, the Board has directed that various terms and conditions apply. These include the following:

1) That NSPML obtain from Nalcor the right to access Nalcor Market-priced Energy (consistent with the assumptions in the Application as noted in NSUARB IR-37 and Figure 4-4) when needed to economically serve NSPI and its ratepayers; or provide some other arrangement to ensure access to Market-priced Energy.

2) That accumulation of AFUDC is approved up to and including December 31, 2017 or the in-service date of the Maritime Link, whichever is sooner. At that point, the Board will, applying the test of prudence, review the management of the construction risks by NSPML. The Board will make a decision whether AFUDC will continue beyond that date based on how NSPML has managed the construction scheduling within the scope of the project in its entirety.

3) That there should be no additional costs as a result of related party transactions, timing differences or deferrals.

4) That no markup or earnings will be applied to the NB backstop energy put to NSPI and that no additional earnings will be applied to variances determined by the 60-month transmission true-up. Any credit determined by this true-up will be accrued with interest to the Nova Scotia ratepayers.

5) As discussed later in Section 6.13, that NSPML (including NSPI where appropriate) will provide reports to the Board no later than June 15th and December 15th of each year, unless otherwise directed by the Board. Before the Board finalizes its reporting requirements, NSPML will meet with Board staff to work out the details of such requirements on the basis of the directives in this Decision. Board staff are to report back to the Board for approval of the reporting requirements by October 15, 2013. The Board directs NSPML to provide Board staff with its full cooperation in meeting this timeline.

6) NSPML will be guided by the terms and conditions of NSPI's Code of Conduct (except as noted in this Decision) and accounting policies until NSPML applies to the Board for approval of its own policies.

6.10 Do the *ML Act* and *Regulations* authorize or require the Board to <u>approve the Nalcor Transactions and related transactions</u>? and

6.11 Are the ML Project and Nalcor Transactions supported by a <u>reasonable and comprehensive set of commercial agreements</u>?

[367] The *ML Act* authorizes the Board to approve the ML Project. The *Act* defines the ML Project as:

> 2 (c) "Maritime Link Project" means the design, construction, operation and maintenance of the Maritime Link, together with the related transactions involving the delivery of energy, the provision of transmission services over the Maritime Link and the enabling of transmission service through the Province, as set out in a term sheet between Emera Incorporated and Nalcor Energy dated November 18, 2010;

[368] The *ML Regulations* provide that the Board must approve the ML Project if the conditions of s. 5(1) are met.

[369] The ML Project is defined in part by the various Commercial Agreements described earlier in this Decision. Subject to the imposition of conditions by the Board and, in particular, the Market-priced Energy condition, the Board has generally taken the approach that it should not attempt to fine tune those Agreements.

[370] The only evidence on the fairness of the Nalcor Transactions, as represented by the Commercial Agreements, was provided by Morrison Park who opined that:

> ...MPA is of the opinion that the Project is fair, from a financial point of view, to ratepayers of Nova Scotia.
>
> [Morrison Park, Exhibit M-46, p. 10]

[371] Morrison Park included in their prefiled evidence a section which outlined the distribution of risks, costs and benefits among the parties being Nalcor, Emera, Nova Scotia ratepayers, Canada and NL ratepayers, which is summarized in a chart which appears at page 63 and 64 of their prefiled evidence. Subject to Morrison Park's concern about construction risk, which is dealt with elsewhere in this Decision, it stated as follows:

> As between Nalcor, Emera and Nova Scotia ratepayers, MPA does not see anything in our review of the ML which gives rise to concerns with respect to commercial fairness.
>
> Nalcor is contributing the greatest capital to the project, and taking the most significant financial risks, including merchant risk on a portion of the output of the Muskrat Falls facility. Emera is contributing significant capital, but does not appear to be likely to earn returns that are above market expectations for regulated investments. Nova Scotia

ratepayers are accepting normal risks associated with any new regulated asset, and in our view at a price that is consistent with the other main option available.

From a strategic perspective, all three stakeholders are making gains. Nalcor, which again is contributing the most and taking the most risk, is gaining a very significant strategic benefit with respect to its future dealings with Quebec on transmission-related issues, and it receives an immediate alternate route to the limited transmission capacity it currently enjoys. Emera, again contributing significant capital and accepting financial risk, is supporting its long term business plan, and bolstering its position in the market as a major player in the utilities sector. Nova Scotia ratepayers, while the risk that the ultimate price of the ML in comparison to other options will not be known except in hindsight, will benefit immediately upon construction by a fundamentally changed position in the electricity market, and an immediate improvement in its system reliability.

[Morrison Park, Exhibit M-46, pp. 69-70]

[372] One remaining concern the Board has is the calculation of Supplemental Energy. Since capital costs will be incurred relating to facilities with an estimated life of 50 years, but NSPML will only own them for 35 years, compensation has been calculated such that NSPML will receive additional energy in the first five years of the ML Project of approximately 240,000 MWh per year. The basis for that calculation is set out in Schedule 4 of the ECA. Morrison Park supported NSPML's calculation.

[373] Levitan, on behalf of the CA, in particular criticized the calculation and produced for the Board what they described as a more appropriate calculation:

...A more appropriate method of achieving the stated goal of compensating for the loss of 15 years of on-peak energy delivery would be to determine the amount of energy valued at off-peak rate prices in the first 5 years that would have the same present value as the forgone deliveries in years 36-50 valued at the 7x16 prices expected to prevail in those years after adjustment for the present value of the O&M expense incurred in those years.

[Levitan, Exhibit M-45, pp. 54-55]

[374] In Levitan's view, the amount of winter energy required in each of the first five years to equate the present value of net cost over the 35 year term to that of the 50 year term should be 398,969 MWh per year.

[375] NSPML did not provide a compelling defence of their own calculation in light of the Levitan criticism. Clearly this concerns the Board but, having regard to

earlier comments about accepting, for the most part, the Nalcor Transactions as negotiated, NSPML's negotiation of Supplemental Energy is part of the ML Project as a whole and has been weighed by the Board as part of its entire review.

[376] With respect to the Commercial Agreements they have one fatal flaw, described elsewhere in this Decision, and that is the failure to have any contractually enforceable covenant to access Market-priced Energy. That concern is subject to a condition outlined earlier.

[377] Otherwise, the Board is satisfied that the Commercial Agreements constitute a reasonable and comprehensive set of commercial agreements.

[378] Accordingly, subject to the conditions imposed in this Decision, and in particular the Market-priced Energy condition, the Board approves the design, construction, operation and maintenance of the ML Project together with related transactions involving the delivery of energy, the provision of transmission services over the Maritime Link and the enabling of transmission service through the province as described in the Commercial Agreements.

[379] The Board considers it has discharged its obligation under the *ML Act* with respect to the approval herein. So, despite the requests of NSPML in Section 10 of its Reply Brief and in the Application, the Board does not intend to explore such issues as to whether infrastructure in Labrador is subject to the *Utility and Review Board Act*.

6.12 Does the *ML Act* authorize or require the Board to approve the transfer of the Maritime Link to Nalcor, and the sale of the Woodbine Upgrades to NSPI, following a period of 35 years after energy is first delivered to NSPML?

[380] The Nalcor Transactions require NSPML to convey the Maritime Link to Nalcor at the end of the original term of 35 years for $1. Also, upgrades at the Woodbine Substation are to be conveyed to NSPI at the same time.

[381] The Board notes that, as part of the ML Project, an extension to the Woodbine Substation is to be constructed to facilitate the entry of power into the Substation. In NSUARB IR-32(c), NSPML indicated that the transfer to Nalcor comprises the infrastructure "up to the 200 kv dc line termination points at the Woodbine substation." It is proposed that this infrastructure will be conveyed to Nalcor at the end of the 35 year term.

[382] The remaining upgrades related to Woodbine are proposed to be conveyed to NSPI, and are described in CA/SBA IR-171 and IR-271.

[383] As part of its Application, NSPML requested Board approval of the sale of the Maritime Link to Nalcor and the sale of the Woodbine upgrades to NSPI after the completion of the 35 year term, including the approval of any terms necessary to perfect the transfers.

6.12.1 Findings

[384] As noted in the Application, NSPML is a utility within the meaning of the *PUA*. Accordingly, under s. 62 of the *PUA*, the Board's approval is required before NSPML can sell, assign or transfer all or part of its utility undertaking. NSPML requested the Board approve these sales in advance so as to provide "greater certainty", given the unique circumstances of the ML Project.

[385] Although not explicitly stated in the Application, the Board assumes (by virtue of the Commercial Agreements) that NSPI and Nalcor consent to these transfers.

[386] The transfer of the Maritime Link assets to Nalcor at the end of the 35 year term is but one component of a complex commercial arrangement. The transfer is accounted for in the economic analysis provided to the Board in support of the ML Project's approval. The Board also notes the transfer means that Nalcor will assume responsibility for the costs of operating and maintaining the Maritime Link assets, thereby relieving NSPML and ultimately NSPI ratepayers of those costs.

[387] Having regard to the foregoing considerations, the Board is prepared to approve the transfer of the Maritime Link assets to Nalcor and the transfer of the Woodbine upgrades to NSPI, subject to the tax and cost assumptions presented.

[388] Comparing the Application and NSPML's response to NSUARB IR-32(c), the Board noted an inconsistency with respect to the assets being transferred. The Board directs NSPML to provide a description of the assets being transferred prior to issuance of the Board's Order.

6.13 What schedule should the Board order for project reports, if any, on the progress of the ML Project?

[389] Section 7 of the *ML Regulations* provides:

> **Project report**
> 7 (1) An applicant must file a project report on the Maritime Link Project containing the details required by subsection (2) with the Review Board:
>
> (a) on or before December 31, 2013; or
>
> (b) on or before another date the Review Board orders, as it considers necessary as a result of the progress of the Maritime Link Project.
>
> (2) A project report must set out all the following for the Maritime Link Project:
>
> (a) detailed engineering and design information;
>
> (b) updated and current cost estimates and actuals;

(c) any material changes to any of the information submitted to the Review Board under Section 5.

[390] The Application seeks the following order from the Board:

vi) Requiring NSMPL to file a project report no later than December 31, 2013, which shall inform the UARB of the results of the 20 for 20 Principle calculation, and which shall seek approval for any true-up payment or energy adjustment that results from the application of the 20 for 20 Principle;

[Application, Exhibit M-2, p. 30]

[391] NSPML noted that it will prepare an annual work program and budget for approval by the Joint Development Committee:

In each year of the project, NSPML will prepare an annual work program and budget for the development activities of the upcoming year. These will require the approval of the Joint Development Committee to help the parties effectively manage cost risks, opportunities and stay aligned on project plans. A formal Change Management process will govern all changes to scope, schedule, resources and associated cost impacts. When the project team has developed the project scope and engineering to a level consistent with AACE Class 2, which will include market based pricing for the major components and approval of environmental review, the project scope and budget will be presented for construction approval at Decision Gate 3.

[Application, Exhibit M-2, p. 94]

[392] The approval process is further elaborated in Appendix 2.02 of the Application:

3.4 Powers of the JDC-ML

(a) Authority of JDC-ML - Without derogating from the authority granted by other provisions of this Agreement, the JDC-ML shall:

(i) receive, consider and, if appropriate, as determined by the JDC-ML, Approve, recommendations of the Project Manager and the Project Director with respect to the Development Activities regarding the ML Project, including with respect to:

(A) approval of the Project Schedule and the initial Project Execution Plan and any subsequent changes in the Project Execution Plan and the Project Schedule;

(B) approval of AFEs and Budgets and each Annual Work Program and Budget;

(C) approval of any changes to the Pre-Sanction AFE;

(D) approval of any changes to the then current AFE to authorize additional expenditures in excess of $1,000,000, and approval of all changes to the then current AFE after additional expenditures previously approved, if any, in the aggregate exceed one percent of the total expenditure authorized by the Master AFE;

(E) all Decision Gate submissions as part of the Decision Gate process, acknowledging that final Decision Gate decisions rest with the responsible Gatekeepers;

[Application, Exhibit M-2, Appendix 2.02, p. 31]

[393] During the hearing, the Board canvassed NSPML and other parties about potential reports which may be useful for the Board's consideration, during the construction period and during the 35 year term of the Commercial Agreements.

[394] NSPML noted during the hearing that its DG3 costs are expected to be finalized in October 2013 and the Board will receive this information.

[395] NSPML, in response to Undertaking U-22, suggested the following reporting schedule:

> NSPML proposes a semi-annual progress report to the UARB after December 31, 2013. The report could contain such items as;
>
> - forecast cost as compared to the UARB approved project costs and variance as well as the progress of a Level 1 Schedule (showing the major activities of the project and their status)
> - variance explanation for specific cost items above a materiality threshold
> - changes to any major contracting strategies or execution plans which could affect project costs (outside the variance) or schedule
> - status of the highest level risks as identified and the mitigation plan for each
> - in-service date projection and first commercial power
>
> The report would be filed no later than June 15th and December 15th each year.
>
> Additionally, NSPML proposes that any reports provided to the Federal Government, including such details as engineering or financial detail, also be provided to the UARB.
>
> [Exhibit M-110, Undertaking U-22]

[396] Enerco undertook to provide its recommendation for items which the Board may include in its Decision for NSPML reports. Enerco provided its response in Undertaking U-31, which is summarized below:

A. Design and Construction Phase

i. Provide Quarterly reports on the project schedule status, including explanation of variances, starting July 1, 2013.

ii. Provide status report, including key risks and potential consequences for each of the following activities: commercial, engineering, subsea cable, DC converter stations, transmission lines, and compounds.

iii. Semi-annual report starting July 1, 2013 on the detailed project schedule similar to NSPML's attachment to Enerco RIR-8.

B. Provide updates on construction cost on a quarterly basis including projected costs to the end of the construction period, and any variance from the NSPML Application, starting July 1, 2013.

C. Provide revised schedule for the design and construction methods for the undersea cable:

i. Report from the independent consultant on the detailed design, construction planning and methods of the selected EPC Contractor, no later than May 31, 2014;

ii. Provide independent expert review prior to the construction of the HDD work for cable protection and shore landings, no later than March 31, 2014;

iii. Provide independent expert review prior to cable installation of the proposed monitoring by NSPML for cable laying, jointing, protection and terminations, no later than January 15, 2016.

D. Operation and maintenance period of 35 years:

i. Provide a long-term cable maintenance plan and a plan for emergency cable repair procedures, six months prior to cable commissioning.

[397] The CA, in its Closing Submission, and the Industrial Group, in its Final Argument, recommended that:

> The Board adopt the recommendations of Enerco (Undertaking 31) relating to project oversight.
>
> [CA Closing Submission, p. 24]

[398] NSPML, in its Closing Brief, agreed with the Board's oversight on the ML Project, especially during the design and construction phase. To this end, it added that NSPML plans to file the following reports with the Board:

- NSPML will file a project report pursuant to section 7(1) of the Regulations during Q4 2013, which will advise the Board of the DG3 determination and 20 for 20 calculations. The project report will seek approval for any true-up payment or energy adjustment that may result from the application of the 20 for 20 Principle.
- NSPML will file a revenue requirement and rate application in advance of commissioning of the Maritime Link Project, as required by Section 8 of the Regulations.
- NSPML will file semi-annual progress reports with the UARB, no later than June 15 and December 15 of each year during construction.
- NSPML will provide the Board with any reports that are prepared and provided to the Federal Government regarding the Maritime Link, including such details as engineering or financial detail.
- Independent engineering reports will be provided to the Board when completed.

[NSPML Closing Brief, pp. 56-57]

[399] NSPML further stated:

> NSPML has reviewed the Enerco proposals in its response to Undertaking U-31. While many of these suggestions for oversight and reporting have merit, NSPML suggests that the timing of reporting may be better aligned once NSPML better understands the proposals suggested by Enerco. NSPML will work promptly and diligently with Board staff and advisors to develop the details with respect to these reporting and oversight procedures. NSPML shares the Board's objective to have transparency and oversight to the Board's satisfaction. NSPML will be pleased to work with Board staff on an expedited basis following approval in order to better develop the reporting requirements.

[NSPML Closing Brief, p. 57]

[400] The Province, in its Closing Statement, made a recommendation for the Board's oversight of the ML Project:

> Independent Engineer: an independent engineer will be appointed to review the total engineering scheme of the cable, consisting of the design, manufacture, installation, the laying of protection and reparability. The independent engineer will report directly to the Board and produce the reports suggested by Enerco in Exhibit M-110, Undertaking U-31. To avoid duplication, an independent engineer already involved in the project may satisfy this obligation.

[NSDOE Closing Statement, p. 55]

6.13.1 Findings

[401] The *ML Regulations* provide for a filing by NSPML by December 31, 2013 along with such other reports the Board may require.

[402] NSPML is required to file a report by the end of 2013 to provide DG3 cost estimates, including confirmation of the 20 for 20 Principle calculations.

[403] The Intervenors and Board Counsel consultants have suggested some reporting protocols and regular filing of written reports by NSPML.

[404] The CA and Industrial Group supported Enerco's recommendations as noted in their Closing Submission.

[405] Enerco, in Undertaking U-31, recommended filing of various reports by NSPML during the design and construction phase of the ML Project. The Board has reviewed Enerco's recommendations and generally agrees that given the size of the ML Project and that the final engineering design and tender awards are not completed, it is appropriate for NSPML to provide regular reports to the Board.

[406] NSPML, in its Closing Brief, also agreed with Enerco's recommendations. However, NSPML suggested that before the Board finalizes its reporting requirements, it would like to meet with Board staff to better understand the information being requested. The Board agrees this would be an efficient process. The information noted above by NSPML at pages 56-57 of its Closing Brief could form the basis for the discussion. The Board directs that it receive reports no later than June 15th and December 15th of each year, unless otherwise directed by the Board. As noted earlier, the Board believes independent engineering reports will be critical to keeping the Board informed. The Board expects this consultation process to be carried out expeditiously and Board staff are to report back to the Board for approval of the reporting requirements by October 15, 2013.

6.14 Does the OATT need to be amended to incorporate or otherwise accommodate the provisions of the NSTUA?

[407] NSPI has a Board approved Open Access Transmission Tariff ("OATT") which permits power and energy to be transported or wheeled on the NSPI transmission system by third parties for the fees outlined in the OATT.

[408] When the Board determined the Issues List for this hearing it had assumed that Nalcor would be a customer under the OATT. Through the course of the hearing it became clear that Nalcor would not be a tariff customer as the obligation to transport power and energy will be NSPI's. NSPI will be the customer of the System Operator for the transmission of Nalcor Surplus Energy. In these circumstances the OATT does not need to be amended.

[409] It will be NSPI's obligation to accept power from Nalcor for wheeling through the province to the Nova Scotia – New Brunswick border. These obligations are outlined in the NSTUA.

[410] The maximum amount of energy that may be scheduled by Nalcor is the lesser of:

- The Maritime Link design capacity less the transmission capacity on the Maritime Link required by Nalcor to deliver the NS Block and any other energy Nalcor has agreed to sell to NSPI; and
- The expected transmission capacity requirements set forth in Section 2 of the NSTUA.

[411] Unlike an OATT customer, Nalcor will not pay a reservation charge to ensure that its power and energy is wheeled on the transmission system. Nalcor will only pay the applicable tariff charges in respect of transmission facilitation service when

NSPI is transporting Nalcor Surplus Energy. What appears to be proposed is that Nalcor will pay for non-firm service but NSPI, at its expense, will ensure it gets firm service. NSPI gave repeated assurances, however, that ratepayers would be kept whole in this arrangement.

[412] In future, if Nalcor wishes to transmit power and energy over and above the Nalcor Surplus Energy, as defined in the Nalcor Transactions, it would be required to comply with the OATT in the same manner as any other customer.

[413] NSPI indicated that it also expects to incur approximately $31.5 million to upgrade its transmission system to accommodate this Nalcor power and energy. Generation fleet re-dispatch requirements are estimated to be in the $6 to $8 million range each year. However, NSPI anticipates that re-dispatch costs will reduce as coal plants retire.

[414] NSPI indicated that, based on the projections of Nalcor Surplus Energy, it expects that the transmission fees paid by Nalcor will offset the associated capital expenditures and re-dispatch costs and any anticipated maintenance costs resulting from Nalcor Surplus Energy flowing through Nova Scotia. This presumes, however, that Nalcor Surplus Energy flows on the Maritime Link.

[415] In the event that the revenue from the Nalcor transmission fees does not fully recover these expenditures, there is a curious process to bill those cost overruns to NSPML which are billed back to NSPI. The Board sees this as an accounting entry which has no particular purpose.

[416] Mr. Sidebottom, on behalf of NSPI, argued that structuring the transaction this way enhances NSPI's ability to obtain Market-priced Energy from Nalcor. He

argued that if Nalcor were a standard OATT customer it would have paid for a transmission path through Nova Scotia which would then become a sunk cost. He argued that if Nalcor had paid for the transmission path it would have less incentive to sell power and energy to NSPI at market prices. He argued that charging Nalcor for transmission capacity only when it uses the system incents Nalcor to sell to NSPI at market prices and avoid those transmission costs (in addition to line losses). This assumption, of course, is predicated on the very important condition that Market-priced Energy does, in fact, flow through the Maritime Link.

[417] While at first blush it appears unusual that Nalcor would be relieved of the reservation charges in the OATT, the Board does see the logic in NSPI's argument that by structuring the transaction this way it should incent Nalcor to sell Market-priced Energy in this province.

[418] Another concern raised by the Industrial Group, and in questioning from the Board, related to the provisions of Section 2.1(d)(i) of the NSTUA which provides that interruptible customers will be interrupted prior to curtailment of Nalcor's transmission through Nova Scotia. Mr. Sidebottom repeatedly assured the Board that, as a result of the negotiation of the forgivable events clause, he and Rob Bennett (then President of NSPI) negotiated, this would not be the case:

> MR. SIDEBOTTOM: ...An example would be the dispatchability of the basic block, the fact that the forgivable events inside the transmission path are very important to avoiding exposure for customers to interruptions on the flow through.
>
> [Transcript, May 29, 2013, p. 476]
>
> ...
>
> MS. RUBIN: Okay. Now, that clause speaks to curtailments in the -- curtailments of energy and it provides that interruptible customers will be interrupted prior to any curtailment of the Nova Scotia nominated transmission quantity.
>
> And by interruptible customers there, those include members of the Industrial Group?

MR. SIDEBOTTOM: That is correct.

MS. RUBIN: Okay. What analysis has Nova Scotia Power done in relation to its interruptible customers to evaluate the increased risk of interruption due to transmission of the Nalcor energy?

MR. SIDEBOTTOM: Actually, this was one of the clauses that I spoke about earlier that Mr. Bennett and myself considered. And what we did was ensure that, under the definition of something called forgivable events, that all of the situations we could actually foresee on the transmission system that would potentially create a situation that would enact that clause were effectively forgiven.

And we wanted to make sure that we wouldn't affect our customers on that front, as we knew that this would be a concern. And so we did, in fact, create that safeguard through the force majeure language and the forgivable events language.

[Transcript, May 29, 2013, pp. 550-551]

...

MR. SIDEBOTTOM: ... And what that means is that under those situations there isn't a requirement for our customers to be making way for the Nalcor energy, if that makes sense.

[Transcript, May 31, 2013, p. 1167]

[419] Section 2.7 of the NSTUA indicates that Emera (NSPI) is not responsible, or in default of the NSTUA, if there is interruption in the wheeling service occasioned by a forgivable event.

[420] The Board is prepared to accept the assurance from NSPI, through Mr. Sidebottom, that curtailment of interruptible customers will, in the normal course, not happen to accommodate transmission of Nalcor Surplus Energy. The Board will carefully monitor any interruptions to ensure NSPI lives up to this undertaking from both an operational and financial perspective.

[421] As part of the ML Project and subject to system reliability concerns, NSPI is obliged to purchase energy from Nalcor if NSPML is unable to provide a transmission path through New Brunswick. The obligation is actually in the ASA. The purchase will take place at a cost equivalent to the avoided cost of backing down NSPI generation.

The Board was assured these arrangements are structured in a manner to be cost neutral to NSPI's ratepayers and any other costs associated with transmission obligations to NSPML would not be passed on to Nova Scotia customers.

[422] As part of the Nalcor Transactions, the Board approves the transmission arrangements pursuant to the NSTUA and the put arrangement discussed above pursuant to the ASA.

6.15 How does the provision for delivery of energy other than the NS Block affect the distribution of benefits, costs and risks among the parties involved in the ML Project, the Nalcor Transactions, and related transactions, including <u>whether Nova Scotia ratepayers are subsidizing transactions</u>?

[423] This topic from the Issues List is dealt with in other sections of the Decision.

6.16 Will the ML Project result in a requirement for increased reserves to meet the <u>reliability standards and criteria</u>?

6.16.1 Operating Reserves

[424] If the Maritime Link is constructed with a bipole capacity rating of 500 MW, or monopole rating of 250 MW, Intervenors questioned whether this would result in additional operating reserve requirements, and thereby, additional costs to ratepayers. The premise for this concern was that the proposed capacity available from Nalcor would be significantly greater than NSPI's current single largest contingency (i.e., 172 MW at Point Aconi), which would therefore require a higher level of operating reserve.

[425] The NSPML Reply Evidence addressed the issue of the NB-NS Reserve Sharing Agreement ("RSA") relative to a 300 MW import. Essentially, the New Brunswick System Operator ("NBSO") coordinates the RSA for the Maritimes Area,

which has the obligation to comply with the North American Electric Reliability Corporation's ("NERC") Disturbance Control Standard ("DCS").

[426] An explanation of the RSA as it relates to the 10-minute synchronous (spinning) reserve requirement is provided on pages 17 and 18 of Appendix A in the NSPML Reply Evidence. Calculations show that the largest contingency for which reserve sharing applies is 550 MW. Based on the load-ratio share formula, under current conditions, NSPI's portion of the Maritimes Area 10-minute spinning reserve is 33 MW. With the Maritime Link in place and a 300 MW import contingency, that spinning reserve share would increase by 16 MW to 49 MW. The explanation further noted that this increase of 16 MW could be accommodated most of the time through incremental dispatch of NSPI's committed generators at little increased cost.

[427] The Board understands that this explanation was accepted by parties who initially raised this concern.

6.16.2 Reliability/Availability Targets

[428] During the proceeding, various questions regarding system reliability were raised. Those questions were focused on reliability of the overall system, reliability of the HVDC overhead transmission lines with VSC technology, and reliability of the submarine cables.

[429] In response to CCI IR-5, NSPML stated that the availability target for the Maritime Link is 95-97%, which will be validated during the final design and review of supplier performance characteristics. NSPML also noted that this availability was "based upon experienced reliability levels of typical overhead high voltage transmission systems, converter availability, no projected major cable failures and includes all routine substation and converter maintenance...".

[430] During the course of this proceeding, the reliability concerns raised by Dr. Hingorani regarding the HVDC overhead transmission lines and VSC technology were acknowledged by NSPML and the Board understands that measures will be taken to resolve those concerns.

[431] Similarly, reliability and availability concerns raised by CCI regarding the submarine cable were also acknowledged by NSPML and the Board understands that measures will be taken to address those concerns during the bid evaluation and selection process as well as during the construction phase.

[432] During the hearing, NSPML noted that these design enhancements will improve the Maritime Link availability target to a range of 96-99.8%. In response to Undertaking U-18, NSPML stated that the target availability for the LIL, LTA, and Muskrat Falls Generation Station is 98-99.9% and confirmed the target for the Maritime Link.

[433] When considering reliability, it is understood that as a member of the Northeast Power Coordinating Council ("NPCC"), NSPI must comply with the reliability criteria established by the NERC for the bulk power system. The Board understands that these criteria are currently being satisfied and that completion of the Maritime Link interconnection will further enhance the reliability of the Nova Scotia transmission system. This point was noted in the evidence filed by Board Counsel consultant, Mr. McMaster:

> It is a common understanding in the electric utility industry that interties enhance system reliability provided that they are properly planned and integrated. The benefits come through such things as reserve sharing, increased ability to withstand system contingencies and in the event of a major interruption, assistance in system restoration.
>
> ...

> A second intertie, in this case the ML, will enhance system reliability. The ML will provide the added benefit of geographic diversity over a reinforced/new intertie with NB. This diversity will help mitigate the risk from such things as ice storms or other severe weather. It would also enable Nova Scotia to receive support/assistance from two separate electric systems rather than one, as at present.
>
> [Exhibit M-47, pp.4-5]

6.17 Are there <u>contractual obligations, including water rights issues</u>, that would serve as an impediment to NSPI obtaining the NS Block?

[434] With reference to any contractual rights arising from the Nalcor Transactions, any such issues have been dealt with earlier in this Decision.

[435] With respect to water rights issues specifically, this concern was included in the Board's Final Issues List to canvass any potential risk arising from water flow on the Churchill River that might impact power generation at Muskrat Falls.

[436] The Board canvassed this concern in NSUARB IR-70, which questioned NSPML whether there would be any water right or water flow issues that could serve as an impediment to NSPI obtaining the NS Block. NSPML replied that there were not.

[437] NSMPL confirmed that there were no risks to ratepayers from the non-delivery of energy by reason of any legal claim respecting the flow of water, or arising from the reduction of water flow itself on the Churchill River:

> The contractual arrangements between Emera and Nalcor do not allow for non-delivery of energy. If the energy is not delivered, Nalcor is liable to pay compensation damages to Emera. If the non-delivery is as a result of Government Action, the Government of Newfoundland and Labrador has guaranteed payment by Nalcor the compensation damages. Risks relating to Muskrat Falls are borne by Nalcor.
>
> [Exhibit M-11, NSUARB IR-70]

[438] NSPML was questioned further in an IR about what potential costs exist and how the Commercial Agreements protect ratepayers from reduced water flow at Muskrat Falls. Reduced water flow was described as being due to contractual water rights issues, climate change, or other reasons. NSPML responded:

> Lack of precipitation is expressly not a Force Majeure event and is therefore not a Forgivable Event under the Energy and Capacity Agreement. The NS Block will not be Curtailed for that reason.
>
> [Exhibit M-11, NSUARB IR-76 (h)]

[439] There were no material references to water rights issues in any prefiled evidence. Additionally, no Intervenor raised the issue in their closing submissions. On the basis of the evidence before it, the Board finds it unnecessary to further canvass the issue.

7.0 COSTS

[440] Both the EAC and LPRA asked for costs in support of their participation in the proceeding.

[441] Section 6 of the Board's *Costs Rules* provides:

> 6 (2) The Board may consider awarding costs against a utility to non-profit, public interest intervenors with limited financial resources who
>
> (a) have a substantial interest in the proceeding;
>
> (b) will be affected by the proceeding;
>
> (c) participate in the hearing in a responsible way; and
>
> (d) contribute to a better understanding of the issues by the Board.

7.1 Ecology Action Centre

[442] While the Board has awarded costs to the EAC in past proceedings when the Board felt its participation met the test outlined in the *Rules*, EAC's participation in this proceeding was very limited. No evidence was filed by the EAC and there was very limited cross-examination of one witness panel. Final Argument was also very limited. In the circumstances the Board declines to award costs to the EAC.

7.2 Lower Power Rates Alliance of Nova Scotia

[443] The LPRA has submitted a cost request in the amount of $205,729.

[444] The bulk of those costs appear to be time entries for Archie Stewart, who participated in the hearing, and then further time entries for Todd MacDonald, BSM Energy and Craig MacDonald, who the Board assumes are parties related to LPRA.

[445] Mr. Stewart, at one point in the proceeding, described himself as the hardest working volunteer. That seems inconsistent with a claim of $76,050 for his time participating in the hearing.

[446] While the Board notes LPRA claims it is a not-for-profit society in Nova Scotia dedicated to lowering electrical power rates for all ratepayers, the Board is unaware of any mandate, statutory or otherwise, having been provided to LPRA by ratepayers or on their behalf. This contrasts, for example, with the CA and SBA, both of whom are provided for in the *PUA* and are appointed by the Board.

[447] Having said that, the evidence of Mr. Blain and Mr. McCullough did add to the hearing record. As in the past, the Board suggests that LPRA and NSPML see if they can agree on a cost amount, failing which the Board will make a determination. They should be guided, however, by the Board's view that the only costs the Board would be inclined to order are a contribution to the costs for the expert evidence of Mr. Blain and Mr. McCullough and out-of-pocket expenses related to attendance at the hearing, translation and any other reasonable out-of-pocket expenses.

[448] LPRA should understand that costs of regulatory proceedings are a cost of doing business by a utility which are eventually, under the *PUA*, recovered from ratepayers.

[449] With respect to future proceedings, the mandate LPRA has taken upon itself is one which the Board views as largely served by the CA and SBA and, therefore,

LPRA should not assume that costs would be available in, for example, upcoming NSPI rate cases or other proceedings.

8.0 *MARITIME LINK ACT*

[450] In discussions with Government during the drafting of the *ML Regulations* the Board recommended that the *ML Regulations* include a provision giving the Board all of the powers contained in the *PUA*. The Board understood that Government agreed with this, but preferred to amend the *ML Act* to enact such a provision. The Board had understood that the *ML Act* would be amended; however, that has not happened so far. If the ML Project proceeds, the Board remains of the view that the *ML Act* should be amended to contain such a provision.

9.0 SUMMARY OF BOARD FINDINGS

[451] Under s. 5(1)(a) of the *Maritime Link Cost Recovery Process Regulations*, the Board must approve the ML Project if the "project represents the lowest long-term cost alternative for electricity for ratepayers in the Province".

[452] Taking into account all of the evidence, the Board finds, on the balance of probabilities, that the ML Project (with the Market-priced Energy factored in) represents the lowest long-term cost alternative for electricity for ratepayers in Nova Scotia. In the absence of Market-priced Energy, the ML Project is not the lowest long-term cost alternative.

[453] While the Board finds that the ML Project is the lowest long-term cost alternative, it is not on an overwhelming basis. There are various scenarios, within a range of reasonable assumptions that perform almost on an equivalent basis, or even better in a few cases, than the ML Project. Nevertheless, the Board concludes that over the broadest range of assumptions for the ML Project it is slightly more robust than the

various other alternatives. On this basis, the ML Project does edge out other alternatives and is deserving of approval under s. 5(1) of the *ML Regulations*.

[454] However, the Board remains very concerned with the availability of Market-priced Energy under the ML Project, as presently proposed by NSPML.

[455] The fundamental assumption which underpins the Application is that NS customers will enjoy a blended rate for electricity which is comprised of a weighted average of the costs reflecting the NS Block and the projected amounts and prices for Market-priced Energy over the 35 year term.

[456] Until 2041, when Newfoundland and Labrador's Churchill Falls arrangement with Hydro Quebec comes to a conclusion, the availability of Market-priced Energy from Nalcor is an issue of "substantial uncertainty". This leaves NSPI in the unenviable position of having no contractual certainty of obtaining Market-priced Energy from Nalcor. However, NSPML/Emera have accepted no risk as a result of that contractual uncertainty. As they have structured the deal, that risk falls entirely to Nova Scotia ratepayers.

[457] The Board concludes that the availability of Market-priced Energy is crucial to the viability of the ML Project proposal as against the other alternatives. More importantly, the Board finds that without some enforceable covenant about the availability of the Market-priced Energy, the ML Project does not represent the lowest long-term cost alternative for electricity for ratepayers in Nova Scotia.

[458] It is the Board's obligation to protect the interests of Nova Scotian ratepayers. More specifically, the Board is required in this proceeding to apply the test under s. 5(1) of the *ML Regulations*. The Board has considered how it should address

this significant risk to the viability of the ML Project as against the other alternatives. It could, under the *ML Regulations*, simply reject the Application, but that would not be the responsible result and would not be a productive outcome of the regulatory process.

[459] Accordingly, the Board directs as a condition to its approval of the ML Project that NSPML obtain from Nalcor the right to access Nalcor Market-priced Energy (consistent with the assumptions in the Application as noted in NSUARB IR-37 and Figure 4-4) when needed to economically serve NSPI and its ratepayers; or provide some other arrangement to ensure access to Market-priced Energy.

[460] In the Board's opinion, such a condition should not create any practical difficulty because it would simply codify what NSPML asserts is the effect of the arrangement in any case. It would also confirm what NSPML already states is Nalcor's view of their future relationship.

[461] This is a simple remedy to the fundamental risk underlying NSPML's Application for approval of the ML Project. If no such condition was imposed, the Board would fail in its regulatory oversight by approving an application that could potentially be commercially disadvantageous to NS ratepayers.

DATED at Halifax, Nova Scotia, this 22nd day of July, 2013.

Peter W. Gurnham

Roland A. Deveau

Kulvinder S. Dhillon

Appendix A - List of Intervenors

Alton Natural Gas Storage LP	David Birket, President Jan van Egteren
Canadian Wind Energy Association (CanWEA)	Shawna Eason, Atlantic Regional Director Tom Levy, Manager, Technical & Utility Affairs
Consumer Advocate (CA)	John Merrick, Q.C. William Mahody, LL.B.
Ecology Action Centre (EAC)	Catherine Abreu, Regional Energy Coordinator Jamie Thomson
Efficiency Nova Scotia Corporation (ENSC)	Sean Foreman, LL.B.
Grand Riverkeeper Labrador Inc.	Roberta Frampton Benefiel Vice President
Heritage Gas Ltd. (HGL)	Michael Johnston Manager, Regulatory Affairs
<u>Industrial Group</u> Canadian Salt Co. Ltd. CKF Inc. Crown Fibre Tube Inc. Halifax Grain Elevator Ltd. Imperial Oil Ltd. Lafarge Canada Inc. Maritime Paper Products Ltd. Michelin North America (Canada) Inc. Minas Basin Pulp & Power Co. Ltd. Oxford Frozen Foods Ltd. Sifto Canada Corp. Nustar Terminals Canada Partnership	Nancy Rubin, Q.C. Robert Grant, Q.C. Maggie Stewart, LL.B.
Lower Power Rates Alliance of Nova Scotia (LPRA)	Archie Stewart
Municipal Electric Utilities of Nova Scotia Co-operative (MEUNSC)	Don Regan Albert Dominie
Nova Scotia Liberal Caucus	The Honourable Stephen McNeil Andrew Younger, MLA
Nova Scotia PC Caucus	The Honourable Jamie Baillie

Nova Scotia Power Inc. (NSPI)	Terence Dalgleish, Q.C. David Landrigan, LL.B., General Manager, Regulatory Affairs Nicole Godbout, LL.B., Regulatory Counsel
Nunatukavut Community Council Inc. (NCC)	Todd Russell, President
Port Hawkesbury Paper LP	Shawn Lewis Bill Stewart
Province of Nova Scotia NS Department Of Energy (NS DOE) NS Environment (NSE)	Stephen T. McGrath, LL.B. Chris Spencer Michelle Miller
Sierra Club Atlantic	Gretchen Fitzgerald, Director
Small Business Advocate (SBA)	E.A. Nelson Blackburn, Q.C. Paul Miller, LL.B.
The Shoreline Journal	Maurice Rees, Publisher
Larry Hughes	
Peter Allen	
Patrick J. Bates	
Brendan Haley	
Dr. V. Ismet Ugursal	

Appendix B - List of Public Speakers

Name	Organization
1. Barry Alexander	
2. William Black	
3. Barbara Pike	Maritimes Energy Association
4. Luciano Lisi	Cape Breton Explorations
5. Fred Morley	Greater Halifax Partnership
6. John Herron	Atlantica Centre for Energy
7. Dr. Barbara Clow	Canadian Research Institute for the Advancement of Women
8. Gail Baikie	FemNorthNet
9. Roberta Frampton Benefiel	Grand Riverkeeper Labrador Inc.
10. Keith MacDonald	Cape Breton Partnership

Appendix C - Letters of Comment

	Name	Organization
1.	Charles Jess	
2.	Richard Plett	
3.	Valerie Payn	Halifax Chamber of Commerce
4.	Norm MacFarlane	
5.	Chris Atwood	Nova Scotia Chamber of Commerce
6.	Willem Stokdijk	
7.	Peter MacLellan	Digby and Area Board of Trade
8.	Billy Joe MacLean	Town of Port Hawkesbury
9.	Roxanne R. Fairweather	Innovatia Inc.
10.	Dr. David Wheeler	
11.	William Black	
12.	Barry Alexander	
13.	Kenneth Torrence	

2

SUPPLEMENTAL DECISION **2013 NSUARB 242**
M05419

NOVA SCOTIA UTILITY AND REVIEW BOARD

IN THE MATTER OF THE MARITIME LINK ACT

- and -

IN THE MATTER OF AN APPLICATION by **NSP MARITIME LINK INCORPORATED** for approval of the Maritime Link Project

BEFORE: Peter W. Gurnham, Q.C., Chair
Roland A. Deveau, Q.C., Vice-Chair

APPLICANT: **NSP MARITIME LINK INCORPORATED**
James H. Smellie, LL.B.
René Gallant, LL.B.

INTERVENORS: **PATRICK J. BATES**
on his own behalf

CONSUMER ADVOCATE
John P. Merrick, Q.C.
William L. Mahody, LL.B.

INDUSTRIAL GROUP
Nancy Rubin, Q.C.
Maggie Stewart, LL.B.

LOWER POWER RATES ALLIANCE OF NOVA SCOTIA
Craig McDonald

NOVA SCOTIA POWER INCORPORATED
David Landrigan, LL.B.
Nicole Godbout, LL.B.

PC CAUCUS OFFICE
Chris d'Entremont, M.L.A.

PORT HAWKESBURY PAPER LP
Bevan A. Lock

Document: 220498

PROVINCE OF NOVA SCOTIA
(Department of Energy)
Stephen T. McGrath, LL.B.
Ryan Brothers, LL.B.

SMALL BUSINESS ADVOCATE
E.A. Nelson Blackburn, Q.C.
Paul B. Miller, LL.B.

BOARD COUNSEL:	S. Bruce Outhouse, Q.C. Richard J. Melanson, LL.B.
HEARING DATE(S):	November 14 and 15, 2013
FINAL SUBMISSIONS:	November 18, 2013
DECISION DATE:	**November 29, 2013**
DECISION:	**Subject to the representations and clarifications provided by NSPI and NSPML, all conditions in the Board's Maritime Link Decision dated July 22, 2013, are satisfied: see the summary starting at paragraph [126]**

TABLE OF CONTENTS

1.0 INTRODUCTION

[1] This is a Supplemental Decision of the Nova Scotia Utility and Review Board (the "Board") respecting an application of NSP Maritime Link Incorporated ("NSPML" or the "Applicant") filed on January 28, 2013, under the *Maritime Link Act*, S.N.S. 2012, c. 9 (the "*ML Act*") and the *Maritime Link Cost Recovery Process Regulations* (N.S. Reg. 189/2012) (the "*ML Regulations*") for approval of the Maritime Link Project and the Nalcor Transactions (the "Application").

[2] In a Decision dated July 22, 2013 [2013 NSUARB 154] ("ML Decision"), the Board concluded, applying the test under s. 5(1)(a) of the *ML Regulations*, that the Maritime Link Project (with Market-priced Energy factored in) represents the lowest long-term cost alternative for electricity for ratepayers in Nova Scotia. However, in the absence of Market-priced Energy, the Board concluded that the ML Project is not the lowest long-term cost alternative. Accordingly, the Board directed:

> ...as a condition to its approval of the ML Project that NSPML obtain from Nalcor the right to access Nalcor Market-priced Energy (consistent with the assumptions in the Application as noted in NSUARB IR-37 and Figure 4-4) when needed to economically serve NSPI and its ratepayers; or provide some other arrangement to ensure access to Market-priced Energy.
>
> [ML Decision, para. 228]

[3] In addition to the above condition respecting Market-priced Energy, the Board also directed that various other terms and conditions apply:

> ...
>
> 2) That accumulation of AFUDC is approved up to and including December 31, 2017 or the in-service date of the Maritime Link, whichever is sooner. At that point, the Board will, applying the test of prudence, review the management of the construction risks by NSPML. The Board will make a decision whether AFUDC will continue beyond that date based on how NSPML has managed the construction scheduling within the scope of the project in its entirety.
>
> 3) That there should be no additional costs as a result of related party transactions, timing differences or deferrals.

> 4) That no markup or earnings will be applied to the NB backstop energy put to NSPI and that no additional earnings will be applied to variances determined by the 60-month transmission true-up. Any credit determined by this true-up will be accrued with interest to the Nova Scotia ratepayers.
>
> 5) As discussed later in Section 6.13, that NSPML (including NSPI where appropriate) will provide reports to the Board no later than June 15th and December 15th of each year, unless otherwise directed by the Board. Before the Board finalizes its reporting requirements, NSPML will meet with Board staff to work out the details of such requirements on the basis of the directives in this Decision. Board staff are to report back to the Board for approval of the reporting requirements by October 15, 2013. The Board directs NSPML to provide Board staff with its full cooperation in meeting this timeline.
>
> 6) NSPML will be guided by the terms and conditions of NSPI's Code of Conduct (except as noted in this Decision) and accounting policies until NSPML applies to the Board for approval of its own policies.
>
> [ML Decision, para. 366]

[4] On October 21, 2013, NSPML filed its Compliance Filing with a view to satisfying the above conditions outlined in the ML Decision.

[5] The Compliance Filing included an 18 page Energy Access Agreement ("EAA") executed on October 20, 2013. Emera, Nalcor and NSPI negotiated for almost three months to conclude the EAA, which was filed with the intention to satisfy the principal condition with respect to NSPI's access to Nalcor Market-priced Energy.

[6] In its Decision, the Board indicated as follows:

> [230] The Board will make itself available on an expedited schedule to review commercially reasonable terms submitted by NSPML and Nalcor and for comments by the Intervenors.
>
> [ML Decision, para. 230]

[7] Upon receiving the Compliance Filing, the Board established a timeline which began with a Technical Conference, leading to a hearing, including oral argument or written submissions. The timeline, as subsequently adjusted in response to Intervenor requests, was as follows:

Technical Conference	October 28, 2013
Filing of Intervenor and Board Counsel Evidence	November 7, 2013
Hearing Dates	November 14 and 15, 2013
Oral Argument	November 18, 2013

[8] The hearing was held at the Board's Offices at Halifax, Nova Scotia. The Board notes that, for the purposes of this hearing, the proceedings at the Technical Conference were transcribed and the transcript was filed in evidence as an exhibit.

[9] Various witness panels testified at the hearing. The witness panel for NSPML and NSPI consisted of Nancy Tower, Chief Executive Officer of Emera Newfoundland and Labrador; Rick Janega, President of Emera Newfoundland and Labrador; Wayne O'Connor, NSPI's Executive Vice-President of Operations; and Mark Sidebottom, NSPI's Vice President, Generation and Delivery. The witness panel for the Consumer Advocate ("CA") and the Small Business Advocate ("SBA") was comprised of Paul Chernick, the President of Resource Insight, Inc., and Seth Parker, Vice President and Principal of Levitan & Associates, Inc., while Philip Raphals, Executive Director of the Helios Centre, testified on behalf of the Lower Power Rates Alliance. Finally, Board Counsel called Pelino Colaiacovo and Brent Walker of MPA Morrison Park Advisors Inc. ("Morrison Park") to testify as a panel.

[10] The Board also received letters of comment from members of the public which were filed as part of the record.

[11] A comprehensive review of the *ML Act* and the *ML Regulations* is contained in the Board's ML Decision.

2.0 ML DECISION – BOARD FINDINGS

[12] In addition to the above terms and conditions imposed by the Board in the ML Decision, it also made a number of findings which provided the context for its

conclusion respecting access to Market-priced Energy. For the purposes of the analysis which follows, the Board considers it helpful to set out those findings:

> [106] On balance, the Board believes that NSPML's "Low Load" forecast, which most closely aligns with NSPI's current load forecast, is a more realistic scenario than NSPML's "Base Load" forecast. The Board accepts the evidence of Synapse, Levitan and Resource Insight that NSPML's "Base Load" forecast is more in the nature of a high load forecast. However, as was pointed out, a number of factors could impact load in a way which could cause it to be higher. It is prudent for NSPI to have flexibility in their load forecasts.
>
> ...
>
> [156] Except with respect to the issue of Market-priced Energy, the Board is satisfied that the range of sensitivities tested by NSPML in its Strategist modeling represents a prudent approach to evaluating energy alternatives for the province and its ratepayers. The Board is generally satisfied with the reasonableness of most of the various assumptions made by NSPML in the composition of the ML Project alternative (except, as noted earlier in this Decision, the concerns referred to by Synapse, Levitan and other parties about load and the Study Period used in the analysis).
>
> ...
>
> [159] One of the important potential benefits of the ML Project is that it could provide access to Market-priced Energy. In fact, it is the access to this energy which causes the ML Project (assuming the Market-priced Energy is available) to be the lowest long-term cost alternative for electricity for Nova Scotian ratepayers.
>
> ...
>
> [163] The Board observes that the presence of the Maritime Link could continue to benefit Nova Scotia even after the expiration of the 35 year term of the Commercial Agreements, because Nova Scotia will still be positioned to access competitive energy markets.
>
> ...
>
> [170] Taking into account all of the evidence, the Board finds, on the balance of probabilities, that the ML Project (with the Market-priced Energy factored in) represents the lowest long-term cost alternative for electricity for ratepayers in Nova Scotia. In the absence of Market-priced Energy, the ML Project is not the lowest long-term cost alternative for electricity for ratepayers in Nova Scotia.
>
> [171] While the Board finds that the ML Project is the lowest long-term cost alternative, it is not on an overwhelming basis. Based on the evidence presented by Synapse, which the Board accepts, there are various scenarios, within a range of reasonable assumptions, that perform almost on an equivalent basis, or even better in a few cases, than the ML Project. On this point, the Board refers to Synapse's Strategist runs of the Indigenous Wind "Low Load" scenario, as well as the Hybrid option formulated in Undertaking U-41.
>
> [172] The Board does not interpret the test in the ML Regulations in a way whereby the ML Project fails because one or two scenarios indicate it could fail. Instead, over a broad range of assumptions, the ML Project passes the test because on a balance of

probabilities it remained the lowest long-term cost alternative if Market-priced Energy is factored in.

[173] The Board concludes that over the broadest range of Strategist runs for the ML Project it is slightly more robust than the various other alternative runs conducted by Synapse. On this basis, the ML Project does edge out other alternatives and is deserving of approval under s. 5(1) of the *ML Regulations*.

...

[200] While legitimate questions remain about the availability of Market-priced Energy from Nalcor over the first 24 years of the Maritime Link, the evidence clearly shows that there should be no shortage of Market-priced Energy when the Churchill Falls arrangement with Hydro Quebec comes to a conclusion in 2041. The Churchill Falls Generating Station has a capacity of 5,428 MW, which over the past five years has averaged approximately 33 TWh per year (Nalcor's 65.8% share of the Churchill Falls Corporation would therefore yield approximately 22 TWh of energy supply in 2041).

[201] However, until 2041 arrives, there is, as Morrison Park described it, "substantial uncertainty" about the availability of a supply of Market-priced Energy from Nalcor for Nova Scotia.

...

[208] In reviewing the importance of the availability of Market-priced Energy to the Application, the Board referred back to Figure 4-4 of the Application, which is outlined earlier in this Decision. The fundamental assumption which underpins the Application is that NS customers will enjoy a blended rate for electricity which is comprised of a weighted average of the costs reflecting the NS Block and the projected amounts and prices for Market-priced Energy over the 35 year term.

[209] In response to NSUARB IR-37, NSPML provided a breakdown of the annual energy quantities associated with the NS Block supplied over the Maritime Link and the purchase of Market-priced Energy, as depicted on Figure 4-4. The Market-priced Energy consists of projected imports over the NB/NS intertie and from Newfoundland and Labrador, with about 70% of Market-priced Energy sourced from Nalcor, via the Maritime Link, over the course of the 35 year term.

...

[223] Taking all of the above into consideration, the Board concludes that the availability of Market-priced Energy is crucial to the viability of the ML Project proposal as against the other alternatives. Without the Market-priced Energy, the ML Project is clearly not "robust". More importantly, the Board finds that without some enforceable covenant about the availability of the Market-priced Energy, the ML Project does not represent the lowest long-term cost alternative for electricity for ratepayers in Nova Scotia.

[224] The Board has considered how it should address this significant risk to the viability of the ML Project as against the other alternatives. It could, under the *ML Regulations*, simply reject the Application, but that would not be the responsible result and would not be a productive outcome of the regulatory process.

[225] In the Board's opinion, the price of future Market-priced Energy is not the real concern, as alleged by Intervenors. The Board understands and accepts that it may be advantageous to make opportunity purchases of Market-priced Energy, when it is to

NSPI's benefit to do so. In that regard, the Board's primary concern is not exposing a relatively small portion of NSPI's energy portfolio to market prices, rather the concern is that the advantageous opportunity to purchase cannot take place, if there is no Market-priced Energy to buy.

[226] The Board will impose a condition relative to the availability of Market-priced Energy over the 35 year term. In the Board's opinion, such a condition should not create any practical difficulty because it would simply codify what NSPML asserts is the effect of the arrangement in any case. It would also confirm what NSPML already states is Nalcor's view of their future relationship.

[227] This is a simple remedy to the fundamental risk underlying NSPML's Application for approval of the ML Project. If no such condition was imposed, the Board would fail in its regulatory oversight by approving an application that could potentially be commercially disadvantageous to NS ratepayers.

[228] Accordingly, the Board directs as a condition to its approval of the ML Project that NSPML obtain from Nalcor the right to access Nalcor Market-priced Energy (consistent with the assumptions in the Application as noted in NSUARB IR-37 and Figure 4-4) when needed to economically serve NSPI and its ratepayers; or provide some other arrangement to ensure access to Market-priced Energy.

[229] Further, the Board expects that any such confirmation of Market-priced Energy will come at no additional cost to ratepayers, because this assurance was described by NSPML during the hearing as representing the intention of both Nalcor and Emera in the deal presented in the Application. In effect, the Board is simply attempting to get legal certainty over what NSPML has already assured Nova Scotians will be the result of the deal. Moreover, the imposition of any additional cost could jeopardize the ML Project as the lowest long-term cost alternative and, in the end, would not be the deal proposed in the Application.

[230] The Board will make itself available on an expedited schedule to review commercially reasonable terms submitted by NSPML and Nalcor and for comments by the Intervenors.

[231] The Board notes that NSPI will be required to act prudently in the acquisition of Market-priced Energy as it would with all other fuel related decisions. Decisions related to the purchase of Market-priced Energy will be subject to the provisions of NSPI's Fuel Adjustment Mechanism and the oversight that occurs under that mechanism. [Emphasis added]

3.0 ENERGY ACCESS AGREEMENT

[13] The critical terms of the EAA are summarized succinctly by Morrison Park:

- Nalcor commits to make available to NSPI 1.2 TWh of non-firm energy per year on average over the course of the Agreement, which is expected to last approximately 24 years between 2017 and 2041;
- Annual availability of energy could be up to 1.8 TWh, but could be as low as 0 TWh in any given Contract Year (September 1 – August 31) depending on the Nalcor Forecast of Available Energy;

- Nalcor commits to provide NSPI with a rolling 24-month forecast of expected available non-firm energy, on a monthly basis;
- Once per year, in the month of June, NSPI has the option to issue a solicitation for non-firm energy for the following Contract Year, and Nalcor commits to bid into that solicitation, based on Nalcor's May 31 Forecast, up to a maximum of 1.8 TWh;
- In NSPI's solicitation, Nalcor may bid any price for its energy, up to and including the MassHub price, or the higher price of any alternative liquid market opportunity available to Nalcor;
- If there is an extended dry period or some other system difficulty, and it appears that there will be insufficient energy available for export from Newfoundland and Labrador to meet Nalcor's commitment to NSPI over the term of the Agreement, then Nalcor will declare that there will be a "Variance". In this event, Emera shall be responsible for the first 300 GWh per annum of any shortfall, and Nalcor shall be responsible for the remainder;
- In the case of a Variance, if Emera chooses to satisfy its obligation to offer up to 300 GWh of energy through the construction of new intermittent energy facilities in Nova Scotia (including wind, solar and tidal power facilities), then Nalcor will offer up to 100 MW of balancing services under a fixed price contract;
- Even in the event that Nalcor satisfies the commitment to provide at least 1.2 TWh per Contract Year on average before the term of the Agreement is completed (by providing more than 1.2 TWh per year in the early years, for example), Nalcor must still offer its Forecast Available Energy in NSPI's annual solicitation throughout the full term of the Agreement.

[Morrison Park, Exhibit M-140, pp. 3-4]

[14] As noted by Morrison Park, there is an inter-play between Nalcor's commitment to provide 1.2 TWh of non-firm energy per year (on average) and its ability to offer up to 1.8 TWh per year:

> Note that if the Agreement lasts 24 years, then in order to achieve at least 1.2 TWh per year on average, Nalcor will be required to make available at least a cumulative total of 28.8 TWh over that time period. If the Maritime Link is a year late, and hence the Agreement lasts only 23 years, then the cumulative total requirement would be 27.6 TWh. This calculation is relevant because Nalcor may offer more or less than 1.2 TWh in any given year, up to a maximum of 1.8 TWh. So, for example, if 1.8 TWh were offered for the first 16 years, then it would not matter how much was offered in the remaining years, because 28.8 TWh would have already been offered.

[Morrison Park, Exhibit M-140, p. 3, Footnote 5]

[15] Nalcor's contractual commitment under the EAA is to provide, on average, 1.2 TWh of energy per year. The term of the EAA extends to 2041. However, even if it satisfies its commitment prior to 2041 (i.e., by providing up to 1.8 TWh of energy in one

or more years, which would result in providing the cumulative amount of 28.8 TWh before 2041), Nalcor remains obligated to provide its forecast and bid commitment throughout the term of the agreement until 2041.

[16] On this point, René Gallant, Vice-President, Legal and Regulatory Affairs with Emera Newfoundland and Labrador, noted during the Technical Conference that even though Nalcor's commitment to provide, on average, 1.2 TWh per year may be satisfied prior to 2041, there remains an obligation on Nalcor to bid, annually, its forecast of up to 1.8 TWh into NSPI's solicitation throughout the entire term of the EAA:

> The 1.8-terawatt hour forecast and bid commitment is in every year of the term, regardless of when the 1.2 average commitment is met. And, so, if it's met early, that means that all the rest of those years are going to add additional energy into the equation for Nova Scotia Power customers, and in fact, increase the value of the commitment beyond what is represented by Undertaking 3, and Figure 4-4.
>
> [Technical Conference, Exhibit M-137, p. 48]

[17] At the Technical Conference, Mr. Gallant described Nalcor's ability to seek other markets if its bid was not accepted by NSPI. However, he added that it was open to Nalcor to bid again in response to another solicitation by NSPI later in the same year:

> Well, the initial commitment to make energy available, and then to make the forecast of available energy known, and then bid that forecast amount at a capped price is the commitment that creates the market opportunities for Nova Scotia Power and its customers.
>
> But, as a reasonable commercial entity, if Nalcor's energy, at that point, is not taken up by Nova Scotia Power, either because they don't need it, or they don't accept it at the price at which its bid, then Nalcor has to have the flexibility to go back to market, or find another customer for that energy at that time. And if they still have energy available when Nova Scotia Power next goes out to the market, then, like any other player in the market, they can bid in.
>
> [Technical Conference, Exhibit M-137, p. 78]

4.0 ISSUES

[18] The Board considers that the issues that must be addressed in this Decision are as follows:

1. Does the EAA satisfy the condition with respect to access to Market-priced Energy?
2. What should be the reporting requirements for NSPML during the course of the ML Project?
3. Does the Compliance Filing satisfactorily address the other conditions imposed by the Board?
4. Should the ML Project be approved?

5.0 ANALYSIS AND FINDINGS

5.1 Does the EAA Satisfy the Condition with Respect to Access to Market-priced Energy?

5.1.1 Benefits

[19] As noted in the passages from the ML Decision quoted above, the Board was not concerned about exposing a portion of NSPI's load to market-based pricing. However, the Board was concerned that without some contractual guarantees there may be no surplus energy available in the market to purchase.

[20] Both Morrison Park and NSPI highlighted a number of benefits of the EAA which, in their view, helped satisfy the Board's concerns.

[21] Indeed, Morrison Park indicated they do not believe it is a correct characterization of the EAA to say it is an energy supply agreement. They said it is, in reality, a contract that guarantees access by NSPI to the market, noting that NSPI may not in any particular year actually issue an RFP or accept any bids for Nalcor Market-priced Energy, if that is not the economic choice. However, the EAA provides NSPI with the benefit of precluding Nalcor from contracting power to third parties on a long term basis as Nalcor must forecast and bid into annual NSPI solicitations. That provision applies in each year of the term of the EAA irrespective of the fact that Nalcor may have satisfied the average 1.2 TWh contractual obligation. Morrison Park described that

contractual commitment as a series of 24 one-way options in favour of NSPI that it can exercise for 24 different consecutive years in the future. Morrison Park noted that NSPI has not taken on any additional commitments in the EAA.

[22] Mr. Walker of Morrison Park explained this further:

> What this agreement does is it forces Nalcor contractually to be in the market, and in our minds that's what satisfies the condition, because you have now created the market, whereas before we had a concern that the market might not get created because they're going to do a long-term deal with some other party in the marketplace. And now Nalcor is contractually committed to have their power in the market every year, and that's what makes the realization of these projections that we've been talking about possible, whereas before it was only a theoretical possibility.
>
> [Transcript, p. 3059]

[23] Morrison Park noted that another beneficial provision of the EAA is that Nalcor must disclose its expectations about power availability through the 24 month forecast. Mr. Walker noted that when you are transacting with a counterparty, knowing their inventory for a 24 month period is an important piece of information that normal market counterparties do not have. This would give NSPI an advantage and could lead to better energy prices for Nova Scotia ratepayers:

> MR. WALKER: ... So when you're transacting with a counterparty and you know what their inventory is like for the 24-month period coming up, that's an enormous amount of information that normal market counterparties don't have. It gives you an advantage in the marketplace which can often lead to price.
>
> [Transcript, p. 3014]
>
> MR. COLAIACOVO: Given that NSPI is an active trader in energy markets ... they would be actively pursuing opportunities not only with Nalcor, but with other participants in the market.
>
> ... if Nalcor is selling significant blocks of power into that market, they're going to be an important market participant...
>
> To the extent that NSPI is trading and participating in that market, every scrap of information is valuable.
>
> I think one of the points that -- you know, that has already been made is that forecasts are, in and of themselves, valuable to traders. People pay money for forecasts.
>
> In this instance, they're going to be -- NSPI will be getting a rolling 24-month forecast from another market participant. That's a valuable thing, and it's valuable information.

...

MR. WALKER: And it's really about what information you have relative to other guys that you're competing with in the marketplace.

...

And when you know what a major market seller has available to sell over the next 24 months, that gives you a bit of insight as to where market prices might actually head.

So -- and it's information that, you know, other parties in the marketplace don't actually have, so all of a sudden, you've got a bit of an advantage over the other guy when you're bidding for that piece of business.

And traders, you know, they smell blood. That's their job. And so having that piece of information is enormously valuable from a trader's perspective.

[Transcript, pp. 3020-3023]

[24] In summing up the EAA's advantages, Morrison Park stated as follows:

The Agreement amounts to a right-of-first-refusal for NSPI, albeit under specific limited conditions. The provisions related to the cumulative amount of energy over the life of the Agreement provide further protection to Nova Scotia ratepayers, giving substance to the representations about the benefits of the Maritime Link originally argued before the Board. Further, it is our view that the Agreement does not impose additional costs on Nova Scotia ratepayers that were not already evident in the Maritime Link transaction, nor does it otherwise detract from the proposed Maritime Link project originally proposed to the NSUARB.

[Exhibit M-140, pp. 8-9]

5.1.2 Risks

5.1.2.1 Introduction

[25] During the Compliance Hearing, Intervenors outlined a number of concerns with respect to whether the Board's condition relating to Market-priced Energy had been satisfied. These concerns were summarized by Mr. Chernick and Mr. Parker, the CA and SBA's consultants, as follows:

We conclude that many components of the proposed EAA would reduce the quantity of economy energy, increase the price of that energy, or reduce the value of the energy to NSPI ratepayers, compared to the assumptions in the Application. In more detail, we conclude as follows:

- The quantity of the market-priced energy that would be assured by the EAA is substantially less than the quantity the Application assumes would be available.

> - The EAA product that would be offered in fixed quantities in an annual solicitation is substantially inferior to the market-priced energy assumed in the Application and embedded in Application Figure 4-4.
> - The surplus energy product provided under the EAA may be substantially more costly than the market-priced energy assumed in the Application.
> - The EAA terminates in 2041, while the Application extended the benefits of the economy energy beyond the end of the NS Block in 2052.
>
> Nova Scotia ratepayers would also assume all of the price, quantity, and delivery risks under the EAA, while Nalcor and Emera would bear very little risk.
>
> Compared to Application Figure 4-4, all of these deficiencies increase the costs or reduce the benefits to ratepayers, compared to expectations present in the Application.
>
> In addition, the terminology used in the EAA further increases the risk that NSPI ratepayers would receive even less value than a clearer EAA might produce. This lack of clarity arises from the use of such vague terms as "commercially reasonable" (¶7(c)), "commercially possible," "equivalent economic value to NSPI" (¶4(d)), and several terms in ¶4(c)(ii) discussed in Section VI below, as well as the inconsistency between the language of the EAA and Emera's interpretation of that language, as discussed in Section IV.B below.
>
> Despite the vague and sometimes misleading language, and the EAA's statement that it is only a confirmation of "the terms and conditions under which [Nalcor, NSPI and Emera] will enter into a definitive Energy Access Agreement" (EAA at 1), Emera has no intention of clarifying the EAA ...
>
> [Exhibit M-138, pp. 4-5]

[26] In the course of the hearing, and in final submissions, the Intervenors identified specific risks they believed arose under the EAA. The Board will canvass those risks, in turn.

5.1.2.2 NSPI's Future Load Requirements

[27] Some of the parties questioned whether NSPI had secured all of the Market-priced Energy forecasted in the original application. In that application, it had modelled the availability of up to 2 TWh of surplus energy per year.

[28] In the Compliance Filing, NSPML indicated that it had based its negotiation of the EAA on the load findings made by the Board in the ML Decision:

> ... The Energy Access Agreement provides NS Power with the opportunity to contract for energy in volumes that are consistent with Figure 4-4 from the Application, under Low Load planning assumptions. As noted by the UARB:

> [106] On balance, the Board believes that NSPML's "Low Load" forecast, which most closely aligns with NSPI's current load forecast, is a more realistic scenario than NSPML's "Base Load" forecast. The Board accepts the evidence of Synapse, Levitan and Resource Insight that NSPML's "Base Load" forecast is more in the nature of a high load forecast.
>
> [Compliance Filing, Exhibit N-134, p. 11]

[29] Mr. Gallant confirmed at the Technical Conference that the amount of 1.2 TWh referenced in the EAA stemmed from the "Low Load" forecast in NSPML's original application:

> ... What we did is we modeled surplus energy at Mass hub, and that model forecasted that we would want to take a certain volume of energy, and that was represented in Figure 4-4 which we updated as Undertaking U-3 for the low load forecasts.
>
> So if you take those same components under this arrangement, we believe that that volume of 1.2-terawatts hours, which was predicted by Undertaking U-3, will be taken up if those conditions remained as we forecasted, and this Agreement allows for that to happen.
>
> [Technical Conference, Exhibit M-137, p. 81]

[30] Later during the Technical Conference, he added:

> ... if you look at the data that backs up the Figure 4-4 under Undertaking U-3, you'll see that 1.2-terawatt hours, on average, will deliver or make available -- will make available the same amount as the energy under that forecast.
>
> [Technical Conference, Exhibit M-137, p. 84]

[31] The Board notes that Nalcor's commitment under the EAA to provide, on average, 1.2 TWh of energy per year is the minimum requirement under the terms of the EAA. If Nalcor has the energy available, it must forecast and bid up to 1.8 TWh per year, including in every year the EAA is in effect until 2041 (even after it has satisfied its minimum total requirement of 28.8 TWh). When considered in this context, the Board considers that the commitment secured in the EAA goes beyond the scope of the "Low Load" forecast, and could help to address higher load scenarios.

[32] Based on its review, the Board is satisfied that the commitment secured by NSPI from Nalcor (including the 300 GWh commitment from Emera) for 1.2 TWh of energy per year, on average, is consistent with the Board's findings in the ML Decision with respect to load.

5.1.2.3 Access to Market-priced Energy beyond 2041

[33] The Board noted at paragraph [200] of the ML Decision that while there were legitimate concerns about the availability of Market-priced Energy from Nalcor over the first 24 years of the Maritime Link Project, the evidence clearly showed that there would be no shortage of Market-priced Energy when the Churchill Falls agreement with Hydro Quebec comes to a conclusion in 2041. The Board's view on this matter has not changed and it accordingly finds that the term of the EAA, ending in 2041, satisfies the Market-priced Energy condition.

5.1.2.4 Changes to the EAA in the Final Agreement

[34] Pursuant to Section 2(a) of the EAA, the parties have agreed to negotiate a definitive energy access agreement (the "Final Agreement") incorporating certain commercial terms not included in the EAA including, "tax, audit rights, force majeure and metering provisions and the standard agreement template language previously developed by the parties". Unfortunately, that left the Board and the parties in a position of having to review the EAA without the benefit of having the definitive Final Agreement.

[35] The Board has made this Supplemental Decision on the Compliance Filing on the basis of the EAA, as represented and clarified on the record by NSPI and NSPML. In the event the Final Agreement alters the terms and conditions of the EAA in a way that is detrimental to NSPI ratepayers, the terms of the EAA, as so represented

and clarified, will prevail over the Final Agreement for purposes of determining the recovery of costs by NSPI from its ratepayers.

[36] With that finding the Board sees no need to subject the Final Agreement to any further review or approval process as recommended by the CA.

5.1.2.5 NSPI Acquisition of Energy under Annual Solicitations

[37] Currently, NSPI's solicitations in the energy market typically extend only to daily, monthly or seasonal requests. The annual solicitations under the EAA represent a change to longer solicitations.

[38] During cross-examination of NSPI's witnesses by Mr. McGrath, NSPI committed to a review within the FAM Small Working Group of its procurement policies and procedures, which may need to be changed relative to annual energy solicitations anticipated under the terms of the EAA:

> MR. McGRATH: Before NSPI begins acquiring energy under the EAA, if the Board approves the arrangement, would NSPI commit to specifically engaging the FAM Working Group to conduct a specific review to determine whether any policies and procedures need to be changed to accommodate that anticipated activity?
>
> MR. SIDEBOTTOM: Of course.
>
> [Transcript, p. 2762]

[39] This NSPI commitment was further confirmed by Mr. Landrigan in his Closing Remarks:

> MR. LANDRIGAN: ... Nova Scotia Power and the Board confirmed during the hearing that its procurement decisions, including those under this Energy Access Agreement, will continue to be subject to the provisions of the FAM, including the FAM audits, and other associated Board oversight.
>
> In response to a request from the Province, Nova Scotia Power also confirmed that it will conduct a specific review of its Fuel Manual with the FAM Small Working Group. This review will help safeguard the value for customers by fully examining whether the company's procurement policies and procedures should be modified in order to ensure that the value provided under the Energy Access Agreement is achieved.
>
> [Transcript, p. 3133]

[40] The Board directs NSPI to undertake this Fuel Manual review with the FAM Small Working Group and to file the proposed amendments with the Board by December 31, 2014. The review should include a consideration of the potential and merit in any hedging arrangements that might be made. It should also include a consideration of strategies for mitigating the potential that NSPI might need to generate energy to sell to the market to offset times when it may have committed to take economy energy.

5.1.2.6 End-use Consumption Only – EAA Section 3(e)

[41] Section 3(e) of the EAA states:

> End-Use Consumption - Nalcor Supplied Energy will be for end-use consumption in Nova Scotia only, except that NSPI shall have the right to resell Nalcor Supplied Energy in the event that such Energy is surplus to NSPI's requirements due to variations in NSPI's load or generation identified subsequent to NSPI's acceptance of a Nalcor bid.

[42] Concerns were raised by Intervenors about the restriction to re-sell the energy in light of the potential year in advance commitment. The risk is that NSPI would be left with excess energy it could not offload, which may result in additional costs. The Board notes that the section does give NSPI the right to sell surplus energy due to unforeseen variations in NSPI's load or generation.

[43] The CA explored a risk related to NSPI not being able to sell energy to offset an over-commitment resulting from its annual solicitations under the EAA. Mr. Sidebottom testified this restriction related only to the resale of Nalcor energy provided under the EAA, stating further:

> ... Remember, Nova Scotia Power has many generation sources, and at its maximum at a point in time this might represent, you know, 10 or 20 percent of the energy at any moment in time, and <u>Nova Scotia Power is free to resell other electrons</u>.

> So effectively, we are fully free to sell into the markets because we have many generation sources. And the real intent of this clause is around Nalcor's concern that we aren't becoming a reseller of their energy in alternate markets. [Emphasis added]
>
> [Transcript, pp. 2680-2681]

[44] During further questioning by the SBA, Mr. Janega stated the intent of this restriction was to ensure NSPI does not become a market reseller of the Nalcor EAA energy, adding it does not restrict NSPI from optimizing its energy.

[45] The Board's concern was that NSPI have the opportunity to purchase adequate energy for domestic consumption. The Board does not see NSPI's role as a marketing reseller with its attendant risks. Based on the representations from Mr. Sidebottom and Mr. Janega that the agreement does not restrict NSPI from optimizing the resale of energy originally intended for consumption, but no longer needed due to load or generation variations, and the lack of any restriction on the sale of other electricity, the Board is satisfied that this provision should not impose additional costs on NSPI and its customers. However, any administrative or other costs incurred by NSPI related to the resale of energy will be addressed through the FAM process and prudency reviews.

5.1.2.7 Energy-only Product – EAA Section 3(f)

[46] Section 3(f) of the EAA reads:

> Energy-Only Product - Nalcor Supplied Energy shall be provided to NSPI as an energy-only product. For greater certainty, Nalcor retains all rights and value associated with such Energy in respect of Capacity and GHG Credits.

[47] Intervenors identified concerns that the "energy-only" product differs from that contemplated in the original application, because it comes with no attributes required to satisfy compliance with Federal and Provincial emission or renewable requirements.

[48] The Board explored whether this differs from the original application. NSPI explained:

> MR. SIDEBOTTOM: We weren't modelling it -- although it's in there as a compliant product, it wasn't required for compliance and there was no price associated with an RES factor associated with that energy. It was a pure market price.
>
> MR. DEVEAU: In the original application?
>
> MR. SIDEBOTTOM: Yes.
>
> [Transcript, p. 2854]

[49] An additional cost toward compliance could impact the economic analysis. The SBA explored whether there would be an additional cost of being compliant with renewable requirements if NSPI's load increases from the low load scenario:

> MR. BLACKBURN: But what would you do if -- for instance, I mean, if NSPI needed the credits, you'd have to go out and purchase it, which the ratepayers would have to pay for, so why would you assign those credits to Nalcor?
>
> MR. SIDEBOTTOM: I might turn that around another way and say, why would you pay for a piece of a product that you don't need? If, in the future, you find you need that product, then you go out and find the most economic way to acquire that product at the time. We don't need anything other than economy energy to satisfy the needs of this low-load case.
>
> [Transcript, pp. 2717-2718]

[50] Mr. Sidebottom also confirmed there was nothing in the legislation restricting the surplus from counting toward the Renewable Electricity Standard ("RES").

[51] The Board accepts, for the purpose of interpreting the EAA in the future, the evidence of Mr. Sidebottom that there is no increased cost, beyond the original application, related to the provision that this is an energy-only product.

5.1.2.8 Audit Rights – EAA Section 3(i)

[52] Section 3(i) of the EAA, "Audit Rights", reads:

> Audit Rights - The Parties agree that the audit provisions to be included in the Final Agreement shall be based on the principles of reciprocity, confidentiality of commercially sensitive information, and disclosure of information required by each Party to determine compliance with the Final Agreement.

[53] Audit rights are important for matters related to NL Native Load, hydrology, and alternative spot-markets, among other issues under the EAA.

[54] Intervenors highlighted this as an item that remained undefined. They asserted the rights that NSPI and the Board have are vague, leaving it unclear how these will protect the interests of NSPI ratepayers. This was explored from the perspective of the Board's right to access relevant information:

> MR. O'CONNOR: So the Board has access to this document and all transactions that we might do with the -- or any transaction we would do with the affiliate would, of course, be subject to affiliate scrutiny.
>
> MR. McGRATH: Right. So I'm asking specifically though whether when you go to finalize the audit rights provisions and the final agreement whether you will take steps to include a specific provision in the final agreement that outlines that Board right to access?
>
> MR. O'CONNOR: Yes, we will do that.
>
> [Transcript, pp. 2798-2799]

[55] The Board further explored the audit rights, highlighting concerns with access to the Nalcor data:

> MR. SIDEBOTTOM: ... So as things such as the hydrology and the backup and the forecast are exactly the type of thing we would seek in our audit rights, so that's what we would envision going forward.
>
> [Transcript, p. 2841]

[56] The Province proposed a condition that would ensure the Board have access to information consistent with NSPI's Affiliate Code of Conduct and the FAM provisions.

[57] The Board notes there were numerous assurances provided that NSPI will ensure it has access to the information required to document for the Board, and Board appointed auditors, that its activities have been prudent. In adjudicating cost recovery

by NSPI from ratepayers, the EAA will be interpreted in accordance with this representation.

5.1.2.9 Affiliates - EAA Section 4(a)

[58] Section 4(a) of the EAA states the following:

> Nalcor Forecast - On a monthly basis during the Term, Nalcor will provide a good faith forecast to NSPI of Available Energy forecasted to be available for sale to NSPI for the following 24 months, up to a maximum of 1.8TWh per Contract Year (each such forecast is a **"Nalcor Forecast"**). The Nalcor Forecast shall include a forecast of the total Available Energy denominated by Peak Hours and Off-Peak Hours for each month, all being capable of delivery at the Delivery Point.

[59] Counsel for the Province expressed the concern that this information should not be shared by NSPI with Emera or its affiliates.

[60] The Board notes the need to protect this information for the benefit of ratepayers. In order to ensure that NSPI is prevented from sharing this information with Emera or any related entity, the Board directs NSPI to include appropriate conditions within its Affiliate Code of Conduct and related Guidelines. Proposed amendments are to be submitted to the Board for consideration by December 31, 2014.

5.1.2.10 Alternative Spot Market – Green Energy Pricing – EAA Section 4(c)(ii)

[61] The Intervenors also suggested that there may be risks under the EAA with respect to the pricing of Market-priced Energy. In their submission, NSPI might be required to pay a premium for such energy because its renewable or non-carbon attributes might attract higher prices in New England or other markets.

[62] The pricing of Nalcor Market-priced Energy is described in Section 4(c) of the EAA:

4(c) Nalcor Bid Price - Nalcor will make good faith bids of Nalcor Bid Energy into the NSPI Solicitations. In pricing such bids, Nalcor will consider NSPI's market alternatives and Nalcor's opportunities in other accessible northeast electricity markets available to Nalcor at any time. The sale price of the Nalcor Bid Energy at the Delivery Point shall not exceed the greater of:

(i) the hourly Day-Ahead Price {as defined in the ISO-NE Tariff} at the ISO-NE Mass Hub node (described as "4000_:_.H.INTERNAL_HUB" by the ISO-NE), priced at the hour of delivery. For greater certainty, this price shall be the Day-Ahead Price, and shall not be reduced by any real or implied market fees, transmission tariffs, transmission losses or other charges; and

(ii) any alternative spot-market opportunities identifiable by Nalcor at the time of its bid which are available to Nalcor at any time within one year following the Nalcor bid into the NSPI Solicitation, to the extent Nalcor can demonstrate both a liquid trading node with associated published forward pricing and an actual transmission path, less incremental transmission tariffs, transmission losses and other charges applicable to deliver Nalcor Bid Energy to such market, but for greater certainty, not to reflect a deduction for any costs for Sunk Transmission.

Pricing up to the greater of (i) and (ii) above shall be deemed to be a good faith bid with respect to price.

[Exhibit M-134, Appendix A, p. 6]

[63] No party raised any concern about "green energy" pricing under Section 4(c)(i). Mr. O'Connor confirmed for the Board at the hearing that the ISO-NE Mass Hub node, described as "4000_:_.H.INTERNAL_HUB", is an energy-only pricing index.

[64] However, concerns were raised about the pricing under 4(c)(ii) for an alternative spot-market.

[65] In its Submissions, the Industrial Group stated:

76. NSPML says an alternative market can only be used for brown energy, in amounts and times that are consistent with actual alternative market contracts - <u>but the EAA does not have these limitations</u>. If it was the intent of the parties that the agreement would be interpreted in this way, why not include these limitations within the EAA? [Emphasis added in original]

[Industrial Group Submission, para. 76]

[66] In the pre-filed evidence of Mr. Chernick and Mr. Parker, they referred to the premium being sought in the market for energy with renewable or non-carbon attributes:

> Section 4(c)(i) of the EAA mimics the price-setting formula in the Application, setting the price at the "the hourly Day-Ahead Price at the ISO-NE Mass Hub node." However, Section 4(c)(ii) allows Nalcor to charge a higher price if there is a premium market for clean, renewable, or non-carbon energy in New England or elsewhere (Ontario and New York are the most likely alternative markets). ...
>
> The concern that demand for green energy would cause the price of the economy energy under the EAA to exceed the pricing assumed in the Application ...
>
> [Exhibit M-138, pp. 23-24]

[67] However, NSPML and NSPI assured the Board and the Intervenors at the hearing that the pricing for an alternative spot-market under Section 4(c)(i) would be for an energy-only product.

[68] In questioning from the SBA, Mr. O'Connor confirmed this interpretation:

> MR. BLACKBURN: ... But -- so is it more probable than not? I guess that's my question, that there's probably going to be alternate spot markets and there's going to be a premium attached to it, which means that Nova Scotia Power are going to be paying a premium and the ratepayers are going to be paying a premium?
>
> MR. O'CONNOR: No, I -- I disagree with that completely.
>
> <u>This talks about an alternative spot market, which is for energy only. It is a separate and distinct from whatever the renewables or capacity. Those are separate markets.</u>
>
> They would not -- and the value of those markets would not be in this pricing. And if Nalcor were trying to achieve the value for that, they would have to do it under some other mechanism.
>
> <u>We will not pay for those other attributes through this pricing mechanism.</u> [Emphasis added]
>
> [Transcript, p. 2733]

[69] Moreover, Mr. Smellie, with Nalcor's legal counsel in the hearing room, indicated that this interpretation represented the clear intent of the parties to the EAA:

> ... And we have reconfirmed with Nalcor and the parties are clear that all energy forecast and bid under the Energy Access Agreement is to be and will be an energy-only product consistent with subsection 3(f), which provides that Nalcor supplied energy shall be provided to Nova Scotia Power as an energy-only product.

And so the price cap for Nalcor bid energy or pricing under subsection 4(c) will not be based on green energy pricing, but rather, on economy energy pricing.

MR. DEVEAU: So that includes 4(c)(i) and 4(c)(ii).

MR. SMELLIE: That's correct, sir.

[Transcript, pp. 2896-2897]

[70] As noted later in this Decision, the representations of NSPI and NSPML in relation to pricing will be subject to the oversight of the Board under the FAM process.

5.1.2.11 Timing and Amount of Energy Linked to the Alternative Spot Market – EAA Section 4(c)(ii)

[71] The Intervenors also expressed concern about the scope of Nalcor's right under Section 4(c)(ii) to identify an alternative spot-market opportunity. Their concern was that once Nalcor identified a liquid trading node for an alternative spot-market, along with an actual transmission path, NSPI, if it elected to purchase the energy, would be committed to the higher resulting price of the Nalcor Bid Energy for the entire contract year, even if the alternative spot-market was only available for one day during that year.

[72] Concerns were also raised about when the alternative spot-market had to be identified by Nalcor.

[73] On the latter point first, Mr. O'Connor testified at the hearing that Nalcor must identify the spot-market at the time of the Nalcor Bid into the NSPI Solicitation:

MR. MERRICK: But, for example, if Nalcor were bidding, it would have to be aware of the alternative at the time it bids; am I correct on that?

MR. O'CONNOR: That's absolutely correct, yes.

MR. MERRICK: All right. So that any opportunity that might become apparent to it a month or two down the road wouldn't be -- wouldn't qualify?

> MR. O'CONNOR: That's right. At the time they submit the bid, they have to, at that time, identify if condition (ii) will be some of the pricing, some of the energy will be priced under that.
>
> [Transcript, p. 2653]

[74] Moreover, on the former point, Mr. O'Connor confirmed that the impact on NSPI and its customers of an alternative spot-market will be limited to the amount and duration of the spot-market identified by Nalcor. In cross-examination by Mr. Merrick, he testified:

> MR. O'CONNOR: ... But this market, we will be able to verify that that's the market price <u>for that period</u>. We'll be able to verify that they can get that amount of energy there. So we will know that it is an alternative that they can access. [Emphasis added]
>
> [Transcript, p. 2654]

[75] Later, in cross-examination by Mr. McGrath, Mr. O'Connor confirmed this interpretation:

> MR. McGRATH: And if it identifies that it has an opportunity where it can achieve a better price on one day of the entire contract year, either at the beginning or at the end, it doesn't really matter, is it's alternative price applicable only to that one day, or would it apply to the entire year under the contract?
>
> MR. O'CONNOR: It's only applicable to the volume that could flow on that one day.
>
> [Transcript, p. 2768]

[76] In the Board's view, these representations are unequivocal and readily enforceable as between NSPI and its ratepayers.

5.1.2.12 Redelivery and "Equivalent Economic Value" – EAA Section 4(d)

[77] Under Section 4(d) of the EAA, the delivery of any Nalcor Supplied Energy (i.e., Nalcor Bid Energy which has been accepted by NSPI) can be interrupted by Nalcor and redelivered to NSPI within 365 days. The redelivery must be at a time and in such quantities that the energy has "equivalent economic value to NSPI".

[78] Section 4(d) provides:

> Nalcor Redelivery - Following acceptance by NSPI of a Nalcor bid and prior to the scheduling of such Energy, the timing of delivery of any Nalcor Supplied Energy may at Nalcor's option be interrupted and redelivered provided Nalcor shall redeliver such Energy as soon as commercially possible thereafter at a time and in quantities so that the Energy has equivalent economic value to NSPI and, in any event, Energy not so delivered on the date on which it was first to have been delivered shall be redelivered by not later than 365 days following such date at a time and in quantities so that the Energy has equivalent economic value to NSPI, and the NSPI Solicitation contract term will be extended accordingly, if necessary. Nalcor's obligation to schedule and deliver the daily quantities of Redeliverable Energy is subject to Forgivable Events, provided however that Nalcor shall deliver the total Redeliverable Energy in accordance with the foregoing provisions of this Section 4(d). Redeliverable Energy may not be further interrupted by Nalcor pursuant to the foregoing provisions of this Section 4(d). [Emphasis added]

[79] The Intervenors raised a concern with respect to the determination of "equivalent economic value to NSPI".

[80] Mr. Sidebottom and Mr. O'Connor testified that the intent of Section 4(d) is that NSPI customers will be kept whole in the event Nalcor elects to interrupt and redeliver:

> MR. SIDEBOTTOM: If there's a market opportunity during the period, Nalcor has the right to redirect that energy into an alternate market. Now, while exercising that right, they do have to keep Nova Scotia Power whole through an equivalent value proposition. So they have that opportunity to get into that market, but Nova Scotia Power and its customers are left whole with that particular right.
>
> MR. O'CONNOR: And, sorry, if I just may add to Mr. Sidebottom's comment that it's clear that if the -- if this is exercised, Nalcor shall redeliver such energy as soon as commercially possible. The 365 days is at the outer limit. There is an expectation that it will be done sooner than that. In fact, it's a contractual obligation.
>
> [Transcript, pp. 2656-2657]

[81] Mr. Sidebottom explained the process that would be followed to determine the "equivalent economic value", stating it is a calculation that NSPI currently does in its operations:

> MR. MERRICK: How are you going to keep the customers whole?
>
> MR. SIDEBOTTOM: We will simply ensure that the energy that's redelivered has equivalent value as actually set out in page 6 of the agreement. The energy has the equivalent economic value to Nova Scotia Power. That is how we keep them whole.

MR. MERRICK: And just going with that for a moment, is that simply a case of comparing the price?

MR. SIDEBOTTOM: It's a combination of price and any other costs incurred associated with redirecting that energy, which is quite a typical normal calculation we would carry out in the course of our business. We have interruptions in power on economy energy. We do those calculations today.

...

MR. MERRICK: All right. But you say that you would make the customers whole by doing -- making sure that the energy was equivalent economic value.

So I'm taking -- I'm assuming what you mean by that is when it comes time that Nalcor is now prepared, possibly a year later, to deliver energy that Nova Scotia Power had asked for, that at that time you'd merely do a price -- one of the things you'd do to keep the customer whole is do a price comparison.

And let's assume that the energy being delivered a year later is worth a lot less than it was at the time it was originally committed. How would you do the -- how would you hold the customers whole?

MR. SIDEBOTTOM: It would be at a time, price, and quantity such that the equivalent value was realized for customers. And it works as simply as that. So the quantity is not specified, but the value proposition is. And keeping customers whole is the intent there.

...

MR. MERRICK: All right. And what sort of costs would there be?

MR. SIDEBOTTOM: There may be the cost of replacement energy and any associated value with re-dispatching the fleet at the time. And because this is actually set out as a broad statement of value, it would be whatever effectively was the cost at that point in time due to the energy being moved away from Nova Scotia at that point in time.

MR. MERRICK: So how would the customers be made whole for those additional costs?

MR. SIDEBOTTOM: Again, we would foresee that they be an energy with a certain quantity and price that it would offset other generation that Nova Scotia Power would otherwise foresee. We can easily calculate that value and we'd ensure that that value was equal to the value or the cost of the energy that was removed for redelivery.

MR. MERRICK: Assume the value of the interrupted energy and the now-to-be-supplied energy is the same, so that the only cost that has been incurred has been the cost of the interruption.

MR. SIDEBOTTOM: That would be a cost.

[Transcript, pp. 2657-2662]

[82] NSPI's witnesses stated at the hearing that the intent of Section 4(d) was that NSPI customers would be "kept whole" when Nalcor redelivers energy it has interrupted. Accordingly, in adjudicating any issues related to cost recovery between

NSPI and its ratepayers, the Board will interpret Section 4(d) subject to the "kept whole" representation, which means that ratepayers will be put in the same position they would have been had Nalcor not interrupted its Nalcor Supplied Energy.

5.1.2.13 Forgivable Events, Including Force Majeure – EAA Section 4(e)

[83] The Intervenors also raised concerns with respect to the risk that Nalcor might be entitled to avoid its commitment to forecast, deliver or redeliver energy by reason of forgivable events, particularly NL Native Load or hydrology events in NL.

[84] Forgivable events are described in Section 4(e) of the EAA:

> Forgivable Events - Nalcor's requirements to bid the Nalcor Forecast or schedule delivery of the Nalcor Bid Energy as provided in Section 4(b) will be reduced to the extent Nalcor is unable to bid the Nalcor Forecast or schedule delivery of the Nalcor Bid Energy due to any one of the following: (i) Nalcor requires such Energy to meet NL Native Load; (ii) hydrology events in NL; (iii) a force majeure event; (iv) a safety event; (v) a forced outage; or (vi) an action required to be taken by any Party to comply with Good Utility Practice (each of which is a "**Forgivable Event**").

[85] A further concern raised by Intervenors is that the term "force majeure event" has yet to be defined in the EAA. As noted earlier in this Decision, it is to be defined by the parties under Section 2(a), along with other matters such as "audit rights".

[86] The CA canvassed this issue with the NSPML/NSPI witness panel at the hearing:

> MR. MERRICK: All right. But my problem is this. When you look at those two clauses, assume for the moment that in a particular year, or perhaps over the whole term of the contract, native load pre-empts or is -- native load requires the excess or surplus energy that Nalcor has, that extra 40 percent surplus.
>
> Assume for the moment that native load takes it all up. Does that clause override 6(a)? In other words, is even the 1.2 not a guaranteed minimum?
>
> MR. SIDEBOTTOM: So native load and the hydrology are not forgivable events when it comes to the 1.2 average through time.

MR. MERRICK: Where does it say that?

MR. SIDEBOTTOM: Under 6(a), it's only subject to 7(e)(i) and force majeure is the commitment excusable, so it's not hydrology and load-related over the average of the term.

MR. MERRICK: My problem is, I can understand somebody perhaps advancing that as an interpretation, but I don't see it expressly set out in the contract itself.

There doesn't seem, to me, to be anything to limit 4(e).

MS. TOWER: It is the agreement of the parties. It is the understanding of the parties that that's how it works, that the 1.2 is not -- the 1.2 on average commitment is not forgivable by hydrology or native load.

MR. MERRICK: So that your understanding is that when you read all the clauses together, native load may, in fact, reduce the obligation to bid -- to forecast or to bid energy down to a maximum or a minimum, an amount of 1.2, and that that you cannot encroach on for native load. Is that correct?

MR. O'CONNOR: No, that's not correct. I believe if we look at that section, which is forgivable events, so Nalcor's requirement to bid the forecast or schedule delivery is then subject to those items there.

It does not in any way alleviate them of the obligation over the term to meet at least the 1.2 terawatt hours.

MR. MERRICK: All right.

MR. O'CONNOR: So the forecast itself could drop below it, but their overall obligation for the entire term is not affected by that.

MR. MERRICK: At the end of the 24 years, they must have provided the 1.2 average, so that is our solid minimum guaranteed amount. Is that correct?

MS. TOWER: That is correct.

[Transcript, pp. 2631-2633]

[87] This issue was also canvassed by counsel for the Province in his cross-examination:

MR. McGRATH: ... I'd like to move into the agreement, Section 6(a), please.

You've had some discussion about this provision earlier today, and that's the one that establishes the 1.2 terawatt hour commitment on the part of Nalcor. And it's noted that it's subject to force majeure events.

And you've had some discussion as well about the definition of force majeure, and I just want to touch upon that again just very briefly.

Force majeure is used in a number of different places in the document. It's used with respect to the 1.2 terawatt hour commitment. It's also used as a feature of a forgivable event.

Is it intended that force majeure has the same definition throughout the document?

MS. TOWER: Yes.

MR. McGRATH: And if we can move now in the agreement to Section 4(e).

Looking at the definition of forgivable event, which includes force majeure and some other items, can I conclude from that that because force majeure is separated from those other items that none of those other items are included within the definition of force majeure?

MS. TOWER: Yeah.

MR. McGRATH: And more specifically, the NL native load is not going to be an element of force majeure?

MS. TOWER: That is correct.

...

MR. McGRATH: So another item included there was Newfoundland and Labrador hydrology events, so that also would be excluded from the definition of force majeure.

MS. TOWER: That is correct.

[Transcript, pp. 2783-2786]

[88] Based on the interpretation and representations made by NSPI and NSPML witnesses, the Board is satisfied that Nalcor's commitment to provide, on average, 1.2 TWh of energy per year throughout the term of the EAA cannot be circumvented by forgivable events such as NL Native Load and hydrology events in NL. The Board understands that Nalcor's commitment of 1.2 TWh per year, on average, can only be avoided by force majeure.

[89] With respect to the definition of "force majeure", the SBA pursued that issue with Ms. Tower:

MR. BLACKBURN: Okay. Now, my second question is, where is force majeure defined in this agreement?

MS. TOWER: So force majeure is not defined in this agreement yet. It will be defined in the next version of this agreement.

> It has been defined in the Energy and Capacity Agreement and the other agreements that we negotiated in the set of formal agreements. And my expectation is that that definition, the definition that ends up in the agreement, would be very similar to that.
>
> [Transcript, p. 2727]

[90] In cross-examination by counsel for the Province, Mr. O'Connor acknowledged that there is a definition of force majeure in the Edison Electrical Institute Standard Form Master Power and Sale Agreement, which Nalcor and NSPI have adopted by virtue of Section 5(f) of the EAA.

[91] Counsel for the Province expressed some concern in his Final Argument that force majeure was to be defined later in the Final Agreement:

> Force majeure is a forgivable event but it is also a significant term in its own right. A force majeure event excuses Nalcor from honouring its commitment to make an average of 1.2 terawatt hours of energy available to NSPI over the term of the contract and can also excuse Emera and Nalcor from providing the variance amounts intended to backstop this fundamental commitment to the agreement.
>
> Since force majeure overrides the annual obligation to bid, sell, and deliver and the committed 1.2 terawatt-hour per year average amount of available energy, it's an obligation which goes to the very core of the Energy Access Agreement.
>
> It is a critical item and yet, for some reason, it's been left entirely undefined in the agreement put before the Board.
>
> ...
>
> Uncertainty around such a critical term in the agreement is a significant risk to ratepayers.
>
> [Transcript, pp. 3245-3246]

[92] In terms of any potential impact upon NSPI's ratepayers, the Board will rely on the representations and clarifications provided by NSPML and NSPI at the hearing with respect to the scope of force majeure, notwithstanding the Final Agreement.

5.1.2.14 Fulfillment of Nalcor Commitment - EAA Section 6(a)(iii)

[93] With reference to Section 6(a)(iii), concern was raised regarding the potential for double counting the Nalcor energy commitment when a forgivable event occurs. During the hearing this issue was addressed and both NSPI and NSPML stated that forgivable events would not be included in the Nalcor commitment calculation. In his Closing Remarks, counsel for NSPML, Mr. Smellie, confirmed that this was also Nalcor's intent and the meaning of that provision.

[94] Further, Mr. Sidebottom, Mr. O'Connor, and Ms. Tower all agreed that the wording of that section in the EAA would be changed to make it clear that committed amounts would not be eroded by forgivable events:

> MR OUTHOUSE: ... And then it seems to me, when I read 6(a)(iii), that energy which was not supplied counts towards the fulfillment of the 1.2 average commitment.
>
> So that's the problem I'm having with it, and I would ask you to respond whether that's the intent, as you understand it, or that's the effect as you understand it.
>
> ...
>
> MR. O'CONNOR: ... I can speak to the intent. So the intent is not to double count any volumes at all. And it will just take me a moment or maybe a couple of moments to ---
>
> MR. OUTHOUSE: All right.
>
> MR. O'CONNOR: --- follow up. ... <u>So in that case, the forgivable event would reduce the bid amount, so it wouldn't be included in the calculation in that case.</u>
>
> MR. OUTHOUSE: I appreciate that, Mr. O'Connor, and I'm not trying at all to be difficult. I'm concerned that despite what was said this morning that the 1.2 terawatt hours on average commitment ---
>
> MR. O'CONNOR: Yes.
>
> MR. OUTHOUSE: --- gets eroded by forgivable events. And I thought I heard from the panel this morning that that did not happen.
>
> MR. O'CONNOR: No.
>
> MS. TOWER: No.
>
> MR. O'CONNOR: No, that -- <u>it does not get eroded</u> ---
>
> MR. OUTHOUSE: So ---

MR. O'CONNOR: --- by forgivable events.

MR. OUTHOUSE: --- if this language that I've referred you to permits that, on reflection, if you read that, it's going to be changed, I take it?

MR. SIDEBOTTOM: Yes.

MR. O'CONNOR: Yes.

MS. TOWER: Yes.

MR. O'CONNOR: It would change ---

MS. TOWER: We'll make it clear because that is not the intent.

MR. O'CONNOR: That's not the intent at all. [Emphasis added]

[Transcript, pp. 2805-2807]

[95] This was confirmed by Mr. Smellie in Final Argument:

MR. SMELLIE: The first matter arose at or about transcript page 2880, and it concerns your conversation with the panel, Mr. Chair, about paragraph 6(a)(iii) of the Energy Access Agreement.

We have reviewed the provision, both internally and with Nalcor, and as explained by the panel yesterday, the intent and meaning of this provision is that when Nalcor bid energy is accepted but is not supplied due to a forgivable event, then that energy will not count towards the fulfillment of the commitment.

[Transcript, p. 2895-2896]

5.1.2.15 "Shall Compensate NSPI Accordingly" - EAA Section 7(e)(viii)

[96] Section 7(e)(viii) of the EAA reads:

If either Emera or Nalcor is unable or fails to meet their respective variance amount obligations, such parties shall compensate NSPI accordingly.

[97] A number of parties expressed concern about the vagueness and imprecision of this clause. This concern was best summarized in argument by counsel for the Province, who stated as follows:

Section 7(e)(viii) is the ultimate remedy for NSPI in respect of Nalcor's commitment to provide an average 1.2 terawatt hours per year over the term of the contract. If it cannot meet this commitment and backstop obligations of Emera and Nalcor also fail, Emera and Nalcor will compensate NSPI accordingly.

> The problem is, how that compensation will be determined is entirely unclear. Worse still, when questioned about this, NSPI's witnesses seem to suggest that the market price cap might be used to set this amount even though that would be the worst rate that ratepayers would expect to see.
>
> Clearly, there's some unfinished thinking around this provision. As it is NSPI's final remedy, NSPI ratepayers are being put at risk by this uncertainty.
>
> [Transcript, p. 3249]

[98] The Province, as one of its conditions, suggested if the Board determines that any amount of compensation NSPI might receive is insufficient, ratepayers must receive the benefit of the compensation that NSPI should have received, but did not.

[99] The Board notes that assurances were given by NSPI in evidence that NSPI ratepayers would be "kept whole" as a result of this provision. Accordingly, in adjudicating any issues related to cost recovery between NSPI and its ratepayers, the Board will interpret Section 7(e)(viii) subject to the "kept whole" representation, which means that ratepayers will be put in the same position they would have been had Emera or Nalcor met their respective variance amount obligations.

5.1.2.16 Emera/NSPI Wind for Variance Amount - EAA Section 7(f)(i)

[100] In the event of a variance under the EAA, Emera is responsible for part of the variance up to a maximum of 300 GWh per year. Section 7(f)(i) of the EAA provides NSPI the option, but not the obligation, to construct or contract wind generation to mitigate some or all of the variance included in the Emera variance amount. If NSPI exercises the option, Emera's obligation to provide the Emera variance amount shall be reduced pro-rata. The Province and other parties are concerned that NSPI must demonstrate it is in the best interests of ratepayers for it to exercise this option.

[101] The Board agrees that if NSPI chooses to build such generation then it must apply, under Section 35 of the *Public Utilities Act*, for capital work approval

justifying the wind project as the lowest cost alternative. Alternatively, if NSPI decides to contract with a third party for wind generation pursuant to Section 7(f)(i) of the EAA then it must, applying the test of prudence, justify it as the lowest long-term cost alternative in any application to recover those costs.

5.1.2.17 Variance Amount – Nalcor Balancing - EAA Sections 7(f) & 7(g)

[102] Pursuant to Section 7(g) of the EAA, in the event Emera and/or NSPI exercises its option to construct wind generation, Nalcor will enter into a balancing services agreement to support the megawatt capacity of the wind generation up to 100 MW, by providing balancing services.

[103] In its written submission the Industrial Group expressed the concern that the term of the balancing services agreement is not tied to the EAA term and if a wind project were constructed to meet the variance obligation, this section of the EAA may commit Emera and/or NSPI to take balancing services for a period that is much longer than the EAA itself. That issue was clarified by counsel for NSPI during final argument by referring to Appendix 1 of the EAA governing the Nalcor balancing service. Mr. Landrigan, counsel for NSPI, stated:

> MR. LANDRIGAN: So I believe it's clear in the Energy Access Agreement in Appendix 1, item number 1 in the Appendix, that the balancing service is -- is on an annual basis and an option on an annual basis and is variable in terms of quantity.
>
> So in each year, we could choose whether we would trigger a zero or 100 megawatts of the balancing service. And if we choose zero, we have the option to go out and achieve that balancing service through other means. So I do disagree with her statement.
>
> (SHORT PAUSE)
>
> MR. DEVEAU: Sorry; you're talking there about the ability to nominate up to a maximum of 100 megawatts. So the nomination is an annual process that, again, you could choose zero if you wished and it has to be done every year?
>
> MR. LANDRIGAN: Yes.
>
> [Transcript, p. 3137]

5.1.3 Findings on Condition relating to Market-priced Energy

[104] Based on the representations and clarifications given by NSPI and NSPML, including the interpretation of the EAA, the Board finds that the EAA satisfies the Market-priced Energy condition. In any issue related to cost recovery from ratepayers by NSPI, the EAA will be interpreted in light of these representations and clarifications. In the event the Final Agreement alters the terms and conditions of the EAA in a way that is detrimental to NSPI ratepayers, the terms of the EAA, as so represented and clarified, will prevail over the Final Agreement for purposes of determining the recovery of costs by NSPI from ratepayers.

[105] The Province, and other Intervenors, had recommended that the Board impose a number of conditions. The Board considers that interpreting the EAA in accordance with the above representations and clarifications is a more appropriate manner of dealing with the concerns raised by the Province and other Intervenors. However, the Board observes that, as a practical matter, the end result, on a number of issues, is very similar to the conditions proposed by the Province.

5.1.4 Fuel Adjustment Mechanism

[106] It is important to note that the Board, and NSPI's customers, will be able to ensure that NSPI's future purchases of Market-priced Energy are conducted on reasonable and prudent terms. In its ML Decision, the Board stated:

> [231] The Board notes that NSPI will be required to act prudently in the acquisition of Market-priced Energy as it would with all other fuel related decisions. Decisions related to the purchase of Market-priced Energy will be subject to the provisions of NSPI's Fuel Adjustment Mechanism and the oversight that occurs under that mechanism.
>
> [ML Decision, para. 231]

[107] In the Compliance Filing, it was acknowledged that NSPI's obligations to make prudent power procurement decisions would extend to solicitations described in

the EAA. At the Technical Conference, NSPI's responsibilities under the FAM were acknowledged by Mr. Gallant:

> ... Nova Scotia Power customers can rely upon the fact that this is essentially a FAM transaction. It's not fuel, but it is imported power, and that it has to be done in accordance with the practices and procedures that ensure a fair and transparent competitive solicitation is in place for the import of this energy, as it would be for all of Nova Scotia Power's commercial transactions. ... [Emphasis added]
>
> [Technical Conference, Exhibit M-137, p. 87]

[108] Mr. O'Connor, who is responsible for NSPI's fuel related transactions, agreed with this obligation placed upon the utility:

> ... Nova Scotia Power goes through many – [...] -- many solicitations on a regular basis for both solid fuel, natural gas, and electricity, and all of those processes are well documented. We go through a competitive process to get as many bidders as possible, so we can ensure the lowest price outcome for our customers. It's documented and it's open for review from the UARB throughout our regular processes. So we will adhere to that strictly ... [Emphasis added]
>
> [Technical Conference, Exhibit M-137, p. 88]

[109] This was acknowledged again at the hearing by Mr. Landrigan in his Final Argument.

[110] The Board reiterates its view that NSPI will be held accountable for its purchases of Market-priced Energy from Nalcor (or, in the alternative, its decision to forego such purchases), in similar fashion to all of its other fuel related transactions.

5.2 What should be the reporting requirements for NSPML during the course of the ML Project?

[111] The reporting requirements are set out in s. 7 of the *ML Regulations*:

> **Project report**
> 7 (1) An applicant must file a project report on the Maritime Link Project containing the details required by subsection (2) with the Review Board:
>
> (a) on or before December 31, 2013; or
>
> (b) on or before another date the Review Board orders, as it considers necessary as a result of the progress of the Maritime Link Project.
>
> (2) A project report must set out all the following for the Maritime Link Project:

(a) detailed engineering and design information;

(b) updated and current cost estimates and actuals;

(c) any material changes to any of the information submitted to the Review Board under Section 5.

[112] In the ML Decision, the Board adopted the recommendations of Enerco, Board Counsel's consultant, and directed as follows:

> [405] Enerco, in Undertaking U-31, recommended filing of various reports by NSPML during the design and construction phase of the ML Project. The Board has reviewed Enerco's recommendations and generally agrees that given the size of the ML Project and that the final engineering design and tender awards are not completed, it is appropriate for NSPML to provide regular reports to the Board.
>
> [406] NSPML, in its Closing Brief, also agreed with Enerco's recommendations. However, NSPML suggested that before the Board finalizes its reporting requirements, it would like to meet with Board staff to better understand the information being requested. The Board agrees this would be an efficient process. The information noted above by NSPML at pages 56-57 of its Closing Brief could form the basis for the discussion. The Board directs that it receive reports no later than June 15th and December 15th of each year, unless otherwise directed by the Board. As noted earlier, the Board believes independent engineering reports will be critical to keeping the Board informed. The Board expects this consultation process to be carried out expeditiously and Board staff are to report back to the Board for approval of the reporting requirements by October 15, 2013.
>
> [ML Decision, paras. 405-406]

[113] On November 8, 2013, Board staff provided a report to the Board which was filed as an exhibit to this proceeding.

[114] There is agreement from NSPML as to the reporting requirements relating to the Maritime Link Project.

[115] As noted in the ML Decision, detailed reports must be filed by NSPML on a semi-annual basis, on June 15 and December 15 each year. The reports shall commence December 15, 2013. Updated status reports must be filed quarterly.

[116] NSPML's Decision Gate 3 report must be filed by December 15, 2013.

[117] All items identified in Enerco's Undertaking U-31 will be included in NSPML's reports, as amended to reflect the latest updated project schedule: see the revised Articles 3.1 – 3.3 in Exhibit M-141.

[118] Any reports provided by NSPML to the Federal Government, including engineering or financial reports, shall also be filed with the Board.

[119] Further, any independent engineering reports required by NSPML shall be filed with the Board, with NSPML providing any comments of its own in the transmittal letter. The independent engineering reports will conform with the following structure:

> **Initial Report** will provide (this will be issued for financial close, which will be a maximum of 90 days after Nalcor's financial close):
>
> - A brief description of the Project facilities and key procurement contract agreements
> - The principal assumptions, opinions, conclusions and summarized pro forma operating results
> - Risks identified through the technical review, and any mitigation options
>
> **Periodic Report** (prepared following financial close and during construction) will cover:
>
> - The general status of construction versus the milestone schedule
> - Status of the budget versus actual expenditures
> - Status of planned contract expenditures versus actual
> - Status of major change orders or claims
> - Any areas of concern and actions being taken of which the IE is aware
>
> **Drawdown Certification**
>
> - The IE will prepare monthly drawdown confirmation certification that provides the IE's opinion regarding matters relating to such requisition or drawdown certificate (such as the status of Project costs relative to the Project budget, the status of the schedule of the Project and expected Commercial Operation Date, and the conformity of the work completed with technical and contractual requirements).
>
> **Verification of Project Completion**
>
> - The IE will confirm Project completion with project certification which will include confirmation of:
>   - The review of construction contracts' completion certificates
>   - Monitoring of successful completion of punch list items (by telephone)
>   - One final visit to the Project site to verify punch list items have been completed

[120] All reporting requirements outlined above shall remain in effect unless varied or ordered otherwise by the Board.

5.3 Does the Compliance Filing satisfactorily address the other conditions imposed by the Board?

[121] As noted earlier in this Decision at paragraph [3], the Board directed that other terms and conditions apply to the Maritime Link Project, including conditions relating to AFUDC, a Code of Conduct, and others. The Board also directed that details be provided with respect to the asset demarcation for the Woobine transfer.

[122] In its Compliance Filing, NSPML agreed to and accepted each of these conditions.

5.4 Should the ML Project be approved?

[123] Based on the findings made in this Decision, the Board is satisfied that the conditions outlined by the Board in the ML Decision have been satisfied such that the Maritime Link Project is approved in accordance with the ML Decision and this Supplemental Decision.

[124] The Board reserves its jurisdiction on the issue of costs.

[125] An Order will issue accordingly.

6.0 SUMMARY OF BOARD FINDINGS

[126] In a Decision dated July 22, 2013 [2013 NSUARB 154] ("ML Decision"), the Board concluded, applying the test under s. 5(1)(a) of the *ML Regulations*, that the Maritime Link Project (with Market-priced Energy factored in) represents the lowest long-term cost alternative for electricity for ratepayers in Nova Scotia.

[127] In its ML Decision, the Board imposed a condition to its approval of the Maritime Link Project that NSPML obtain from Nalcor the right to access Nalcor Market-

priced Energy (consistent with the assumptions in the Application as noted in NSUARB IR-37 and Figure 4-4) when needed to economically serve NSPI and its ratepayers; or provide some other arrangement to ensure access to Market-priced Energy.

[128] Among its other findings, the Board directed that certain filing and reporting requirements apply to NSPML respecting the Maritime Link Project, and also directed various other terms and conditions, including directions relating to AFUDC, a Code of Conduct, and others.

[129] In its Compliance Filing provided to the Board on October 21, 2013, NSPML filed an Energy Access Agreement ("EAA") executed by Emera, Nalcor and NSPI. The EAA was intended to satisfy the principal condition with respect to NSPI's access to Nalcor Market-priced Energy. NSPML also agreed to and accepted each of the other conditions imposed by the Board in its ML Decision.

[130] Based on the representations and clarifications given by NSPI and NSPML, including the interpretation of the EAA, the Board finds that the EAA satisfies the Market-priced Energy condition. In any issue related to cost recovery from ratepayers by NSPI, the EAA will be interpreted in light of these representations and clarifications. In the event the Final Agreement (which the same parties are to negotiate later) alters the terms and conditions of the EAA in a way that is detrimental to NSPI ratepayers, the terms of the EAA, as so represented and clarified, will prevail over the Final Agreement for purposes of determining the recovery of costs by NSPI from ratepayers.

[131] Based on the findings made in this Supplemental Decision, the Board is satisfied that the conditions outlined in the ML Decision have been met and that the

Maritime Link Project is approved in accordance with the ML Decision and this Supplemental Decision.

[132] The Province, and other Intervenors, had recommended that the Board impose a number of conditions. The Board considers that interpreting the EAA in accordance with the above representations and clarifications is a more appropriate manner of dealing with the concerns raised by the Province and other Intervenors. However, the Board observes that, as a practical matter, the end result, on a number of issues, is very similar to the conditions proposed by the Province.

[133] The Board notes that relying on the representations and clarifications removes risks to NSPI's customers from the issues canvassed by the Intervenors in this matter. Put more directly, NSPI bears all the risk that the EAA will be applied or interpreted in any way inconsistent with the Board's findings in this Decision.

[134] Further, it is important to note that the Board, and NSPI's customers, will be able to ensure that NSPI's future purchases of Market-priced Energy are conducted on reasonable and prudent terms, in similar fashion to all of its other fuel related transactions. These transactions will all be subject to the oversight of the Board under the FAM process.

[135] In addition to the conditions and directions imposed in the Board's ML Decision, the Board further directs as follows:

a) That NSPI to undertake a Fuel Manual review with the FAM Small Working Group and to file the proposed amendments with the Board by December 31, 2014.

b) That NSPI to include appropriate conditions within its Affiliate Code of Conduct and related Guidelines to prevent information received from Nalcor, including its 24 month forecast, from being shared with Emera or any related entity. NSPI is directed to file the proposed amendments with the Board by December 31, 2014.

c) That detailed reports must be filed with the Board by NSPML on a semi-annual basis, on June 15 and December 15 each year, commencing December 15, 2013. Updated status reports must be filed quarterly.

[136] In conclusion, the Board considers it appropriate to highlight the potential benefits of the EAA to NSPI and its customers. In this respect, the Board found the evidence of Morrison Park to be both instructive and compelling, in that they described the practical "market" benefits of the EAA. The benefit of the EAA is that it will provide NSPI with real and tangible advantages when it participates in the energy market. These benefits will necessarily flow to its customers.

DATED at Halifax, Nova Scotia, this 29th day of November, 2013.

Peter W. Gurnham

Roland A. Deveau

3

Appendix D

Email dated October 27, 2009

3. PURPOSE OF THE WATER MANAGEMENT AGREEMENT

The purpose of a water management agreement is to coordinate power and energy production from facilities on a body of water to maximize energy production over time. The amounts of power and energy produced from a generating facility are functions of the quantity of water available at the generating station at any given time. If natural flows arrived at the generating station in exactly the right amount and when required for production, there would be no need for water management. However, natural flows are not synchronized to production requirements. Therefore, reservoir storage is required to regulate the flow. For a downstream operator, control of flows from upstream facilities may also be required in order to regulate flow to the downstream generating station.

Coordinating power and energy production maximizes the amount and value of power and energy that can be produced from the Churchill River. Coordination of production at the generating stations regulates the flow of water between the stations to best utilize the river system's storage capability and the facilities' generating capacity. Flow regulation increases the control and predictability of energy production at a generating station and optimizes the use of the available water within the constraints of existing contractual supply obligations.

Nalcor and CF(L)Co are both suppliers[8] within the meaning of the Water Management Regulations. Coordinating generation to regulate flow will mean that each of the suppliers will, from time to time, adjust its own production and have that adjustment compensated through complementary production at another facility. For example, CF(L)Co's delivery requirements to its customers could be met by production from both the Churchill Falls and lower Churchill facilities. This would permit water flows from Churchill Falls to the lower Churchill plants to be adjusted, thereby managing the volumes of water to the lower Churchill facilities at a given time. This brings greater energy production on the Churchill

[8] Subsection 2(h) of the Water Management Regulations.

River by reducing the inefficient use of water at the lower Churchill facilities. As an example, during periods of high natural inflows to the lower Churchill, decreased production at Churchill Falls would reduce spillage at the lower Churchill facilities. The reduced production at Churchill Falls would be matched by increased production at the lower Churchill facilities to meet CF(L)Co's delivery requirements. This would be balanced at a later time when Churchill Falls would produce equivalent energy to meet Nalcor's delivery requirements. In effect, energy has been "banked" and later withdrawn.

A water management agreement is required to provide the mechanisms of coordinated production. The operation of the agreement will ensure the efficient use of water on the river system by ensuring that water is available to meet all producers' requirements, while maximizing the energy produced from the water resource.

Uncoordinated production among the Churchill River facilities could result in either excessive or insufficient water at the lower Churchill facilities. Excessive water will result in spill. Insufficient water to meet delivery schedules will result in excessive drawdown. Either case represents inefficient use of the available water. Flow regulation is therefore an important factor in fulfilling the efficiency policy contained in subparagraph 3(b)(i) of the EPCA.

3.1. Efficient Power Production through the WMA

The control of the rate at which water is delivered to a hydraulic generating facility increases the plant's ability to produce power on demand. The ability to regulate the flow of water is a result of having adequate storage. The degree of flow regulation determines a plant's firm power and energy capability.

Because of their ability to store a tremendous quantity of water, the upper Churchill reservoirs will provide the primary flow regulation required on the Churchill River. As previously mentioned, those reservoirs have a live storage capacity of approximately 30 billion m^3 of water. This is enough to allow the spring runoff to be stored in the reservoirs and held over as required for production. Because of the topography of the lower Churchill River, the capacities of the reservoirs at Gull Island and Muskrat Falls will be much smaller. The Gull Island reservoir will have approximately 580 million m^3 of live storage, while Muskrat Falls will have live capacity of only 50 million m^3. Put another way, the upper Churchill reservoirs have a capacity of approximately fifty times the capacity of the Gull Island and Muskrat Falls reservoirs combined.

Water management through coordination of flows and storage mitigates the effects of irregular delivery requirements and production at Churchill Falls. For example, in any month, CF(L)Co deliveries could be requested in a manner that calls for Continuous Energy to be produced at an increased rate for part of the month with the remainder of the Continuous Energy to be produced at a reduced rate later in the month.

Irregular production at Churchill Falls will have different effects on the lower Churchill facilities depending upon the uncontrolled natural inflows at various times of the year. In many months, the lower Churchill facilities would have insufficient water for production requirements during periods of reduced production at Churchill Falls. However, during the spring runoff, there would be excess water, resulting in spillage, during periods of increased production at Churchill Falls. These problems would be compounded if full CF(L)Co delivery of Continuous Energy was scheduled early in one month followed by full production late in the following month.

These effects can be illustrated with two examples showing maximum production early in the month and minimum production later in the month. The first example reflects March conditions, while the second example reflects the spring freshet in May. In each case, Churchill Falls production would be as follows:

Table 1: Irregular CF(L)Co Production Profile

Continuous Energy – First 20 days of month	4,765 MW
Recall and Twinco	495 MW
Total – First 20 days of month	**5,260 MW**
Continuous Energy – Last 11 days of month	900 MW
Recall and Twinco	495 MW
Total – Last 11 days of month	**1,395 MW**

The resulting releases into the lower Churchill reservoirs would be as follows for the above production values:

Table 2: Irregular CF(L)Co Production Water Release

Daily Churchill Falls Water Release – First 20 days of month	160 million m^3
Daily Churchill Falls Water Release – Last 11 days of month	42 million m^3

During the March timeframe, uncontrolled inflows into the Gull Island reservoir will be minimal and under average and dry year conditions are as follows:

Table 3: Gull Island Uncontrolled Inflows March

Daily Uncontrolled Natural Inflows – Average Year	6 million m^3
Daily Uncontrolled Natural Inflows – Dry Year	0.7 million m^3

Under average conditions, the resulting production at Gull Island would be 1,519 MW for the first 20 days and 443 MW during the last 11 days of March. During a dry period, this scenario would require production levels of 1,471 MW during the first 20 days of March, and 395 MW during the last 11 days. Consequently, without a water management agreement, Nalcor would be limited to approximately 400 MW of continuous delivery in a long-term power purchase agreement for Gull Island. Such an arbitrary constraint on lower Churchill delivery schedules is unnecessary and is incompatible with the concept of the efficient use of the resource.

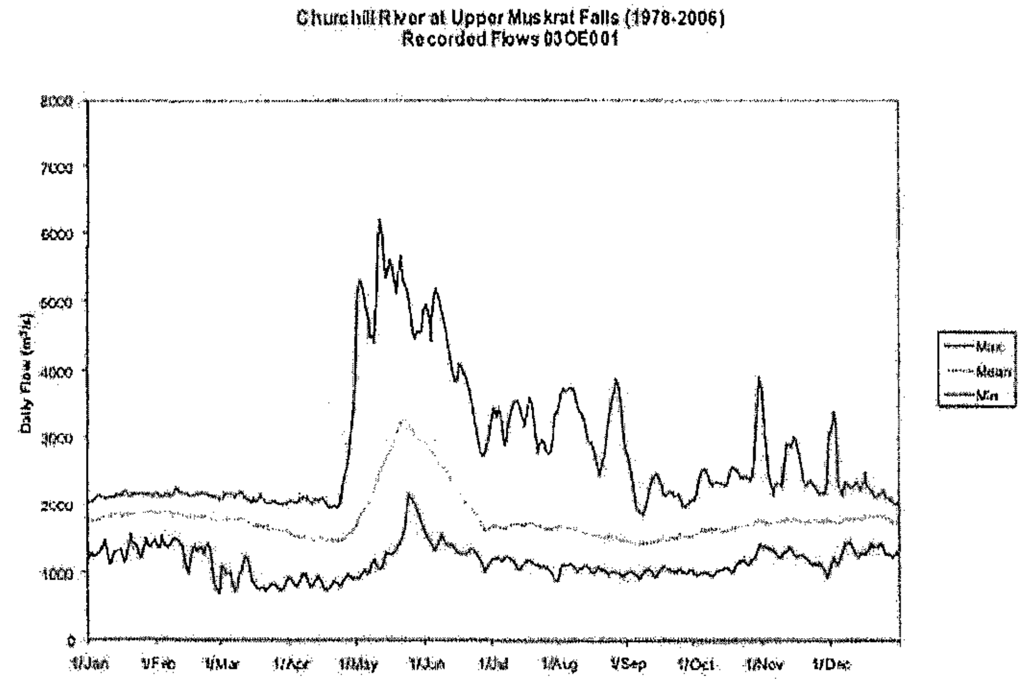
During the May timeframe, uncontrolled inflows into the Gull Island reservoir from snow melt and precipitation under average and wet year conditions are as follows:

Table 4: Gull Island Uncontrolled Inflows May

Daily Uncontrolled Natural Inflows - Average Year	94 million m^3
Daily Uncontrolled Natural Inflows - Wet Year	154 million m^3

Under average conditions, the resulting production at Gull Island would be 2,330 MW for the first 20 days and 1,253 MW during the last 11 days of May. During a wet period, this scenario would require production levels of 2,879 MW during the first 20 days of May, and 1,803 MW during the last 11 days. Since the optimized capacity of Gull Island is 2,250 MW, the surplus inflows would be spilled.

The preceding analysis uses historic monthly averages and daily flow averages instead of peak daily flows. The use of average values understates the extent of the spillage that will result during periods of peak flow. The chart below illustrates the recorded minimum, mean and maximum flows, month over month and within each month, and how monthly average values offer a conservative view.



Source: Environment Canada 2007, Internet site.

Figure 4: Muskrat Falls (Monitoring Station 03OE001) Hydrograph

In the absence of a water management agreement, Nalcor would not even have advance knowledge of expected flows from the Churchill Falls facility to enable it to take steps to mitigate spillage through advance drawdown of the lower Churchill reservoirs.

These outcomes are not consistent with maximizing the long-term energy generating potential of the Churchill River, as contemplated in Subsection 3(1) of the Regulations.

In the absence of a water management agreement, Nalcor would be required to utilize the water as it became available. Given the limited storage capacity in the Gull Island reservoir (approximately three to four days of maximum flow from the upper Churchill facilities), Nalcor would have to turbine the water and produce energy at the time that it was available; it would be required to "chase the flows" from the upper Churchill. Spills would be likely during the period of the spring runoff, resulting in wasted energy.

A water management agreement addresses these issues by enabling Nalcor to produce energy for CF(L)Co during those periods when CF(L)Co has increased deliveries and during the spring runoff. Water held back and stored for Nalcor can then be utilized for Nalcor at a later period when CF(L)Co deliveries are reduced. This minimizes spillage and enables Nalcor to optimize its long-term energy producing capability, in accordance with the provisions of the EPCA. It fulfills the objectives of the Regulations to coordinate the power generation and energy production in the aggregate for all production facilities on the Churchill River to satisfy the delivery requirements of both CF(L)Co and Nalcor, in a manner that provides for the maximization of the long-term energy generating potential of the Churchill River.

4. NEGOTIATION PROCESS

The EPCA contemplates that where two or more persons have been granted rights on the same body of water, they will enter into negotiations to establish a water management agreement. By letter dated March 19, 2009 from Gilbert Bennett, Vice President – Lower Churchill Project, Nalcor to Andrew MacNeill, Vice President and General Manager – CF(L)Co, Nalcor invited CF(L)Co to enter into negotiations towards achieving a water management agreement. This letter is appended as Appendix C.

Both parties assembled negotiating teams comprised of internal staff, complemented by technical and legal advisors. Negotiations proceeded over the course of the spring and summer of 2009. By mid-September, the negotiating teams had developed a proposed agreement. There were no outstanding issues. The agreement that was reached by the negotiating teams is attached as Schedule A to this Application.

Agreements between related parties of CF(L)Co are subject to the terms of a Shareholders' Agreement (Exhibit 9). Nalcor is the parent company of Hydro. Hydro, as one of the shareholders of CF(L)Co, is an affiliate of CF(L)Co. Approval of a contract between related parties of CF(L)Co requires that a special majority decision of the CF(L)Co Board of Directors. At least one director appointed by Hydro and at least one director appointed by Hydro Québec must vote in favour of the decision.

The proposed Water Management Agreement was considered by the CF(L)Co Board of Directors on October 23, 2009, and the approval was not granted. This was confirmed by way of an email from Andrew MacNeill to Gilbert Bennett dated October 27, 2009. This email is appended as Appendix D.

The CF(L)Co Board of Directors declined to provide direction as to changes that might be required to the proposed agreement in order to make it acceptable. Further, CF(L)Co has confirmed that they are not in a position to resume negotiations. Consequently, Nalcor concluded that an application to the Board would be required. Nalcor has therefore applied to the Board to establish the proposed agreement as the terms of a water management agreement.

Andrew MacNeill/cflco/NLHydro
10/27/2009 12:10 PM

To Gilbert Bennett/NLHydro@NLHydro
cc AMacNeil@nlh.nl.ca, Geoff Young/NLHydro@NLHydro, Peter Hickman/NLHydro@NLHydro
bcc
Subject Re: Water Management Agreement

At a meeting of the CF(L)Co Board of Directors on Friday, October 23, 2009, the Board considered, for approval, the draft Water Management Agreement that was negotiated by CF(L)Co and Nalcor Energy and recommended by the CF(L)Co negotiating team. The required Board approval was not achieved. Neither was the Board able to provide any direction as to how the agreement could be modified such that it might receive board approval. The CF(L)Co negotiating team is therefore not in a position to resume negotiations at this time.

Andrew MacNeill
VP& General Manager of CF(L)Co
Executive Leadership
Nalcor Energy - Churchill Falls
t. 709 925-8227 c. 709 685-5254 f. 709-925-8326
e. AMacNeill@nalcorenergy.com
w. nalcorenergy.com

You owe it to yourself, and your family, to make it home safely every day. What have you done today so that nobody gets hurt?

Gilbert Bennett---10/26/2009 05:20:05 PM---Gentlemen: I would like confirmation of the followir

From: Gilbert Bennett/NLHydro
To: Peter Hickman/NLHydro, AMacNeil@nlh.nl.ca@NLHydro
Cc: Geoff Young/NLHydro@NLHydro
Date: 10/26/2009 05:20 PM
Subject: Water Management Agreement

Gentlemen:

I would like confirmation of the following two points regarding water management:

1) whether the CF Board approved the tentative water management agreement, and

2) any issues that were regarded by the Board as deficiencies, problems, or concerns that prevented the Board from approving the tentative agreement.

Thanks in advance,

Gilbert

Gilbert J. Bennett, P. Eng.
Vice President
Nalcor Energy - Lower Churchill Project
t. 709-737-1836 f. 709-737-1782
e. gbennett@nalcorenergy.com
w. nalcorenergy.com
1.888.576.5454

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Oct 4 2013
Sr Hydro

Question: Could you provide a breakdown of the **176 MW increase of existing non- thermal generation** ?

Response:
Hydro does not allocate a specific generation resource to a specific load or region of the Island Interconnected System. The online generation is considered pooled and shared amongst all connected loads at the time. In simple terms Hydro does not "paint" electrons from Bay d'Espoir and dedicate them to say Grand Falls.

In response to your question above in the context of your previous questions, the existing non-thermal generation (non-Holyrood) of interest includes:

Source	Net Capacity (MW)
Newfoundland and Hydro	
Bay d'Espoir	592.0
Cat Arm	126.0
Upper Salmon	84.0
Hinds Lake	75.0
Granite Canal	40.0
Paradise River	8.0
Snook's, Venam's & Roddickton mini-hydros	1.3
Total NL Hydro	**927.3**
Power Purchases	
Star Lake and Exploits Generation	105.8
Corner Brook Cogeneration	15.0
Rattle Brook	4.0
Total Power Purchases	**124.8**
Total Hydroelectric Generation	**1052.1**

The optimal threshold to start the first unit at Holyrood, assuming new Bay d'Espoir to Western Avalon transmission line is constructed, is based upon all Hydro and Power Purchase generation being online (i.e., 1052 MW). To ensure sufficient generation reserve to withstand the loss of the largest hydro-electric unit the available non-Holyrood capacity equals 1052 less 154 or 898 MW. Adding the capacity of available standby generation brings the total available non-Holyrood capacity to 1017.7 MW (i.e. 898 + 114.7 MW). Given the existing distribution of load across the island, a total system load in the 1017 MW range translates to an Avalon load of 495 MW as measured at Hydro's Western Avalon Terminal Station near Chapel Arm.

176 MW

Recall that due to transmission line constraints the existing transmission system limits the transfer of load to 319 MW at Western Avalon Terminal Station leaving existing non-Holyrood generation underutilized.

Hydro Reply Oct 4 2013

What is the current budget for the BDE TL upgrade for the **176 MW** increase in non-thermal generation ?

Hydro is proposing the new 230 kV transmission line between Bay d'Espoir to Western Avalon to ensure power system stability for contingencies on the Island Interconnected Transmission System as part of the transmission system integration projects necessary to ensure satisfactory operation of the Labrador – Island HVdc Link as sanctioned by the provincial government in December 2012. The transmission line addition has a total capital cost estimate of approximately $260 million.

What is the (sic) BDE TL upgrade project schedule?

Once approved by the Public Utilities Board, construction of the Bay d'Espoir to Western Avalon transmission line addition is scheduled to be completed by the end of 2017.