Nova Scotia Utility and Review Board

IN THE MATTER OF

The Maritime Link Act, S.N.S. 2012, c.9
and the
Maritime Link Cost Recovery Process Regulations, N.S. Reg. 189/2012

Maritime Link Project Application

January 28, 2013

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GLOSSARY

20 for 20 Principle:

In exchange for 20 percent of the electricity from Muskrat Falls over the agreed-upon term, NSPML is responsible for 20 percent of the LCP Phase 1 and Maritime Link facilities costs.

Additional Investment:

Emera's investment in the Labrador-Island Transmission Link is part of the Nalcor Transactions. Emera is not seeking regulatory recovery of this investment from customers in Nova Scotia.

AACE Class Engineering Estimate:

Class engineering estimates are a means of describing the maturity of an estimate. The Association for the Advancement of Cost Engineering Classification system uses classes of cost estimates with Class 5 being the least mature, equivalent to a concept screening, and Class 1 being the most mature, with all project parameters defined and detailed unit costing. *Source: AACE international Recommended Practice No. 18R-97.*

Decision Gate:

The Maritime Link Project follows a structured approach to project management which is a recognized best practice for the review and approval of major capital projects in many industries. The approach uses project phases and Decision Gates at which completed work is reviewed before the project is allowed to progress to the next stage of development. The activities of each Project phase provide the necessary deliverables and information to support management's decision to proceed through to the next phase of work. Key decision points are represented by Decision Gates that must be passed before the next phase of the project may begin.

Dispatchable:

Describes the ability of a utility to call upon a generating unit when the utility needs more or less electricity to adjust its output.

Lower Churchill Projects Phase One (LCP Phase 1):

The three projects of the Lower Churchill Projects Phase One development are as follows,

Muskrat Falls Generation Station - Nalcor ownership

Labrador Transmission Assets (LTA) - Nalcor ownership

Labrador-Island Transmission Link (LIL) - Nalcor controlling ownership with some investment by Emera

Maritime Link (or Maritime Link facilities):

A new, high-voltage direct current transmission system and related components, including grounding systems, and includes:

1. Direct current converter stations in Newfoundland and Labrador; and in Cape Breton, Nova Scotia, together with the subsea cables and high voltage direct current transmission lines connecting the converter stations;
2. an alternating current transmission line connecting the converter station in Newfoundland and Labrador with the Newfoundland Island Interconnected System, and;
3. any additional transmission infrastructure required in order to interconnect with the Newfoundland Island Interconnected System and the Nova Scotia Transmission System.

Maritime Link Project:

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.

Nalcor Surplus Energy

Electricity originating at Nalcor, not part of the Nova Scotia Block, that requires NSPML to facilitate transmission through Nova Scotia and New Brunswick according to the terms of the Nova Scotia Transmission Utilization Agreement (NSTUA) and New Brunswick Transmission Utilization Agreement (NBTUA).

Nalcor Transactions:

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 the agreement 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 [Nova Scotia],
- iv) the granting of transmission rights over the Maritime Link,
- v) the responsibility for operating and maintaining the Maritime Link, and
- vi) the transfer of the Maritime Link to Nalcor Energy following a period of 35 years after energy is first delivered to Emera.

  The Nalcor Transactions are described in Section 2 of this Application. The commercial agreements reflecting the Nalcor Transactions are summarized in Appendix 2.01 and can be found in Appendices 2.02 to 2.16.

Nova Scotia Block (NS Block):

- a) the Energy entitlement of Emera from the Muskrat Falls Plant to be taken on a calendar year basis (and pro-rated during the first and last calendar years of the initial Term if necessary to reflect the date on which First Commercial Power occurs), calculated to be 0.986 TWh (July 31, 2012) of energy annually (such quantity to be finally determined in accordance with Schedule 2 of the Energy and Capacity Agreement); and
- b) Supplemental Energy,

  both quantities referred to in paragraphs (a) and (b) are less Emera's proportionate share of Transmission Losses; and
- c) a monthly addition or subtraction of the ECA Loss Adjustment and the NSTUA Losses Adjustment, as applicable; and

d) the Associated Capacity entitlement of Emera which is provided to enable delivery of Energy referred to in paragraphs (a) and (b) during the hours specified in the ECA.

Project Costs:

All costs incurred by an applicant in connection with the Maritime Link Project.

Sanction:

Final approval by a party to proceed to commencement of construction of the Maritime Link as evidenced by the passing of a resolution by the board of directors of such party, authorizing the party to undertake activities, enter into contractual obligations, and incur costs as required for the purposes of the completion of the development activities.

Supplemental Energy:

The supplemental amount of Energy, if any, to be determined by Nalcor in accordance with Schedule 4 of the ECA, that will be Scheduled and delivered by Nalcor to Emera at the Delivery Point (and for greater certainty is an amount net of Transmission Losses) for the five-year period commencing at First Commercial Power.

1.0 INTRODUCTION AND APPROVAL REQUESTED

The Maritime Link Project is the lowest long-term cost alternative that meets all legislative requirements described in Section 5 (1) (b) of the *Maritime Link Act*[1] (Act). In addition to costing less for Nova Scotia customers than any other alternative, the Maritime Link Project will provide new options for the long-term energy requirements of customers in Nova Scotia. No other potential solution can deliver these benefits.

This section introduces the application and explains the purpose and reasons for the Maritime Link Project and the scope of the approvals sought. A summary of the benefits of the Maritime Link Project is provided, and the specific relief sought is described, all as required by the *Maritime Link Cost Recovery Process Regulations*[2] (Regulations).

1.1 Introduction

This is an application by NSP Maritime Link Incorporated, (NSPML) to the Nova Scotia Utility and Review Board (UARB or Board) for approval of the Maritime Link Project (sometimes, the Project) and a plan to recover all Project Costs, including those related to building and operating the Maritime Link, pursuant to the *Maritime Link Act* and the *Maritime Link Cost Recovery Process Regulations* made under Section 6 of the Act.

NSPML, an indirect wholly owned subsidiary of Emera Inc. (Emera), and an affiliate company of Nova Scotia Power Inc. (NS Power), is the Applicant and the entity through which the Maritime Link Project will be developed and constructed. This separate business entity enables the Maritime Link Project to meet financing requirements for a Federal Loan Guarantee which will save more than $100 million on a net present value basis for Nova Scotia's electricity customers.

[1] S.N.S. 2012, c. 9
[2] N.S. Reg. 189/2012

The Act vests the UARB with general supervision of NSPML and the Maritime Link Project, and the Regulations have been made, *inter alia*, to establish the criteria and conditions by which the Maritime Link Project is to be reviewed and considered for approval by the UARB.[3]

In turn, the Regulations direct the UARB to approve the Maritime Link Project if it is satisfied that the Project meets all 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.[4]

1.2 The Maritime Link Project and the Maritime Link Facilities

The Maritime Link Project refers to the design, construction, operation and maintenance of the Maritime Link transmission facilities, including a high-voltage direct current (HVDC) subsea cable, 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, as set out in a term sheet between Emera and Nalcor Energy (Nalcor) in November 2010.[5]

The new transmission infrastructure consists of proven equipment in configurations that have been proven to deliver reliable and dependable service. These systems, as proposed for the Maritime Link, are common in applications throughout the world and exist in various configurations that include higher transfer capabilities, longer and deeper subsea

[3] *Maritime Link Act*, Sections 4 and 6(1)
[4] Regulation, Subsection 5(1)
[5] See Subsection 2(c) of the Act. The Term Sheet is provided as Appendix 1.02

cables and higher operating voltages.[6] For example, Figure 1-1 indicates similar applications in Europe.

Figure 1-1 – Other HVDC Applications – Similar to Maritime Link[7]

As an integral part of the Maritime Link Project, the Maritime Link will interconnect the Nova Scotia transmission system with that of Newfoundland and Labrador. The

[6] See Figure 3-6 in Subsection 3.4
[7] See Figure 3-6 in Subsection 3.4

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, including near-shore grounding stations, direct current conversion stations, transmission lines, and substation improvements.[8]

The underlying rationale for the Project is addressed in various parts of this Application. In summary, the Maritime Link Project will give Nova Scotia access to reliable, renewable energy at a predictable price from Phase 1 of Nalcor's Lower Churchill hydroelectric development in Labrador (Lower Churchill Project Phase 1 or LCP Phase 1), will allow Nova Scotia to meet new Federal regulatory requirements focused on greenhouse gas (GHG) emission reductions and will assist in meeting Nova Scotia's *Renewable Electricity Standards.*

The principal elements of the LCP Phase 1 and the Maritime Link are shown in Figure 1-2.

A thorough description of the Maritime Link facilities is provided in Section 3 of the Application. Figure 1-3 shows the facilities in some greater detail: overland sections of the HVDC line in dark red, subsea sections of the HVDC line in grey, overland sections of the HVAC (high-voltage alternating current) line in light red, grounding lines in blue and the transition compounds, grounding and converter sites.

1.3 Reasons for the Maritime Link Project

The Maritime Link Project is being undertaken in the context of increasing concern about the environmental impacts of fossil fuel consumption. Increasingly stringent federal regulations limit emissions from electricity generation. This requires more generation from renewable sources. Nova Scotia's electrical system is in the process of transforming the way it generates electricity and the Maritime Link Project provides greater access to

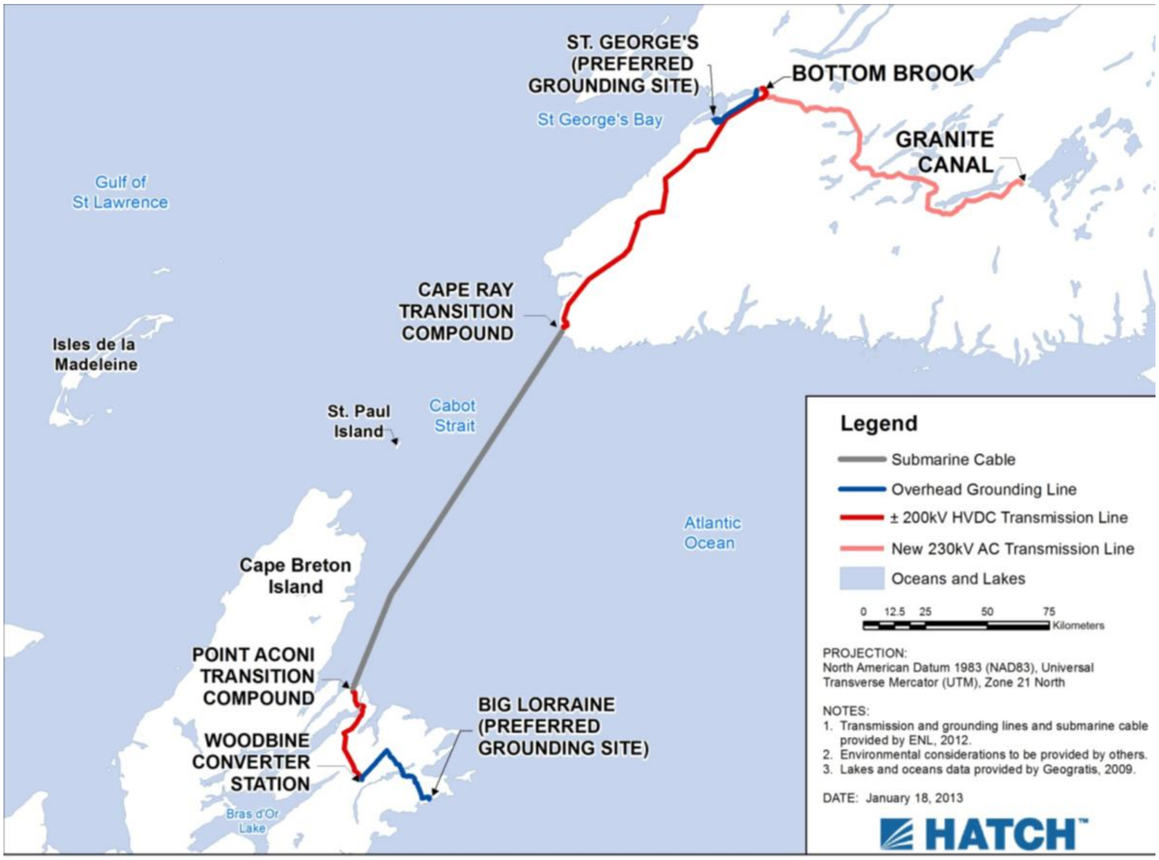
[8] See Subsection 2(b) of the Act

clean hydroelectric power. Customers will also benefit from greater stability and predictability in energy prices.

Figure 1-2 Regional Energy Development

The Maritime Link Project also offers an historic opportunity to enhance Nova Scotia's access to a variety of future electrical energy options, by greatly strengthening the province's connection to the North American electricity grid, thus improving access to electricity markets. For the first time in its history, the Maritime Link Project positions Nova Scotia in the middle of an electricity market, and no longer at the end of transmission lines with limited market access.

Figure 1-3 The Maritime Link



Once completed, the Project will also increase Nova Scotia's capacity to develop new intermittent sources of electricity, such as wind, and incorporate them in the Nova Scotia's electrical transmission system. This flexibility will benefit electricity customers in Nova Scotia above and beyond the intrinsic benefit of a new, reliable source of clean, renewable energy at stable prices.

1.4 Lowest Long-term Cost Alternative

A thorough alternatives analysis is provided in Section 6 of this Application and demonstrates that the Maritime Link Project is the lowest long-term cost alternative for electricity for Nova Scotia electricity customers, that will meet existing provincial and recently proclaimed federal environmental legislation and associated agreements. Additionally, of the available alternatives, only the Maritime Link Project:

- increases rate predictability for electricity customers through long-term (35 year) fixed cost contract,
- provides greater long-term electricity security,
- offers a strategic transformational opportunity for enhanced access to competitive markets,
- offers access to large, new, renewable electricity supplies for a minimum of 50 years,
- offers specific quantities of renewable energy at a stable cost for 35 years
- provides enhanced reliability,
- strengthens Nova Scotia's connection to the North American grid to prepare for and to take advantage of many future energy scenarios,
- supports the development of additional intermittent renewable energy resources in Nova Scotia, such as wind and tidal.

1.5 The Reality of Limited Access to Electricity Markets

For most of the last century, Nova Scotia has been a virtual electrical island, obligated to be self-sufficient in electricity with only limited ability to import electricity from the North American grid over a single intertie to New Brunswick. Until now, there was no compelling economic or network stability reason to enhance the interconnection to the North American grid. With reliable and economic supply within Nova Scotia and an absence of long-term, low-cost sources of imported electricity, customers in Nova Scotia have experienced competitively priced and reliable service from their utility, although subject to the volatility of international commodity prices for coal and other fossil fuels, which has been particularly challenging in recent years.

In the earliest years of Nova Scotia's electric system, most of the province's generation came from its hydroelectric resources, supplemented by some oil and coal. As demand outstripped production from hydro, the province's electric utilities came to depend on oil. When the 1973 OPEC oil embargo led to rapid increases in the price of oil, the cost of electricity in Nova Scotia rose dramatically. In 1977, average electricity rates increased by 44 percent, followed by increases of 17 percent in 1978 and 12.5 percent in 1979, the first year that the Lingan coal generating station came online in Nova Scotia.

In response, the province switched to generation fired by indigenous Nova Scotia coal, a less expensive resource at the time, which also supported employment in the province. This contributed to a period of relatively stable prices in the final decades of the twentieth century**.** By the turn of the century, however, the last of Nova Scotia's major coal mines closed, which required that coal had to be sourced from international markets. This limited the potential to generate electricity from indigenous resources. Moreover, Federal regulations require all coal fired generation to be phased out, starting this decade.

At the same time, public concern about the environmental impacts associated with coal-fired generation led to increasingly stringent environmental regulations. To meet these concerns, NS Power has been adding renewable electricity (wind and biomass) to the generation mix, and using more natural gas when it is economic to do so. This careful and incremental approach to the generation portfolio provides flexibility to respond to changing environmental obligations, and to take advantage of opportunities as they arise, such as the Maritime Link Project.

Most of Nova Scotia's potential for hydroelectricity has been fully developed, and the economic opportunities for natural gas generation have been captured to date. Since

1999, Nova Scotia has had the ability to use natural gas to produce electricity when economically advantageous for customers. The utility captured opportunities to use natural gas to benefit customers through additional economic generation and, for a time, by selling excess gas in order to lower overall costs to customers. In 2011, 20 percent of NS Power's electricity was generated from natural gas.

Nova Scotia has additional potential for wind generation, but because wind energy is intermittent, it requires additional energy sources for backup. Tidal energy's vast potential has not yet approached commercial development, and once it does, it too will require backup or storage given the fluctuating generating capacity.

Despite efforts to increase hydroelectricity, wind and natural gas generation, there has not been, until now, an economically attractive long-term base load emissions-free electricity source to meet the needs of Nova Scotia electricity customers. That source is the Nalcor electricity from Lower Churchill via the Maritime Link Project.

If the first century of electricity generation in Nova Scotia demonstrates anything, it is the value of flexibility and diversification. Reliance on a single energy source leaves customers vulnerable when supplies tighten, and market conditions are not favourable. This has happened to Nova Scotia in the past. Mitigating this risk is a key advantage of the Maritime Link Project. To limit the price volatility associated with a single fuel such as natural gas or imported coal, the logical course is to continue diversifying Nova Scotia's energy sources. The Maritime Link Project meets Nova Scotia Power's need for a renewable energy source to comply with environmental requirements in the most cost effective manner over the long-term, providing a hedge against rising fuel prices for between 8 and 10 percent of Nova Scotia's electricity needs.

1.6 Environmental Legislation

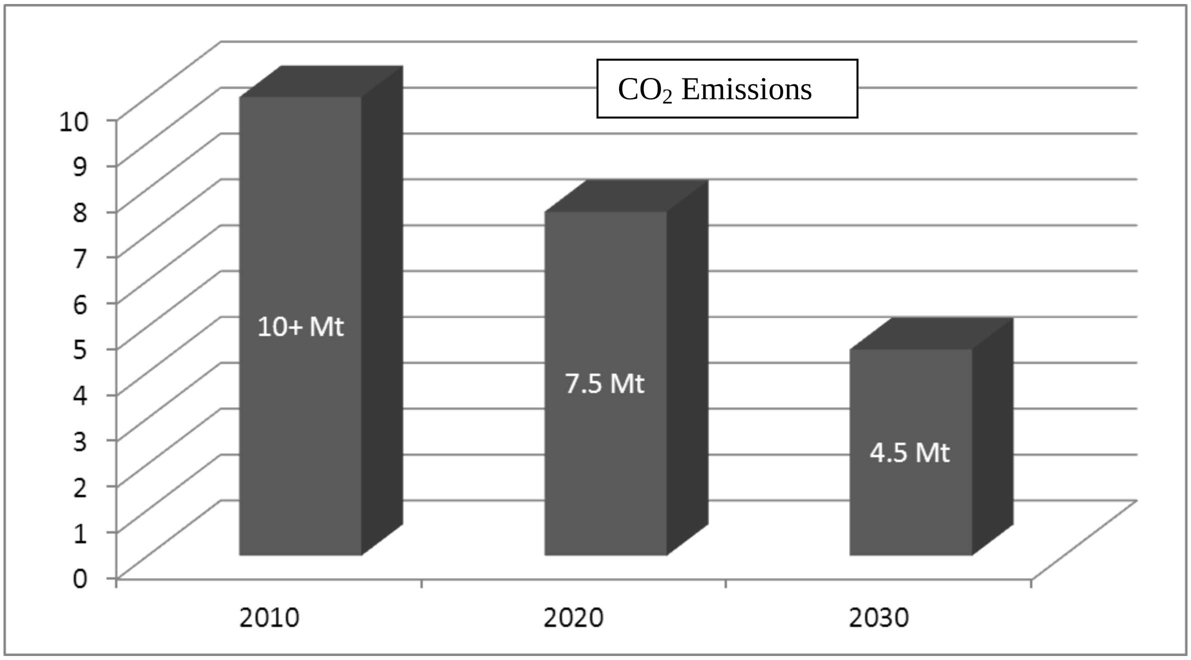
Shifting Nova Scotia's electricity generation mix to include more clean energy sources will benefit the environment, increase energy security, and help manage long-term costs. Nova Scotia, which currently depends on imported fossil fuels, is taking part in a transformation from using carbon dioxide intensive, volatile fuels to clean, stable renewable energy.

In 2005, the Government of Canada added carbon dioxide (CO_2) to the Canadian Environmental Protection Act's list of toxic substances,[9] and began work on a federal framework for reducing greenhouse gas (GHG) emissions from electricity generation. Provincial regulations already in place require a 25 percent reduction (2.5 megatonnes) from 2010 levels by 2020. New federal regulations, proclaimed in September 2012, require an additional 3.0 megatonnes reduction in Nova Scotia's GHG emissions in Nova Scotia by 2030.[10] This is depicted in Figure 1-4.

[9] Environment Canada, CEPA Environmental Registry, Toxic Substances List – Schedule 1. Carbon Dioxide is number 74 on the list. https://www.ec.gc.ca/lcpe-cepa/default.asp?lang=En&n=0DA2924D-1&wsdoc=4ABEFFC8-5BEC-B57A-F4BF-11069545E434

[10] Canada Gazette, Vol. 146, No. 19, September 12, 2012, Reduction of Carbon Dioxide Emissions from Coal-fired Generation of Electricity Regulations, pages 1951-2091. http://www.gazette.gc.ca/rp-pr/p2/2012/2012-09-12/pdf/g2-14619.pdf

Figure 1-4: Carbon Dioxide (CO_2) Emission Limits



1.7 Introduction to the Nalcor Commercial Transactions

NSPML is the Emera subsidiary responsible for building and operating the Maritime Link. Nalcor is the provincial Crown Corporation responsible for managing Newfoundland and Labrador's energy resources.

The November 2010 Term Sheet established the key principles to bring energy from Lower Churchill to customers in Newfoundland and Labrador, Nova Scotia and beyond. The Term Sheet outlined the terms and conditions to develop LCP Phase 1 and the Maritime Link facilities, the financial aspects of the Nalcor Transactions and the steps to complete formal, detailed commercial agreements.

On July 31, 2012, Emera and Nalcor along with the Governments of Nova Scotia and Newfoundland and Labrador, executed 13 agreements (collectively called the Nalcor Transactions) pertaining to the development and transmission of hydroelectric power from Muskrat Falls, on the Churchill River in Labrador, to the Island of Newfoundland, the Province of Nova Scotia and through to New England. The agreements relate to the development of the Muskrat Falls generating station, the Labrador Transmission Assets, the Labrador-Island Transmission Link and the Maritime Link. These agreements are provided as Appendices 2.02 to 2.14.

The execution of these agreements was followed, on November 30, 2012, with a Federal Loan Guarantee term sheet between the Governments of Canada, Nova Scotia and Newfoundland and Labrador, as well as, Nalcor and Emera (Appendix 4.03). Subsequently, the Newfoundland and Labrador legislature voted in favour of a bill to approve the Muskrat Falls Generation Station, the Labrador Transmission Assets and the Labrador-Island Transmission Link projects on December 5, 2012.

On December 17, 2012, Emera and Nalcor entered into a Sanction Agreement (Appendix 2.15) enabling both parties to advance their respective projects, and a Project Oversight Agreement (Appendix 2.16).
This now sets the stage for construction to begin on the Muskrat Falls generating station, the Labrador Transmission Assets and the Labrador-Island Transmission Link, as well as, this regulatory filing with the UARB for the Maritime Link Project.

When these collective Project Costs (including capital costs, operating and maintenance, return on equity, interest and, income taxes) are compiled, a revenue requirement is determined in the post-construction period. NSPML has prepared a detailed financial model that provides the forecast of all such costs during both the construction and operating periods – extending to 35 years post construction. The results of this model are contained in Appendix 4.01.

In addition, in determining the net costs of the Maritime Link Project to Nova Scotia customers, there are the added benefit of fuel cost savings in NS Power relating to the NS Block and the additional market priced electricity, as well as, the access to additional market priced electricity itself, as a result of the Maritime Link Project being in service.

The net impact to Nova Scotia customers is a blending of the Project Costs with the purchase of market priced electricity and related fuel savings of both the NS Block and market priced electricity in NS Power. This additional market priced electricity may be purchased either from Nalcor (Nalcor Surplus Energy) or from other energy providers. The net cost of electricity assumes that on average NS Power has purchased approximately 2 TWh per year of additional market priced electricity and the displacement of NS Power fuel costs. Additional information on this purchase is provided in Section 6.

Consistent with the underlying concept of the Nalcor Transactions, the capital costs of the Maritime Link Project will equal 20 percent of the estimated capital costs of all projects contained in the LCP Phase 1 and Maritime Link facilities. This amount and the approval requested by NSPML, is estimated to be $1.52 billion with a variance of $60 million, as described in detail in Section 4. As is outlined in Section 6, this represents the lowest long-term cost alternative for Nova Scotians which would meet applicable environmental and legislative requirements.

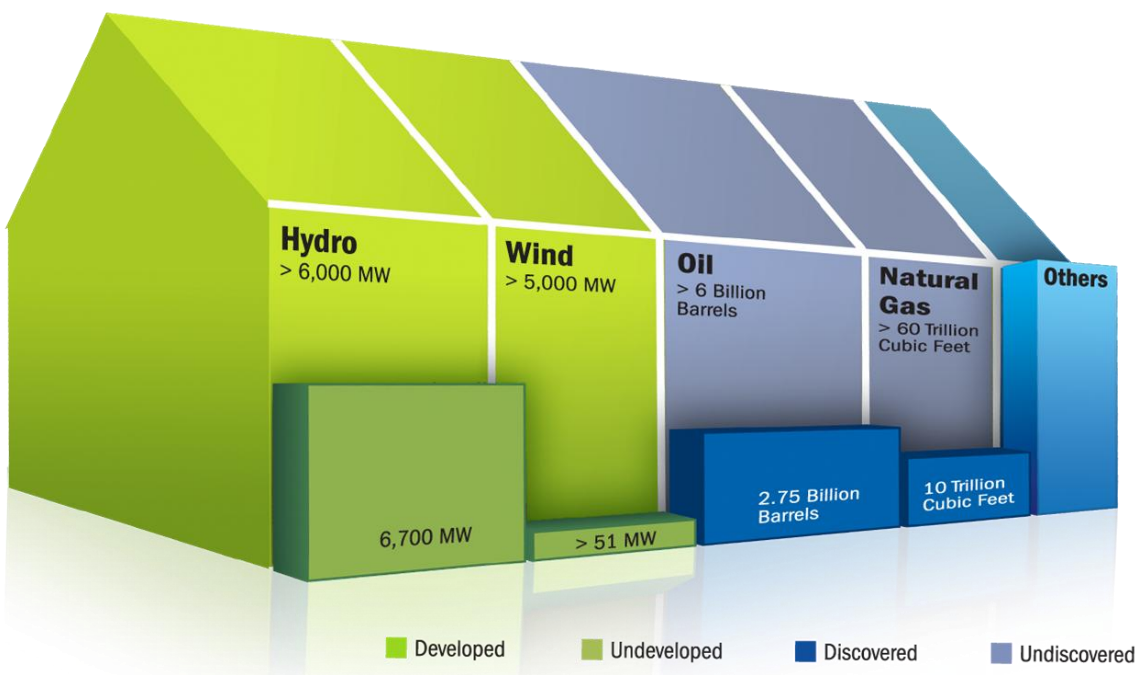
1.8 Accessing Cleaner, More Reliable Energy

NS Power will have contractually guaranteed annual access to 170 MW of on-peak renewable electricity (plus a supplemental amount of electricity in the first five years of operation – as described in Section 2), and the opportunity to purchase additional amounts of economically priced electricity. Because hydroelectric generators do not use fuel, emissions will be negligible. Moreover, this renewable hydroelectricity will displace coal and other carbon dioxide-emitting fossil fuel generation. Electricity from Muskrat Falls will be dispatchable,[11] meaning NS Power can plan to use it at times when alternative sources would be more expensive.

[11] Flexibility to move up or down by 40 MW. Profile can be optimized during the 16 hour, on- peak period and can be scheduled in 30 minute increments.

Over the long-term, the Maritime Link Project gives Nova Scotia a path to Newfoundland and Labrador's energy supply potential. As Figure 1-5 illustrates, Newfoundland and Labrador has only begun to develop its full energy potential. It has developed 6,700 MW of hydro, and has at least another 6,000 MW available for development. It has developed only 51 MW of wind energy, but has the potential to develop another 5000 MW or more. Moreover, the two energy sources complement each other, since the availability of dispatchable hydro power will help overcome wind's drawback, its intermittent nature. Nalcor has advised NSPML that it plans to develop more hydro and wind generation and use the Maritime Link to transmit that electricity to market.

Figure 1-5 Newfoundland and Labrador's Energy Warehouse[12]



Source: Government of Newfoundland and Labrador

[12] "Focusing on Our Energy, Newfoundland and Labrador Energy Plan", http://www.nr.gov.nl.ca/energyplan/energyreport.pdf

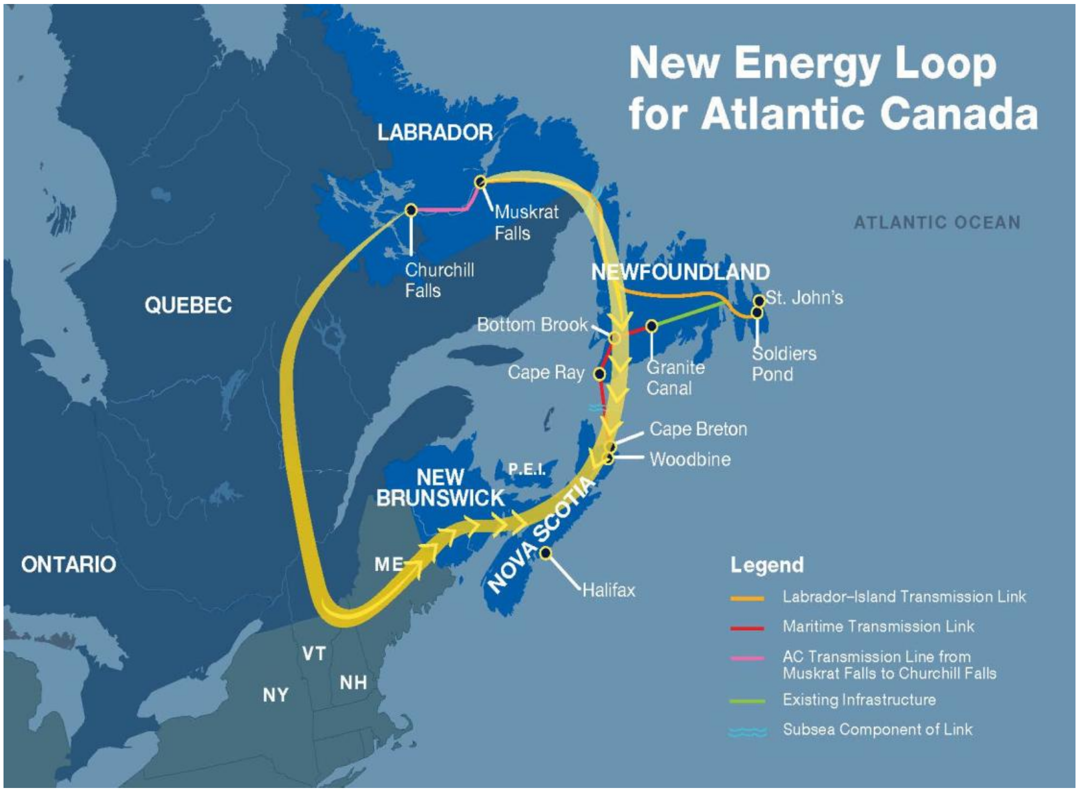
Newfoundland and Labrador's 30 TWh (Terawatt-hours) per year are currently committed under the Upper Churchill Falls contract. When that contract ends in 2041, some of this electricity will potentially become available to Nova Scotia.

The Project not only assures Nova Scotia access to a growing supply of reliable renewable energy, it also creates a new regional electricity loop that gives access to competitive energy markets. Nova Scotia will be connected to Newfoundland and Labrador and consequently to the North American electricity grid via the Labrador Transmission Assets. This loop will be completed through an existing path through New Brunswick to New England. This is illustrated in Figure 1-6.

Through multiple interconnections and greater access, Nova Scotia Power will have new opportunities to buy electricity at market prices. This will help reduce Nova Scotia Power's future exposure to the volatility of imported coal prices.

The dispatchable nature of the energy delivered through the Maritime Link offers Nova Scotia Power customers yet another benefit. It will support further development of intermittent renewable energy sources such as wind and eventually tidal power, by serving as an additional backup supply.

Figure 1-6 New Energy Loop for Atlantic Canada



The Maritime Link Project will have a significant positive environmental impact on Nova Scotia. The energy that electricity customers in Nova Scotia receive under the Nalcor Transactions will:

- Reduce NS Power's emissions, cumulatively equivalent to 80-120 megatonnes of carbon dioxide in Nova Scotia due to the Maritime Link.

- Reduce imported coal consumption by 400,000 tonnes per year or more.

- Help NS Power meet the 50 percent reduction in carbon dioxide emissions required by the new regulations under the *Canadian Environmental Protection Act* by 2030[13].

1.9 Ideal Time to Finance

Designing and building a Project of this magnitude requires major capital investment and financing. Current low interest rates make this an ideal time to move the Project forward. Low interest rates reduce the cost of debt, which in turn lowers the cost to Nova Scotia customers.

The support of the Government of Canada via a loan guarantee is a unique and important feature of the Maritime Link Project that will directly benefit Nova Scotia customers and reduce the cost of the Maritime Link Project by more than $100 million on a net present value basis.

1.10 Request for Approval

Section 5(5)(a) of the *Maritime Link Cost Recovery Process Regulations* requires NSPML to include a statement of the specific relief requested by the applicant. This section contains that specific request.

NSPML respectfully requests Board approval of the Maritime Link Project and Nalcor Transactions and related transactions, in accordance with the *Maritime Link Cost Recovery Process Regulations* made pursuant to the *Maritime Link Act* on the basis of this Application as filed.

[13] Canada Gazette, Vol. 146, No. 19, September 12, 2012, Reduction of Carbon Dioxide Emissions from Coal-fired Generation of Electricity Regulations, pages 1951-2091. http://www.gazette.gc.ca/rp-pr/p2/2012/2012-09-12/pdf/g2-14619.pdf

The Maritime Link Project is the outcome of a lengthy period of dialogue and negotiation between Emera and Nalcor, involving as well the governments of Canada, Nova Scotia, and Newfoundland and Labrador. The Maritime Link Project is presented for Board approval as a complete package within the context of the Nalcor Transactions, related transactions and the development of the Lower Churchill hydroelectric system. NSPML notes that some of the components of the Maritime Link Project, Nalcor Transactions and related transactions may be items that in and of themselves would not normally be approved by the Board due to being operational in nature or decisions that are within the authority of a regulated utility to make without Board approval. Each element of the Nalcor Transactions and related transactions is integral to the success of the whole and of the Maritime Link Project and therefore NSPML requests that the Board's approval of the Maritime Link Project include all of its components, as filed**.**

NSPML submits that the transactions contemplated by and set forth in the formal agreements, copies of which are attached to this Application as Appendices 2.02 through 2.16 inclusive plus Appendices 8.01 and 8.03 constitute "related transactions" as referred to in the definition of "Maritime Link Project" set forth in the *Maritime Link Act* and that such formal agreements set forth in Appendices 2.02 through 2.16, inclusive, constitute "agreements between Emera and Nalcor Energy" as referred to in the definition of "Nalcor Transactions" in the *Maritime Link Cost Recovery Process Regulations*. NSPML requests the Board's confirmation of this and that approval by the Board of the Maritime Link Project constitutes approval of the Maritime Link Project inclusive of all such transactions.

In this context, NSPML respectfully requests that the Board grant an order or orders:

i) Approving the Maritime Link Project, as described in the Act and this Application, pursuant to Section 5 of the Regulations, and confirming that the transactions contemplated by the formal agreements, copies of which are attached to this Application as Appendices 2.02 through 2.16, inclusive, plus Appendices 8.01 and 8.03 constitute the "related transactions" referred to in the definition of "Maritime

Link Project" set forth in the *Maritime Link Act* and further confirming that the formal agreements set forth in Appendices 2.02 through 2.16, inclusive, constitute the "agreements between Emera and Nalcor Energy" referred to in the definition of "Nalcor Transactions" in the *Maritime Link Cost Recovery Process Regulations*. The transactions contemplated by and contained in such formal agreements and related transactions include without limitation:

(a) Maritime Link Joint Development obligations, including interconnection and transmission operating requirements for the Maritime Link

(b) Energy and capacity obligations, including scheduling and delivery of the Nova Scotia Block

(c) Transmission service and utilization obligations, including, without limitation

  a. the provision of Firm and Conditional Firm transmission service within Nova Scotia to Nalcor;

  b. the recovery of the costs associated with the transmission through Nova Scotia of Nalcor Surplus Energy, as costs of the Maritime Link Project, and an integral part of the Nalcor Transactions, including in particular those costs billed to NSPML by NS Power due to any variance between revenues recovered from the Nalcor transmission fees and the redispatch, capital expenditure and system maintenance costs, which can be recovered by NSPML in the assessment to be set against NS Power; and

  c. the ability under the Agency and Service Agreement to put Muskrat Falls electricity to NS Power in the event transmission is not available through New Brunswick, at a cost to NS Power equivalent to the avoided cost to NS Power of backing down the applicable amount of generation or alternative import.

(d) Interconnection operator obligations, including compliance with reliability standards for interconnected transmission and bulk power systems

(e) Joint operations obligations, including the use of Good Utility Practice in the operation and long-term maintenance of the Maritime Link;

In addition, and for greater certainty, the Applicant requests that the order of the Board include:

(f) Acknowledgment that the Muskrat Falls Generation Station, the Labrador Transmission Assets, and the Labrador-Island Link are not part of the Maritime Link Project and are not regulated by the UARB;

(g) Approval of the sale of the Maritime Link to Nalcor and the sale of the Woodbine Upgrades to NS Power, following a period of 35 years after energy is first delivered to NSPML,

(h) Confirmation that any one time operating and maintenance cost true-up payment pursuant to the Joint Operations Agreement shall constitute a Project Cost

ii) Approving the Project Costs of $1.52 billion for the Maritime Link Project as set out in this Application, including without limitation the 20 for 20 Principle

iii) Approving the capital structure, the rate of return on equity, and treatment of AFUDC as requested in Section 4 of the Application, pursuant to Section 5 of the Regulations;

iv) Approving a variance of $60 million with respect to the approved cost of the Project, as defined and requested in the Application, pursuant to Section 6 of the Regulations;

v) Directing that NSPML is entitled to recover the approved costs of the Project via a rate, toll charge or other compensation from NS Power, pursuant to Sections 4 and 8 of the Regulations;

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;

vii) Acknowledging that upgrades on Nova Scotia’s transmission system may be necessary to meet obligations under the Nalcor Transactions as part of the Nova Scotia Transmission Utilization Agreement (NSTUA);

viii) Confirming that:

(a) NS Power's Code of Conduct governing affiliate transactions (Affiliate Code) was created before, and not in contemplation of, the *Maritime Link Act* and Regulations,

(b) The sections of the Affiliate Code which conflict with the Maritime Link Project, the Nalcor Transactions and this Application shall not apply, and

(c) the Maritime Link Project, Nalcor Transactions and related transactions otherwise comply with the NS Power Code of Conduct for Affiliate Transactions;

ix) Confirming that the Maritime Link Project and Nalcor Transactions are supported by a reasonable and comprehensive set of commercial agreements; and

x) For such other relief as may be necessary to give effect to the foregoing, the Application, the Act and the Regulations.

2.0 NALCOR COMMERCIAL TRANSACTIONS

The Regulations[14] require that a summary of the commercial transactions with Nalcor, as well as, copies of all relevant agreements be provided as part of the application. This section of the Application discusses the Nalcor Transactions and a summary of the agreements is found in Appendix 2.01. Copies of the relevant agreements are included as Appendices 1.02, 2.02 to 2.16, 8.01, and 8.03.

In November 2010, Emera and Nalcor Energy executed a Term Sheet to bring electricity generated at Muskrat Falls to consumers in Newfoundland and Labrador, Nova Scotia, and beyond.

The Term Sheet outlined the terms and conditions to develop Phase 1[15] of Newfoundland and Labrador's Lower Churchill hydro resource and the Maritime Link, the commercial terms of the transaction between Nalcor and Emera, and the steps required to complete formal, detailed commercial agreements. On July 31, 2012, Emera and Nalcor executed the formal agreements that implement and supersede the Term Sheet. The agreements have been publicly available since that time, including on the company's website.[16]

2.1 Structure

The principle is that NSPML will pay 20 percent of the LCP Phase 1 and the Maritime Link facilities' estimated total capital and operating costs, and will receive 20 percent of the estimated energy and capacity from Muskrat Falls. This 20 percent energy and capacity is called the Nova Scotia Block (NS Block). In effect, the arrangement places

[14] Paragraph 5(5)(b)
[15] Phase 2 of the Lower Churchill Project is the development of Gull Island. Phase 2 is not contemplated by the agreements between Emera and Nalcor.
[16] www.emeranl.com/en/home/ourbusiness/LowerChurchillAgreements.aspx

NSPML in a similar position to what it would occupy if it had a 153 MW hydro facility[17] available.

The NS Block, estimated to be 895 gigawatt hours per year, will be delivered to Nova Scotia. This amount of energy is equal to 8 to 10 percent of NS Power's current electricity sales to customers. The NS Block is dispatchable, which means the utility can schedule and optimize when the energy is to be delivered to Nova Scotia within the terms of the Energy and Capacity Agreement.[18] The electricity will be delivered during times of peak electricity use, when it is most valuable. Figure 2-1 describes the delivery of the NS Block and Supplemental Energy.

NSPML will develop, own, and operate the Maritime Link, at a total Project estimated capital cost of $1.52 billion plus a variance of $60 million.

Figure 2-1 Energy Delivery Features

Energy	Net Delivered Capacity to NS	Deliveries by week	Seasonality	On Peak/ Off Peak
NS Block	153 MW	16 hours per day x 7 days per week	All year	On Peak
5-Year Supplemental Energy	Approx. 200MW	8 hours per day x 7 days per week	Winter only	Off Peak

The expected service life of the Maritime Link facilities is 50 years. NSPML will own the Maritime Link facilities for the first 35 years and the terms of the agreement with Nalcor provide that Nalcor will provide NSPML with an additional block of electrical energy in

[17] The facility is estimated to be 153 MW because it is 170 MW at the Muskrat Falls Generation Station less the line losses that are calculated from Labrador to Woodbine, NS.
[18] See Schedule 5 of the Energy and Capacity Agreement in Appendix 2.03

the first 5 years of operation of the Maritime Link facilities. This additional electrical energy is known as Supplemental Energy. 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. More details on this calculation are contained in Section 4. In other words, Nova Scotia will receive more energy up front to make up for the energy it won't receive in the last 15 years of the Maritime Link facilities' expected service life. At the same time, Nalcor will be responsible for the maintenance costs of the Maritime Link facilities after NSPML conveys it to Nalcor at the end of the 35 years of operation.

After 35 years, ownership will transfer to Nalcor and the connection will continue to provide benefits and opportunities for Nova Scotians. This second connection to the North American grid will continue to exist, and Nova Scotia will be in a position to negotiate electricity purchases from multiple sources.

Newfoundland and Labrador will regain control of the energy from Upper Churchill Falls in 2041, providing that province with over 5,000 MW in additional hydro resources for which it will need customers. Nova Scotia will be a prime candidate for some of that energy.

In order to access markets in the Maritimes and beyond, Nalcor requires transmission access through Nova Scotia for the 50-year period. The details of this arrangement are set out in the Nova Scotia Transmission Utilization Agreement (NSTUA). NS Power and NSPML have signed an Agency and Services Agreement that describes how NS Power will fulfill the requirements of the NSTUA once the Maritime Link Project is approved. That agreement is provided in Appendix 8.01.

In addition to transmission access through Nova Scotia, the commercial agreements also require Emera to provide Nalcor with a transmission path through New Brunswick and into New England, allowing Muskrat Falls' energy to reach markets in the Northeastern

United States. These provisions are described in the New Brunswick Transmission Utilization Agreement (NBTUA) and the MEPCO[19] Transmission Rights Agreement (MEPCO TRA), respectively.

In the short term, Emera will provide the path through New Brunswick to the US border, using transmission rights attached to its Bayside Generating Station in Saint John. Eventually, Emera, in conjunction with New Brunswick, may develop a new transmission line through New Brunswick.

Emera is investing in the Labrador-Island Transmission Link. This part of the Nalcor Transactions is called the Additional Investment. Emera is not seeking regulatory recovery of this investment from customers in Nova Scotia.

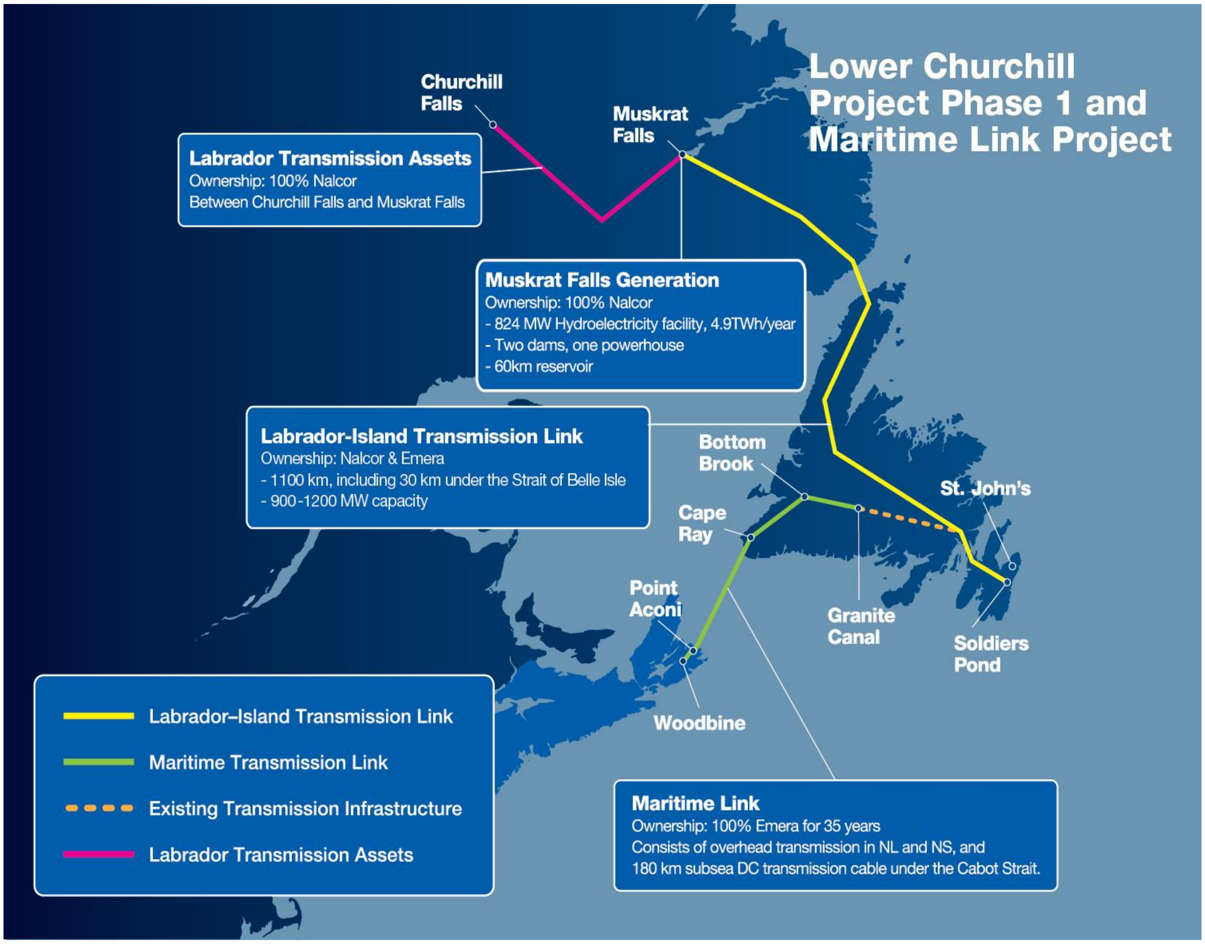
2.2 Economics of the Transaction

The principle is that NSPML will pay 20 percent of the total estimated LCP Phase 1 and Maritime Link facilities' capital and operating costs in exchange for 20 percent of the estimated energy of Muskrat Falls. NSPML is seeking recovery of these costs from customers in Nova Scotia in exchange for providing Muskrat Falls energy to Nova Scotia customers. More details on these costs are contained in Section 4.

In total, Emera's investment in the Maritime Link and the Labrador-Island Transmission Link projects will equal 49 percent of the transmission components of LCP Phase 1 and the Maritime Link facilities. Ownership of the individual components breaks down as shown in Figure 2-2.

[19] Maine Electric Power Company, Inc.

Figure 2-2 Lower Churchill Project Phase I



- Nalcor will own 100 percent of the Labrador Transmission Assets. These are the transmission assets that link the Muskrat Falls Generation Station to the Churchill Falls Generation Station and its associated transmission system.

- NSPML will own 100 percent of the Maritime Link facilities. These are the transmission assets that link the Newfoundland electrical system to Nova Scotia's electrical system. They include two converter stations, subsea cables, and overland transmission to both the Newfoundland and Nova Scotia electrical systems.

- Nalcor's and Emera's percentage ownership of the Labrador-Island Transmission Link is based on the estimated capital costs of each component at the time the project is Sanctioned, and later adjusted for actual capital costs. At current estimates, Emera will own approximately 35 percent of the Labrador-Island Transmission Link.

2.3 From Term Sheet to Formal Agreements

The development of the various commercial agreements necessary to replace and implement the Term Sheet concluded in July 2012, with the signing of the 13 formal agreements listed in Figure 2-3.

Figure 2-3 Formal Agreements

	Agreement	Abbreviation
1	Maritime Link – Joint Development Agreement	MLJDA
2	Energy and Capacity Agreement	ECA
3	Maritime Link (Nalcor) Transmission Service Agreement	Nalcor TSA
4	Maritime Link (Emera) Transmission Service Agreement	Emera TSA
5	Nova Scotia Transmission Utilization Agreement	NSTUA
6	New Brunswick Transmission Utilization Agreement	NBTUA
7	MEPCO Transmission Rights Agreement	TRA
8	Interconnection Operators Agreement	IOA
9	Joint Operations Agreement	JOA
10	Newfoundland and Labrador Development Agreement	NLDA
11	Labrador-Island Link Limited Partnership Agreement	LILPA
12	Inter-Provincial Agreement	
13	Supplemental Agreement	

Each of these agreements is provided as Appendices 2.02 to 2.14. Appendix 2.01 provides a concise summary of the key elements of the agreements.

Subsequently, on December 17, 2012, Emera and Nalcor signed a Sanction Agreement which amended certain of the agreements referenced above – in particular the Maritime Link Joint Development Agreement. This agreement is also attached as Appendix 2.15 and summarized in Appendix 2.01. At the same time, the parties signed a Project Oversight Agreement, which is attached as Appendix 2.16 and summarized in Appendix 2.01.

As noted in Section 2.1, NSPML and NS Power have signed an Agency and Service Agreement to reflect the relationship between the two companies. NS Power's responsibilities and the nature of the relationship between the two companies are described in Sections 4 and 8. This agreement is attached as Appendix 8.01.

NSPML and Bayside Power L.P. have signed a Backstop Energy Agreement which reflects Nalcor's right pursuant to the New Brunswick Transmission Utilization Agreement and the MEPCO Transmission Rights Agreement to put electricity to NSPML in certain circumstances. This agreement, which is described in Section 8, is attached as Appendix 8.03.

3.0 DESIGN CONCEPT OF THE MARITIME LINK

The Regulations require that this Application include engineering and design details sufficient to enable the UARB to approve the Maritime Link Project in accordance with the applicable criteria.[20]

This section addresses those details, and is supplemented by further technical detail in Appendix 3.01.

The engineering work and design work for the Maritime Link are ongoing at this time, the project details represented in this section are those used in the present project scope and budget, for which final decisions will be made prior to a decision to commence construction. Where applicable, the following sections include the basis for which the design and budget are based upon, but include reference to technology alternatives which are still under consideration in many cases, pending further engineering assessment or evaluation of supplier proposals.

As an example, NSPML included a specific subsea cable technology in the budget and an estimated cost based upon engineering assessments completed to date, which included a detailed subsea survey of the corridor where the cable is expected to be located. When evaluation of proposals from experienced cable suppliers is complete, the project design will be finalized and budgets updated to reflect the potential contract value. At that time, the certainty of Project Costs improves, as well as, schedule and scope of work. Similar progress on design, schedule and cost will be achieved during 2013, with regards to major components such as converters and substations, transmission structures and materials.

The development of major project estimates commonly include an assessment of the range of completion costs, the range converges as the degree of project definition or

[20] Paragraph 5(5)(c) of the Regulations.

engineering certainty improves. The range of costs represented in this application are based upon industry practice for major projects and follow a decision gate process for review and approval.

The Decision Gate (DG) process was developed by industry for application on major projects, with the basic principle that project scope and cost certainty improve with increased front end engineering design (FEED), as the degree of project definition and cost certainty improves, the risks and range of potential completion costs reduces. The DG process being used by NSPML has five gates or approvals, with the project having passed DG1 at the time of the term sheet being signed between Emera and Nalcor in November 2010.

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. NSPML will continue to advance the engineering and design, improve the degree of project definition and attain market based pricing for many components as it moves to DG3 in 2013, prior to construction authorization. The DG4 is aligned with start of commissioning and DG5 is the transfer to operations.

3.1 Objectives of the Transmission Connection

The Maritime Link 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.

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's own needs, but up to 500 MW will be available for export from Newfoundland to Nova Scotia. Of the 500 MW export capacity, Nova Scotia will receive at least 170 MW, less the losses to deliver it to Bottom Brook and then through the Maritime Link to Woodbine, plus a supplemental block of energy that NSPML will receive during the first five years of Project operation. This will allow NS Power to retire one or two coal units. The balance of the 500 MW export would be available for sale to NS Power by Nalcor, or it could pass through Nova Scotia to buyers beyond the NS border.

The main purpose of the Maritime Link Project is to deliver power from Newfoundland to Nova Scotia, and this will be its usual mode of operation. However, in special circumstances, the facility will be able to carry power in the opposite direction, from Nova Scotia to Newfoundland and Labrador, and the design of the facility will accommodate this mode of operation as well.

3.2 System Design Development

Before beginning detailed project design which is not yet complete, NSPML made certain key decisions about the project's conceptual design, its transmission routes, and the location of key facilities. Sections 3.2.1 through 3.2.12 explain these choices.

There are three options for the physical configuration of transmission lines: overhead, underground, and, where applicable, subsea. The choice among these options is driven by routing, electrical design, and cost. Preliminary design calls for overhead transmission in most areas and underground in specific areas based on an integrated assessment of technical, economic, and environmental factors.

For crossing the Cabot Strait, subsea cable is the only option. NSPML is currently finalizing the Basis of Design at DG2 which could include changes to the preliminary design for the mix of overhead and underground.

3.2.1 Alternating Current versus Direct Current

The choice between alternating current (AC) and direct current (DC) is driven by electrical design and cost. AC is the dominant form of transmission around the world, including the provinces of Newfoundland and Labrador and Nova Scotia. It has several advantages, including flexibility for future expansion and interconnection. However, there are two types of applications where DC transmission offers advantages over AC transmission: large-scale power transmission over very long distances, and power transmission over long distances through underground or submarine cables. The principal decision factor for the Maritime Link is the limitation on power transmission through underground and submarine cables. Because of system design limitations, AC is not technically feasible for long, continuous power transmission through underground or submarine cables. A common rule of thumb is that AC transmission is technically feasible only up to 50 km of continuous underground or submarine cable. Since the shortest ocean crossing from Newfoundland to Cape Breton is much longer than 50 km, DC transmission is the only feasible option for this section of the facilities.

NSPML proposes to develop the Maritime Link as a DC connection between the AC electricity systems of Newfoundland and Nova Scotia. Implementation of this project as a DC connection will require equipment to convert AC power to DC, and vice versa, at each end of the DC transmission connection, enabling the new transmission link to connect with the AC electricity systems in both provinces.

3.2.2 AC/DC Converter Technology

Project planners from Nalcor and Emera examined two different AC/DC converter technologies for use on the Maritime Link: Current Source or Line Commutated Conversion (LCC) and Self Commutated or Voltage Source Conversion (VSC). The difference between the two technologies lies in the solid-state devices that form the heart of the AC/DC conversion process. LCC systems are built with high-voltage thyristors, while VSC systems are built with Integrated Gate Bipolar Transistors (IGBT). IGBT-based VSC systems are ideally suited for application to electricity systems with small amounts of connected generation. VSC technology is also well suited for use with HVDC transmission links using underground or submarine cables.

Early studies were undertaken by vendors of AC/DC converter systems to evaluate compatible technologies for the Maritime Link facilities. These studies indicated that VSC technology would be viable for implementation on the project, and would offer many advantages over LCC technology due to the system characteristics in Newfoundland and Nova Scotia. A particular advantage of VSC technology is its adaptability to systems with weak reactive power support, whereas LCC technology requires strong dynamic reactive power support to function effectively. Reactive power support is traditionally provided by strong generation sources connected to the AC system close to the point of interconnection, and is needed to maintain the stable AC system voltages that are important for successful application of LCC technology. If LCC technology were used on the Maritime Link, system studies have indicated that additional dynamic reactive support would be required in Newfoundland and Cape Breton.

An economic comparison of both technologies, which included HVDC line costs, switchyard costs, 230 kV AC line costs/upgrades, converter station costs, and system integration costs, showed that the VSC technology was the economic choice. Since both technologies are viewed as highly reliable, with no identifiable reliability advantages to either technology, and since there is no environmental preference for either technology, the economic comparison is the dominant decision factor.

NSPML has selected Voltage Source Converters as the preferred technology for the two Maritime Link converter stations.

3.2.3 Selection of Underground/Submarine Cable Technology

For the subsea cable, two technologies have dominated the HVDC submarine cable market in recent years. Mass Impregnated Paper (MI) insulated cables have dominated the market for high-voltage and high-power HVDC transmission for many years. However, extruded plastic insulation cables (most commonly Cross-Linked Polyethylene or XLPE) have made steady inroads at progressively higher voltage and power levels. While XLPE cables have traditionally offered lower initial costs, these cables have not yet accumulated the same long and successful operating history at higher voltage levels that is offered by MI cables. To date, the highest power and voltage level for an XLPE insulated submarine HVDC cable is 500 MW and 200 kV, which was the East West Interconnector between Ireland and Wales, completed in 2012.

NSPML has called for proposals to design, supply and install the subsea cable system, and proponents have the option to supply proposals for either MI or XLPE insulated cables. Proponents for the cable supply contract are required to offer documentary evidence of the technical viability and successful project history of the cable technology they offer, and the long-term viability of the proposed cable technologies will be an important part of the evaluation process. Pending a final decision on the cable technology to be used, project cost estimates are based on the assumption that MI cables will be used for the project.

3.2.4 System Interconnection Locations

Decisions about where to locate the AC system interconnections at each end of the DC link, and where to carry out AC to DC conversions, have been important elements of the project design. Interconnection must take place at a point where the existing transmission system is strong enough to accommodate delivery of 500 MW of power. In Newfoundland, project planners considered Bottom Brook Substation and Bay D'Espoir Generating Station as sites for the AC interconnection in Newfoundland. Bottom Brook was selected because it is electrically strong enough to deliver 500 MW into the DC transmission link, which avoids the need for the longer and, therefore, more costly transmission route to Bay d'Espoir. To ensure reliability of supply, the AC connections to Bottom Brook Substation will need strengthening. Section 3.2.12 describes these requirements. NSPML has included Bottom Brook substation as the preferred interconnection location.

In Nova Scotia, project planners have chosen the 345-kV Woodbine Substation as the interconnection site at the receiving end, because Woodbine is a major hub for power generation in Cape Breton, and can handle 500 MW of incoming power for delivery to load centers throughout Nova Scotia. The station must be expanded to accommodate the interconnection of the AC/DC converters, and to provide increased capacity to transfer power from the 345-kV system to the 230-kV system of NS Power.

3.2.5 AC/DC Converter Locations

The Maritime Link facilities will interconnect with the existing AC systems at Bottom Brook Substation in Newfoundland and Woodbine Substation in Nova Scotia. The transmission path for the Maritime Link will therefore include an overland route from Bottom Brook Substation to the seashore, the ocean crossing from Newfoundland to Cape Breton, and an overland route from the Cape Breton seashore to Woodbine Substation. Given these AC interconnection locations, it would be possible to build the stations that convert AC power to DC power anywhere between Bottom Brook Substation and the seashore, and anywhere between the Cape Breton seashore and the Woodbine Substation. However, because DC transmission costs less to build per km, and exhibits lower electrical losses than an AC transmission line of equivalent capacity, it is economically desirable to minimize the length of AC transmission construction and maximize the length of DC transmission construction. In addition, sites close to Woodbine and Bottom Brook offer operational advantages related to site accessibility for maintenance, and also for avoidance of siting critical converter installations within the coastal salt spray areas.

For economic and operational reasons, project planners have decided to build the AC/DC converter stations immediately adjacent to the Bottom Brook and Woodbine Substations.

3.2.6 HVDC Voltage Level

For the required 500 MW power transfer level, project planners considered HVDC voltage levels of +/- 200 kV and +/- 250 kV. Higher voltage on the DC portion of the project will reduce power losses but will increase the initial capital cost, these factors are considered in the optimization and selection of voltage levels.

The system will have two separate cables, consisting of a positive and negative pole that together deliver 500 MW. Each pole can operate independently, transmitting up to 250 MW using a common neutral return path.

- For the +/- 200 kV system, a 1,250 Ampere (A) current will flow in each pole during maximum power delivery.

- For the +/- 250 kV system, a 1,000 Ampere current will flow in each pole during maximum power delivery.

The portion of the system with DC overhead transmission lines can easily accommodate these voltage and current levels. Optimization of line voltage and resulting losses are necessary to minimize long-term cost. Both of the cable types under consideration for the subsea crossing can handle the 200 kV level, but only the MI cable insulation is proven at the 250 kV level. Likewise, in the AC/DC conversion process, VSC technology is proven at the 350 kV level, NSPML has developed the DC portion of the project at the +/- 200 kV voltage level considering these factors and based upon VSC converters and MI cable.

3.2.7 Neutral Return Path

The HVDC portion of the Maritime Link will have two separate cables, a negative pole and a positive pole, together capable of carrying 500 MW. Asymmetrical bipolar and dual-monopolar DC transmission systems require a solid return path in addition to the pole conductors. During bipolar operation, unbalanced currents between the poles (approximately 12.5 A or 1 percent of full load current) will flow through the return path. During monopolar operation, full load current of 1,250 A may flow through the return path, it must maintain that power level even during planned or unplanned outages on either of the poles. In the event of such an interruption, the return path will be a primary path for the reduced power transmission. The return path must achieve very low resistance to ensure stable and reliable performance of the AC/DC converters.

There are two principal ways of providing a return path rated for full system current: metallic return and earth return. Figures 3-1 and 3-2 show these options.

Figure 3-1 Metallic Return

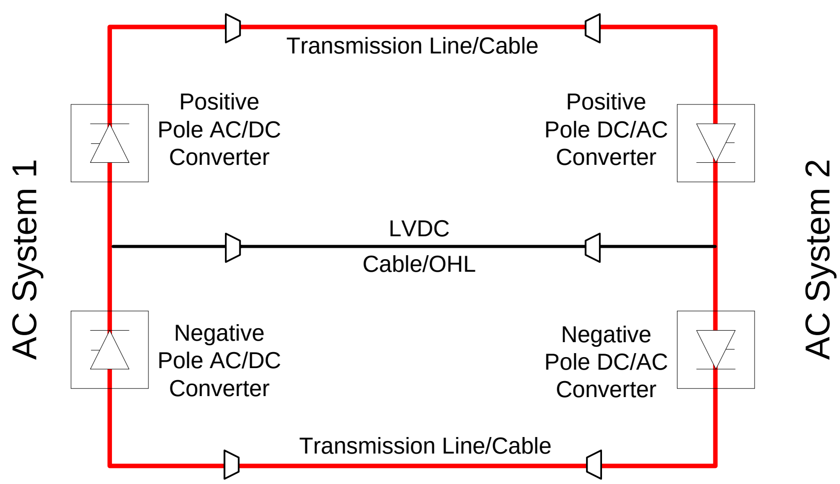
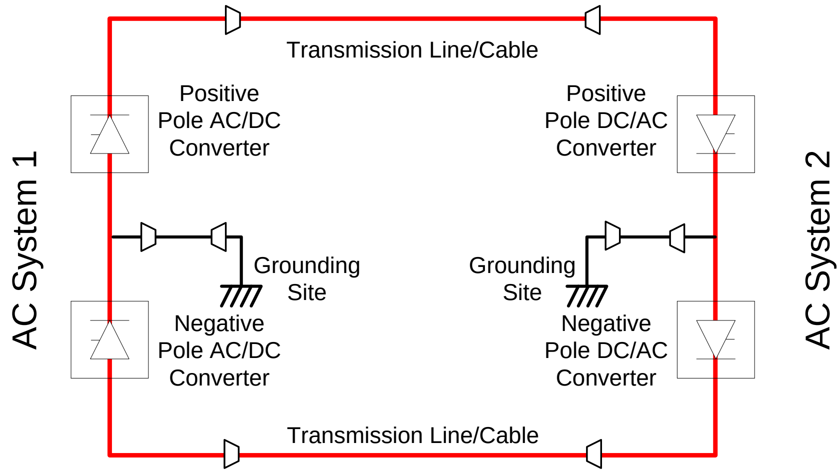


Figure 3-2 Earth Return



Metallic return requires installation of a fully rated metallic conductor from end to end along the transmission path. Ground return requires a low resistance connection to earth that will permit the return current to flow in a virtually infinite number of paths through the earth from the receiving end to the sending end of the HVDC link.

Metallic return requires much higher capital costs than earth return, due to the need for a third conductor along the transmission path, including the subsea section. Metallic return also typically has at least ten times higher resistance than ground return, leading to much higher operating losses. HVDC projects requiring fully rated monopolar operation are consistently built with ground rather than metallic return.

Since technically feasible options exist for implementation of an earth return system, which are acceptable from an environmental standpoint and maintain adequate separation from metallic infrastructure, NSPML has decided to use an earth return on the Maritime Link.

The earth's effectiveness as a return path depends on achieving a very low resistance connection to ground. This is the role of the grounding sites shown in Figure 3-2. There are two main types of grounding sites used for HVDC transmission projects: those in contact with earth, and those in contact with sea water. Grounding sites in contact with sea water can be further subdivided into three types: sites developed in the sea; sites developed in a man-made shoreline pond or natural lagoon; and sites developed at a beach in well casings immersed in saturated soil at a distance inland from the shoreline.

The geology of Newfoundland and the northern part of Nova Scotia is such that grounding sites in contact with earth are not a viable option. With high electrical resistivity and low thermal conductivity, it would be difficult if not impossible to achieve a low-resistance ground connection.

A sea grounding site is not considered viable due to construction challenges in the marine environment, possible impacts of construction and operation on the marine environment, and accessibility issues for maintenance. A beach grounding site is not considered viable, due to design and performance issues arising from the prevalence of rock formations at beach locations in the area, and the lack of substantial soil cover above these rock formations.

Shore grounding sites, on the other hand, offer the advantages of low electrical resistance to ground found in salt-water grounding sites, and ease of access for future maintenance. Therefore, a shore grounding site, isolated from the sea by a breakwater, is the preferred option for the Maritime Link HVDC scheme. These shore-based grounding sites at each end of the submarine cable will be located within 50 km of their respective converter stations. Dedicated grounding lines will connect the converter stations to the grounding sites.

As a rule, the grounding sites will carry very little current, based only on minor unbalance between the positive and negative poles. Only a sustained outage of a pole conductor will require sustained use of the earth return path. As rare as these events may be, the ground sites must be designed to carry full rated system current for an extended period of time without incident.

3.2.8 Location of Shoreline Grounding Sites

Site selection for shoreline grounding sites is driven by electrical and oceanographic design requirements, constructability requirements, and environmental and land acquisition and access requirements. The sites must be able to achieve very low ground resistance and good thermal heat dissipation under all tidal conditions. The near-shore bathymetry of the sites must be suitable for construction of a breakwater to enclose a shoreline pond, and the wave activity in the area must be conducive to long-term stability of the breakwater. The sites must be available for purchase, and accessible by road for maintenance.

Project planners selected preliminary locations for the grounding sites based on criteria that included proximity to the converter station, proximity to existing transmission or road rights of way, extent of natural shore protection, and proximity to buried metallic infrastructure. Field observations at short-listed sites validated the selection criteria and documented local seawater salinity. At the same time, research and stakeholder consultation on key environmental and socio-economic criteria added to the available body of knowledge and understanding of such local concerns as land availability, land protection, Mi'kmaq interests (in Nova Scotia), commercial fishery interests, and potential for interaction with species of conservation interest.

Analysis of site-specific criteria such as ground resistivity, near shore bathymetry, and shoreline topography confirmed that the following sites are technically feasible.

Figure 3-3 Technically Feasible Sites

Newfoundland	Cape Breton
• St. George's • Port Harmon entrance to channel • St. George's River estuary • Indian Head	• NW Arm Sydney Harbour • Gabarus Bay • Mira Bay • Big Lorraine • Little Lorraine

Project planners evaluated all of these sites based on technical, environmental, land tenure, access, constructability, maintainability, and cost factors. These evaluations led to the identification of the St. George's site in Newfoundland and the Big Lorraine site in Nova Scotia as preferred sites, although all of the options presented above have been presented as options in the environmental review process.

3.2.9 Cable Routing and Locations of Subsea Cable Landing Sites

Minimizing the length of the subsea cable became a principal driver in the selection of the cable route and the shore landing sites. Planners, from a technical perspective, also considered coastal topography at the landing sites, near-shore geology, and the impact of the landing sites on the submarine cable route and the overland transmission routes. There are many aspects of the final cable design which are still under consideration including the routing, however the scope and budget are based upon the route described in this section.

Sites near the Southwestern tip of Newfoundland offer the shortest possible cable route to Cape Breton. In Cape Breton, landing sites on the Cape Breton Highlands peninsula were considered, in an attempt to minimize the subsea cable length, but these options were quickly discarded due to the added cost and implementation challenges for the overhead

HVDC construction in this area. After ruling out the Highlands area, only sites in the North Shore areas to the east and west of Sydney Harbor were considered.

Based on this preliminary definition of prospective cable landing sites, a preliminary cable route was selected for study, and extensive bathymetric surveys were undertaken of the sea bottom between these prospective landing areas. These surveys helped in identification of corridors suitable for installation of the subsea cables, and in refining the selection of the cable landing sites.

In Newfoundland, planners focused on the area near the Southwestern tip of the island and identified a site near Cape Ray, based on nearshore geological conditions, stakeholder and environmental constraints, and ease of access.

Within the North shore areas considered in Cape Breton, planners evaluated three alternative sites, at Wreck Cove, Lingan and Point Aconi. Point Aconi was chosen based on reduced cable length, more suitable coastal topography, and nearshore geology.

3.2.10 Method for Onshore and Nearshore Cable Installation

The installation methods for the subsea cables are an important factor in the reliability of a cable system, because the cables can be exposed to damage from a variety of causes. In deep waters (at least 15 meters), a combination of cable spacing on the ocean floor, hydro-jet installation techniques to plow the cables into the sea floor, and stone berms or concrete mattresses to protect cables over ocean-bottom rock outcroppings can adequately address the risks. However, in the nearshore approaches to the cable landings, the number and severity of the risk factors increases, and designers must consider different installation methods.

Shallow waters expose cables to damage from a variety of sources including vessels and anchors, pack ice scouring, and commercial fishing operations. The usual method of guarding against these external influences is to bury the cables deep enough below the ocean floor to avoid or minimize the risk. This is achieved by one of three burial techniques: trenching, horizontal directional drilling and micro-tunneling. NSPML considered all three of these techniques to be technically feasible. Trenching increases schedule risks in the event of inclement weather, and may cause incremental environmental impact on sensitive coastal habitats. Micro-tunneling carries additional execution risk. While consideration is given to the final selection of nearshore and onshore installation, NSPML has included the use of horizontal directional drilling at this time, because it avoids disturbance of sensitive coastal habitats, minimizes project execution risk, and offers cost savings compared to micro-tunneling.

3.2.11 System Reinforcement Requirements

System studies undertaken by Nalcor and NSPML have demonstrated that the transmission system in the vicinity of Bottom Brook Substation has sufficient strength to supply 500 MW of power to the AC/DC converters when all Newfoundland transmission facilities are in service. However, Bottom Brook Substation connects to the Newfoundland transmission grid by just two transmission circuits: TL211 from Massey Drive, and TL233 from Buchans. A third 230-kV line into Bottom Brook Substation, independent of the supply path to Massey Drive and Buchans, would provide added security for the 500 MW delivery into the Bottom Brook Substation.

Planning studies have demonstrated that the addition of the 230-kV transmission link from Granite Canal to Bottom Brook, along with the two existing transmission lines, would ensure reliable delivery of 500 MW of power to Bottom Brook with minimal additional upgrades to the system and using VSC technology. While system study work continues, NSPML has included the cost of the minor system improvements, the 230-kv AC line from Granite Canal to Bottom Brook and reliable industry standard substation arrangements in the project scope and budget.

The Nova Scotia end of the connection requires upgrades to accommodate the 500 MW delivery, including a minimum of 170 MW to be consumed in the province of Nova

Scotia, and up to 330 MW to be wheeled through Nova Scotia (note that these figures represent the gross energy at Muskrat Falls, reduced by line losses for transmission to the Bottom Brook and Woodbine converter stations). To reliably accommodate the delivery of 500 MW (less transmission losses) and the prospective wheeling requirements, the Woodbine Substation will need a second 345/230-kV transformer, and an extension of the 230-kV bus to facilitate two additional 230-kV transmission lines.

To facilitate the prospective power wheeling requirements, NS Power has identified the need for upgrades to existing 230-kV transmission lines and substations. Section 8 of this Application provides more detail on these requirements.

3.2.12 Routing of Transmission Lines

a) Overhead HVDC Transmission Routing

The **+/-** 200 kV DC overhead line between Bottom Brook and Cape Ray is proposed to run almost entirely alongside existing AC transmission facilities South of Bottom Brook, including 138-kV and 69-kV transmission lines owned by Newfoundland and Labrador Hydro. NSPML plans to expand the rights of way for these existing transmission lines to accommodate the new HVDC line, except for areas of land or environmental constraints where the new line may deviate from the existing line to avoid the constraints. The estimated route length of this corridor is 142 km.

The **+/-** 200 kV DC overhead line between Point Aconi and Woodbine is also proposed to run almost entirely alongside existing AC transmission lines, in this case a single 230-kV transmission line (L7015) owned by NS Power. Over most of the route length, NSPML plans to expand the right of way of the existing transmission line to accommodate the new HVDC transmission line. Along certain sections of the route, the existing line L7015 runs close to other transmission infrastructure. NSPML plans to reconfigure the existing transmission lines through these areas to provide enough space for the new HVDC line. The estimated route length of the HVDC line in Nova Scotia is 46 km.

In the final approach to the Woodbine Converter Station, the new HVDC transmission line will cross over several existing transmission circuits. This aerial crossing of multiple circuits will require an appropriate solution to address reliability concerns, and an underground cable solution has been adopted.

b) Submarine Cable Routing

Four factors have guided route selection for the subsea cable:

- the need to minimize the route length and resulting cost
- the need to avoid major obstructions and jagged rock outcroppings
- the need to avoid existing subsea infrastructure
- the need to avoid environmentally sensitive areas

NSPML acquired detailed imagery of the sea floor, along with soil sampling, and sediment collection and analysis. In areas where remotely operated vehicles identified such features as visual depressions or obstructions, more detailed surveys were carried out. Near the shore, planners used Light Detection And Ranging (LIDAR) for shallow water assessment of the seafloor terrain. Planning also included studies of sea currents, silt migration, and ice patterns.

The proposed route follows a nearly straight line between Cape Ray and Point Aconi. NSPML has defined the route as a 2000-meter-wide study corridor, to facilitate the Environmental Assessment process and to provide flexibility for NSPML and the cable supplier to adopt a final route and cable spacing strategy that minimizes the risk of cable damage, maximizes cable system reliability, and avoids sensitive and commercially important fisheries. The estimated subsea route length is 170 km.

c) 230 kV AC Transmission Routing

NSPML considered two possible routes for the proposed new 230-kV AC transmission line between Granite Canal and Bottom Brook: one traveling north of Granite Lake, and a second traveling south of Granite Lake. Both were deemed technically feasible. The southern route is longer, and would otherwise be more expensive to build if not for the use of existing rights of way. It also will cause less habitat disturbance and fragmentation. To minimize the Project's environmental impact, NSPML has included the southern route, with a length of 160 km, for further development including environmental study.

3.2.13 Adopted System Design Concept

The Maritime Link facilities include eight main components:

- In Newfoundland, a new overhead AC transmission line between Granite Canal and Bottom Brook, along with limited system upgrades such as the reconfiguration of line terminations at the Bay d'Espoir Substation.
- In Newfoundland, new substations adjacent to the existing Granite Canal Generating Station and Bottom Brook Substation, to accommodate the new 230-kV AC transmission line, and to provide two switched connections for the two converter transformers at Bottom Brook Converter Station.
- AC/DC converter stations at a new site adjacent to Bottom Brook Substation in Newfoundland, and at a new site adjacent to Woodbine Substation in Cape Breton.
- New shoreline grounding sites, with currently preferred sites at St. George's in Newfoundland and Big Lorraine in Cape Breton, and grounding lines to connect

those sites with their respective converter stations at Bottom Brook in Newfoundland and Woodbine in Cape Breton.

- In Newfoundland, a new overhead DC transmission line between Bottom Brook and Cape Ray, and in Cape Breton, a new overhead DC transmission line between Point Aconi and Woodbine Substation.
- At Cape Ray in Newfoundland and Point Aconi in Cape Breton, overhead-to-underground transition compounds to connect the overhead DC transmission lines to the underground cables.
- Two DC cables across the Cabot Strait, including: underground cables from the overhead-to-underground transition compounds to the cable landing sites at the shoreline near Cape Ray, Newfoundland, and Point Aconi, Cape Breton; underground-to-submarine transitions at the same landing sites; and submarine cables connecting the Cape Ray and Point Aconi cable landing sites.
- In Nova Scotia, expansion of the Woodbine Substation to accommodate two switched connections for the converter transformers in the Woodbine Converter Station, an additional 345/230-kV transformer with bus extensions for two additional 230-kV lines, plus upgrades and modifications to other 230-kV and 345-kV transmission lines and substations in Nova Scotia.

Figure 3-4 shows the entire Maritime Link, with overland sections of the HVDC line in dark red, submarine sections of the HVDC line in grey, overland sections of the HVAC line in light red, and grounding lines in blue. The map also shows the transition compounds and converter sites.

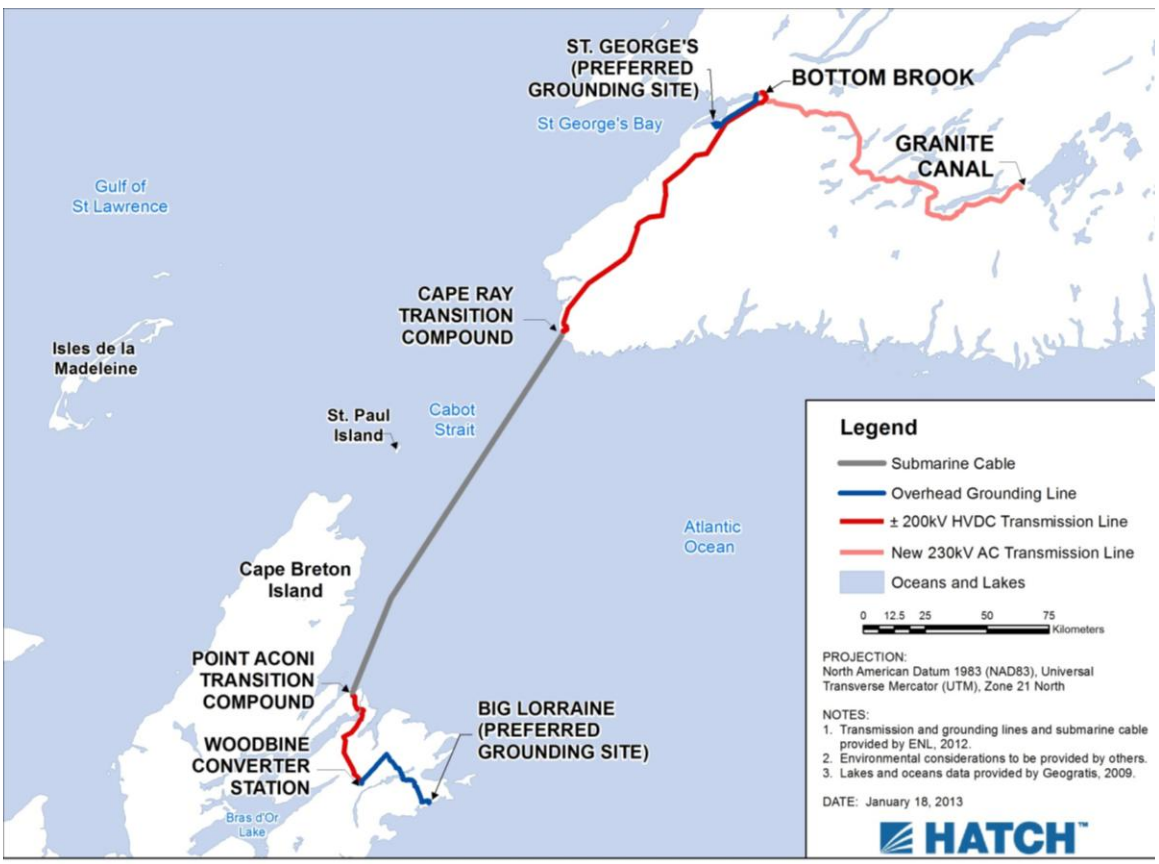
3.3 Technical Overview

The Maritime Link will consist of two broad groups of facilities: those needed for the DC transmission link, and those needed to connect this link to the AC transmission systems of Newfoundland and Nova Scotia. Sections 3.4.1 through 3.4.6 describe these facilities.

3.3.1 HVDC Line

The DC transmission line will run from Bottom Brook Substation in Newfoundland to Woodbine Substation in Cape Breton. As discussed in Section 3.2.7, project planners have chosen +/- 200 kilovolts (kV) as the voltage for this system. The line will have two conductors or poles, plus an overhead shield wire.

Figure 3-4 Maritime Link Project



The route from Bottom Brook to Woodbine consists of three sections: a 142 km overhead section from Bottom Brook to the shore near Cape Ray, a 170 km subsea section across the Cabot Strait, and a 47 km section from the shore near Point Aconi to the Woodbine substation. As part of the 47-km route in Cape Breton, there will be an overhead-to-underground transition connected to about 500 meters of underground DC cable just outside the Woodbine station. This is needed for the line to cross several existing transmission lines, avoiding risks of faults affecting multiple AC and DC circuits.

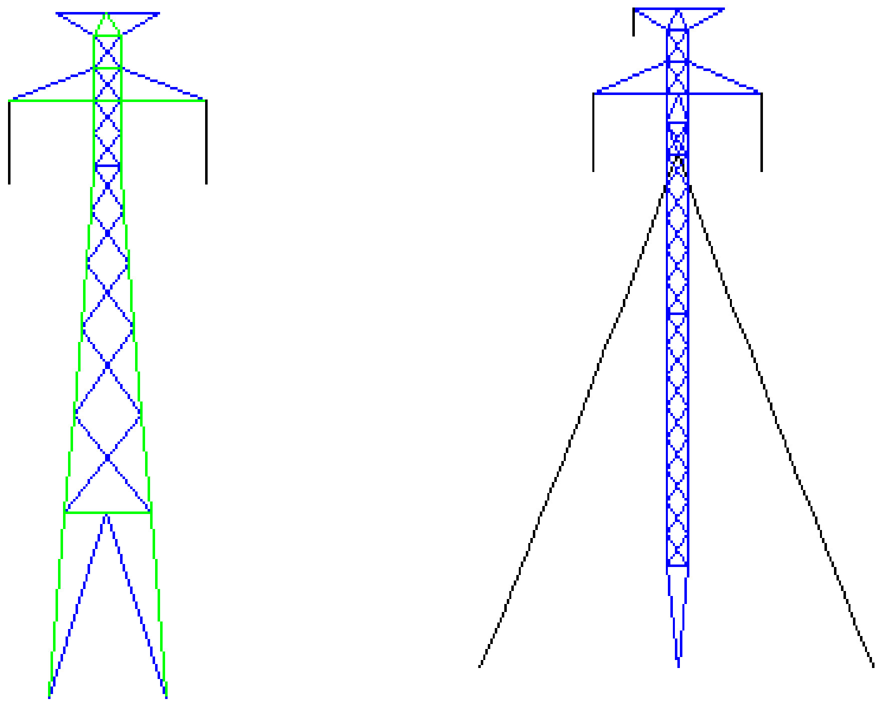
At transition compounds about one km inland from the shore, the overhead transmission conductors will be connected to insulated underground cables, which will be run to the seashore cable landing sites. Land-sea transition sites at the seashore will connect the underground cables to the submarine cables, and anchor the submarine cables to land. The overhead HVDC lines in Newfoundland and Nova Scotia will consist of steel structures supporting two sets of pole conductors. Two additional wires will shield the pole conductors against lightning strikes, and carry fiber optic communication channels. The pole conductors will be 45 mm diameter Aluminum Conductor Steel Reinforced (ACSR), while the optical ground wire (OPGW) shield wires will be alumoweld steel wires with a fiber optic core.

In Newfoundland, the project design team chose guyed lattice-steel towers as the preferred support structures, because their light weight offers low cost and flexibility for various methods of erection. The structures will be 30-40 m high, depending on terrain. These structures are depicted graphically in Figure 3.5 (a).

Due to limitations on the width of available rights of way, the design team decided to use heavier, self-supporting steel structures, 30-35 m high, for the Cape Breton section of the HVDC line. The average span between support structures will be 300-400 meters, with flexibility to adjust individual span lengths to accommodate road, rail and stream crossings, avoid environmentally sensitive areas, and manage other terrain considerations. These structures are depicted graphically in Figure 3.5 (b).

The required right-of-way width for the overland lines is 50 meters for the guyed steel structures, and 45 meters for the self-supporting steel structures. In both cases, the rights of way must be cleared of vegetation. Over almost the entire route length, the lines run alongside existing transmission lines, for which the rights of way will be widened appropriately, based upon availability of adjacent land

Figure 3-5 Typical Structures for the HVDC Overhead Lines



(a) Newfoundland Structures (b) Cape Breton Structures

Routing the HVDC transmission line almost entirely alongside existing transmission lines means access roads are generally available. Construction crews will improve these roads as needed to provide access to the corridor for construction of tower foundations, tower erection, and future maintenance of the transmission line. In areas where access is very difficult, the project will consider aerial (helicopter) construction techniques.

The proposed routes for the overland transmission lines in Newfoundland and Cape Breton are shown as dark red lines in Figure 3-4. Preliminary design has been completed for these lines; structure locations and heights have been selected based on surveys of the topography in the corridors. Planners have drawn up bills of material, which the Project used as the basis for cost estimates.

The overhead-to-underground transition compounds will be fenced sites of about 500 square meters, located about one km inland from the cable landing sites near Cape Ray, Newfoundland, and Point Aconi, Nova Scotia. Each compound will contain a 13 x 20 meter building, 12 meters high, to house roof-mounted insulated connections for the aerial transmission conductors, and internal connections to the underground transmission cables. Each building will include staff work areas, control panels, and communication equipment.

The overhead cables will enter the roof of the building, where they will connect to a pair of underground transmission cables. These, in turn, will run through the floor of the building and out of the transition compound to the land-sea cable anchor sites where the submarine cables make landfall.

Preliminary electrical, civil, and structural design has been completed for the overhead-to-underground transition compounds. Bills of material based on these designs have been used to develop cost estimates.

The two submarine cables will run from the Newfoundland land-sea cable anchor site near Cape Ray to the Nova Scotia land-sea cable anchor site near Point Aconi. In Figure 3-4, the grey line represents the planned route of the submarine cable. Specially equipped cable-laying ships will install the cables, under a turnkey design-build contract.

An important aspect of submarine cable systems is their exposure to damage from marine vessels, ship anchors, and pack ice, with long delays for repair or replacement of damaged cables. The design-build contractor must adequately protect the cables against such damage, to ensure attainment of the desired reliability standard. Protective measures may include hydraulic or mechanical trenching of the cables into the sea bottom, various ways of providing physical protection to the installed cables, and physical separation of the cables on the sea bottom to prevent damage to both cables from a single incident. The cable supply contractor will be broadly responsible for decisions about cable installation techniques in deep water. The contractor has been given a 2000-meter wide corridor in which to install the cables in a manner that meets the reliability criterion. In shallow waters such as the near-shore approaches to the cable landings, where the exposure is greatest, the cables will be installed using horizontal directional drilling techniques until the water depth reaches a level (at least 12 meters) that affords some protection**.** The design-build contractor will be responsible for designing and implementing cable protection measures over the entire length of the cable's subsea route, sufficient to achieve a targeted return period of up to 1,000 years between failures of the cable system.

The design-build contractor will design, supply, and install the two submarine cables, which will consist of either MI or XLPE insulated cables. The core conductor of the cables will be either copper or aluminum. The cable will consist of a core conductor surrounded by electrical insulation, embedded fiber optic communication cable over all or part of the cable length, and overall steel armor for cable protection. The design-build contractor will size the core conductor to achieve the targeted power transfer capacity.

3.3.2 AC/DC Converters

The AC/DC converters convert AC power to DC power at the sending end and DC power to AC power at the receiving end. These are complex networks of power transformers, high-voltage, solid-state rectifiers and inverters, filters, and smoothing reactors. The converters make the sending terminal behave like a high-voltage battery, and make the receiving terminal behave like a high-voltage load connection. They are configured to deliver a controllable and stable amount of DC power into the HVDC transmission link, from the sending-end converter to the receiving-end converter.

The AC/DC converters for the Maritime Link will operate as a **+/-** 200-kV dual monopole. One pole will operate at **+** 200 kV compared to ground; the other will operate at - 200 kV compared to ground. The positive and negative poles of the AC/DC converters are designed as independent installations, each capable of supplying 250 MW of power at **+** 200 kV on the positive pole or -200 kV on the negative pole. When operated independently, current will flow through the pole conductor and return through the earth and the grounding lines. When operated normally, with both poles in service, current will flow out one pole conductor and return through the other, with some small differential current being transmitted through the earth/sea-water and the ground lines. In the event one pole is out of service, the system will switch automatically to monopole operation using the remaining healthy pole and the ground return path.

The AC/DC converter sites will be located next to the new 230-kV Bottom Brook Switchyard and the existing 345-kV Woodbine Substation. Fenced compounds at these sites will enclose an area of about 135 x 240 meters, including outdoor transformers and other electrical equipment. A 90 x 45 meter building, about 13 meters high, will house the main valve hall for rectifiers and inverters, as well as, control panels, communication equipment, a maintenance shop, and an office.

The AC/DC converter stations will be designed, manufactured, shipped, constructed and commissioned under terms of a turnkey design-build contract, including site development and servicing. Technical specifications for this bid process, including performance specifications for the VSC system, are now under development.

3.3.3 Grounding Line and Grounding Site

As discussed in Section 3.2.8, the HVDC transmission link requires a low-resistance return path to carry any current unbalance between the positive pole and the negative pole back from the receiving end of the system (normally Nova Scotia) to the sending end of the system (normally Newfoundland). This return path must be capable of carrying full rated system current for extended periods during failures or maintenance outages on either the positive or negative pole of the system. To achieve this low-resistance connection, NSPML has chosen a shoreline grounding site connected to the converter stations at Bottom Brook and Woodbine by dedicated grounding lines. As discussed in Section 3.2.9, the shoreline grounding sites will be located in Southwestern Newfoundland and Northeastern Cape Breton, with currently preferred sites at St. George's, Newfoundland, and Big Lorraine, Cape Breton.

A shore grounding site consists of a man-made saltwater pond at the seashore, created by building a breakwater to enclose the pond. The breakwater must be strong enough to withstand wave action from the sea, but it must also be water-permeable to allow free movement of salt-water from the ocean in and out of the pond.

Inside the breakwater, the connection to ground is achieved by installing many grounding elements in the salt water, near the bottom of the breakwater wall. Each grounding element will be connected to a junction box at the top of the breakwater wall, and these will be connected at a common junction inside the fenced site, on the land-side of the shore grounding site.

Work is underway to design the grounding sites, including the breakwater design, material selection for the grounding elements, and determining the number of grounding elements needed to achieve the target ground resistance. Studies are also evaluating the electrical and magnetic performance of the electrode sites, and assessing environmental and infrastructure impacts, to support environmental planning.

The grounding lines themselves will consist of distribution-class power lines from the AC/DC converter sites at Bottom Brook and Woodbine to their respective shore grounding sites near St George's and Big Lorraine. These lines will operate at a low voltage and high current. At the shore grounding sites, voltage will be effectively zero compared to ground, rising to a maximum of a few thousand volts at the converter sites, due to the voltage drop over the conductors of the grounding lines. The ground lines will run on wooden poles, similar to those used by Newfoundland and Labrador Hydro and Nova Scotia Power for 5-kV class distribution lines. The grounding lines will be built with two sub-conductors, using 28.6 mm diameter aluminum stranded conductor. The route from Bottom Brook to the currently preferred St. George's site is 28 km long, while that from Woodbine to the currently preferred Big Lorraine site is 47 km. In both cases, the grounding lines will run along existing road and power line rights of way throughout their length.

Preliminary design has been completed for the grounding lines in Newfoundland and Cape Breton, including selection of structure locations and heights based on estimated corridor topography. The NSPML design team has prepared bills of material that have been used in the development of cost estimates.

3.3.4 Transmission Reinforcement

As described in Section 3.2.12, NSPML will develop a new 230-kV transmission line from Granite Canal to Bottom Brook. This transmission facility is needed to ensure that 500 MW of transmission capacity can be delivered into Bottom Brook Substation.
As discussed in Section 3.2.13, the 230-kV line will follow a path south of Granite Lake, shown as a light red line in Figure 3-4. The 160 km line will run mainly through undeveloped Crown land with limited access. The line will use wooden poles in an H-Frame configuration, which will meet the NL Hydro construction standard for 230-kV wood pole lines. To handle the maximum expected power transfer, project planners have assessed a 28 mm diameter ACSR conductor for design and estimating purposes at this time.

The line will require a 40-meter cleared right-of-way. Where the line runs parallel to existing roads, these roads will be upgraded as needed for construction and maintenance. Where the line strays from existing roads, the project will use helicopter construction instead of building new roads.

Preliminary design of this new transmission line is complete, including selection of structure locations and heights based on topographic surveys of the corridor. Bills of material based on these designs have been used to prepare cost estimates.

3.3.5 Substation Expansion Facilities

Connecting the HVDC link into the NL Hydro and NS Power transmission systems will require expansion of the Bottom Brook and Woodbine Substations. At a minimum, integration will require the addition of two switched connections into each substation to serve as interconnection points for the two converter transformers installed inside each AC/DC converter compound. A new switchyard has been proposed adjacent to the existing Bottom Brook Substation, to achieve the required functionality and reliability. The new switchyard will provide reliable interconnection between the existing 230-kV lines and transformers and the two new connections for the converter transformers. An industry standard switchyard configuration has been selected for the Bottom Brook switchyard to achieve the desired level of station reliability.

Woodbine Substation in Nova Scotia is a 345-kV switchyard, built with provision for future expansion. The expanded switchyard will include two additional 345-kV connections for the converter transformers in the adjacent AC/DC converter compound, and a second 345/230-kV transformer with 230-kV bus extension to accommodate two new 230-kV line terminations.

The planned 230-kV transmission link between Granite Canal and Bottom Brook will require additional substation facilities at both locations. The project design team has designed the new switchyard at Bottom Brook to accommodate an additional connection for the 230-kV line to Granite Canal.

The existing 230-kV substation at Granite Canal consists of a single 230-kV connection for the nearby Granite Canal hydro station, and a 230-kV line to Upper Salmon. The project will require a new Granite Canal switchyard to provide reliable and selective switching for these facilities and for the new transmission line to Bottom Brook. There are also upgrades included for the Bay d'Espoir and Upper Salmon Substations.

NSPML has completed preliminary electrical, civil, and structural design for the new switchyards at Bottom Brook and Granite Canal, and NS Power has completed preliminary design development for the expansion of Woodbine Substation. Bills of materials based on these designs have served as the basis for project cost estimates.

3.3.6 Modification of Existing Lines

Some portions of the existing transmission lines along the route of the new HVDC line in Nova Scotia will require localized relocations to provide sufficient right-of-way for the new line. Project planners have developed preliminary designs for these relocations, and drawn up bills of material to support the cost estimates.

3.4 Technical Feasibility

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 only areas where planners have incorporated technologies which are new to Nova Scotia are the AC/DC converter stations and the HVDC subsea cable links. However, Nova Scotia is not the first to utilize these technologies as they are quite common in applications around the world, in various configurations with higher transfer capabilities, longer and deeper subsea cables and higher operating voltages. This section of the Application provides further detail about the technical aspects of these components, to demonstrate that the proposed technologies have been deployed successfully on projects similar to the Maritime Link, and are well proven in similar applications.

As described in Section 3.2.3 above, the AC/DC converter stations will use a system known as “Voltage Source (Self-Commutated) Converter” (VSC) technology. This is distinguished from “Line Commutated (Current Source) Converter” (LCC) technology which has dominated HVDC transmission projects for most of the last 40+ years. The two technologies differ in the nature and composition of the high-voltage solid-state devices that constitute the heart of the AC/DC conversion process. These characteristics also lead to differences in the cost and electrical performance of the facilities.

VSC systems use Insulated Gate Bipolar Transistor (IGBT) valves for their critical rectification and inversion activities, whereas LCC systems use thyristors for this purpose. The electrical characteristics of IGBT-based converters lend themselves to installations with low fault current (low system strength) and weak reactive support at the sending and receiving ends of the DC links, and to DC transmission links that include underground or submarine cables. For this reason, VSC converters were initially low-cost applications at lower voltages due to the system benefits of VSC, in the range of 50 kV to 150 kV, particularly those supplying underground or submarine DC cable links. Examples include supply to isolated island systems or off-shore platforms more than 50 km offshore.

As VSC technology proved itself at lower voltages, its use expanded to installations with progressively higher voltages. In recent years, VSC technology has found widespread use at voltages of 150 kV and 200 kV and is now in-service at 350 kV on the Caprivi Link. Some applications of VSC technology to HVDC projects are shown in Figure 3-6 below.

Figure 3-6 Applications of VSC Technology

Projects using VSC technology	
1997	First VSC trial installation in Sweden (+/- 10 kV, 3 MW)
1999	Hagfors, Sweden, ABB (+/- 10 kV, 22 MW) Gotland, Sweden, ABB (+/- 60 kV, 40 MW, 70 km polymer cables)
2000	Tjaereborg, Denmark (+/- 10 kV, 7 MW) Eagle Pass, USA (+/- 18 kV, 36 MW, back to back) DirectLink (Terranora) Project, Australia, ABB (+/- 80 kV, 180 MW, 59 km polymer land cables)
2002	MurrayLink Project, Australia, ABB (+/- 150 kV, 220 MW, 180 km polymer land cables) Cross Sound Cable, USA, ABB (+/- 150 kV, 330 MW, 40 km polymer cables)
2003	Troll 1&2 Project, Norway, ABB (+/- 60 kV, 80 MW)
2006	Estlink Project, Finland-Estonia, ABB (+/- 150 kV, 350 MW, 74/31 km of sea/land polymer cable)
2010	TransBay Cable, USA, Siemens (+/- 200 kV, 400 MW, 85 km polymer subsea cables) Caprivi Link, Zambia-Namibia, ABB (350 kV mono, 300 MW, 950 km OH Line)
2011	Valhall Offshore, Norway ABB (150 kV mono, 78 MW, 292 km of subsea polymer cable)
2012	East-West Interconnection, Wales-Ireland, ABB (+/- 200 kV, 500 MW, 75/186 km of land/sea polymer cables) Borwin Alpha, Germany, ABB (+/-150 kV, 400 MW, 125/75 km of sea/land polymer cable)
2013	Borwin2, Germany, Siemens (+/- 300 kV, 800 MW) Dolwin1, Germany, ABB (320 kV, 800 MW, 75/90 km of sea/land polymer cables) Helwin1, Germany, Siemens (250 kV, 576 MW)

2014	Mackinac, USA, ABB (70 kV, 200 MW, back to back) Skaggerak4, Norway-Denmark, ABB (500 kV mono, 700 MW, 140 km Mass Impreg. cable) South West Link, Sweden-Norway, Alstom (+/- 400 kV, 1400 MW, 110 km of underground polymer cable) Sylwin1, Germany, Siemens (+/- 320 kV, 864 MW, 210 km polymer cables) INELFE, France-Spain, Siemens (+/- 320 kV, 2000 MW)
2015	Troll 3&4, Norway, ABB (+/- 66 kV, 100 MW, 70 km subsea polymer cables) Helwin2, Germany, Siemens (+/- 320 kV, 690 MW, 131 km polymer cables) BorWin2, Germany, Siemens (+/- 300 kV, 800 MW, 75/125 land/sea polymer cables) Dolwin2, Germany, ABB (+/- 320 kV, 900 MW, 45/90 km of sea/land polymer cables) Nordbalt, Sweden-Lithuania, ABB (+/- 300 kV, 700 MW, 400/50 km of sea/land polymer cables)

VSC technology is now well established and proven in reliable service for more than 15 years. The technology has been proven successful at progressively higher voltage levels and power levels, and the technology has demonstrated distinct performance and cost advantages when applied to low-strength systems with weak reactive support, and when applied in conjunction with HVDC cable systems.

VSC projects now in service operate successfully at the **+/-** 200-kV level contemplated for the Maritime Link Project. The highest power level for any **+/-** 200-kV VSC project commissioned to date has been 400 MW for the 2010 TransBay cable in California, and 500 MW for the recently completed East-West Interconnection between Wales and Ireland.

At 500 MW and **+/-** 200-kV operating voltage, the Maritime Link will require delivery of 1,250 amperes of direct current from the AC/DC converters. Several monopolar and bipolar VSC projects currently in the planning stage or under construction will equal or exceed this 1,250 ampere level, at voltage levels ranging from +/- 150 kV to +/- 320 kV. At voltage levels above 400- kV and power transfer levels greater than 1,000 MW, LCC technology remains the industry standard for projects. VSC technology has become the industry standard at DC power levels from 200 MW to 700 MW, including several publicly announced HVDC-VSC projects around the world that plan to operate at or below a 700 MW and one 1,000 MW are also planned. When short circuit ratios or fault currents of an electrical system are low, VSC technology can be a more cost effective solution than LCC, which is the case with the Maritime Link.

The total cost of conversion, coupled with VSC's demonstrated success at the planned voltage level of +/- 200 kV, and a number of demonstrated operating advantages presented in Section 3.2.3, indicate that VSC technology is the appropriate choice for the Maritime Link. This technology is technically feasible for this application, and is the least-cost converter solution.

For the submarine cable system, NSPML has specified two cable insulation technologies, and has invited proponents to recommend the insulation technology of their choosing, with supporting technical specifications to prove the long-term viability of the proposal. As described in Section 3.2.4, the usual choices for HVDC cable projects are MI insulated cables and XLPE insulated cables. MI cables have been the workhorse for HVDC submarine cable applications for many years, and still dominate the industry for cable projects at voltages above 200 kV, and for cable projects tied to Line-Commutated Converters. XLPE insulated cables are becoming more common in HVDC projects involving Voltage Source Converters, as referred to in Figure 3.6.

The project design team has designed the terrestrial transmission facilities and grounding lines using proven, industry-standard design techniques, incorporating transmission design standards from NL Hydro and NS Power, and transmission design techniques and software applications with longstanding proven industry track records. The design team has leveraged proven technologies in the design of these facilities, and all of these facilities are expected to meet the functional specifications for power transfer capability and reliability. The design of the AC substation expansion projects is based on existing standards and conventional design techniques. The equipment selected for installation in these switchyards has been in use for many years at these voltage and power levels, and no novel technologies are contemplated for these developments.

Design of the DC grounding sites is still underway, given that the selection of proposed grounding sites has yet to be finalized. The design team will design the grounding sites using proven technologies and design techniques. Completion of the design will require additional study and careful definition of tidal levels, sea floor bathymetry, variability of sea-water salinity, and on-shore and off-shore ground resistivity. The environmental review of these installations will also require additional studies. The results of these studies will influence the design of the grounding sites, but not their overall feasibility. The project design team is confident these shore grounding sites are technically feasible and will meet the functional specifications.

4.0 MARITIME LINK PROJECT COST ESTIMATES

The Regulations require that this Application include capital and operating cost estimates for the Maritime Link Project, including a proposed capital structure and return on investment.[21]

This section is responsive to this requirement, and should be read in conjunction with Appendices 4.01 - 4.03.

As noted earlier, the physical transmission and associated facilities that comprise the Maritime Link connecting the Nova Scotia Transmission System and the Newfoundland Island Interconnected System are a key component of the Maritime Link Project. Equally important are the Nalcor Transactions that are also part of the Project.

The Regulations contemplate that once the UARB has approved the Maritime Link Project, NSPML will then be entitled to recover all costs that it incurs in connection with the Project (Project Costs) from NS Power from time to time in accordance with the mechanism prescribed by the Regulations.[22]

4.1 Introduction

This section will discuss the various Maritime Link Project Costs and related matters for which UARB approval is sought in this Application and that will be included in the assessment to be set against NS Power, as follows:

- estimated capital costs to be included in rate base,
- capital structure,

[21] Paragraph 5(5)(d) of the Regulations
[22] See: Section 2, subsection4(2) and Section 8

- return on equity,
- interest costs,
- forecasted operating and maintenance costs and related reconciliation mechanism, and
- redispatch costs of NS Power's generation assets and incremental capital costs as may be required on NS Power's existing transmission system, net of transmission tariff revenues to be paid by Nalcor, relating to energy to be wheeled through Nova Scotia.

Additionally, this section discusses the conveyance of the Maritime Link to Nalcor at the end of the 35-year term.

This section also provides details regarding the recovery of costs of the Maritime Link Project from NS Power and Nova Scotia customers.

4.2 NSPML - Capital Costs and Rate Base

As described previously, the underlying principle of the Maritime Link Project is that in exchange for 20 percent of the energy from Muskrat Falls over the agreed-upon term, NSPML is responsible for 20 percent of the LCP Phase 1 and Maritime Link facilities' costs (the 20 for 20 Principle).

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

4.3 Current Capital Cost Estimate

Currently, the estimated LCP Phase 1 and Maritime Link facilities' costs are comprised of (a) Nalcor's Decision Gate 3 capital cost estimate of $6.2 billion for Muskrat Falls Generation Station, the Labrador Transmission Assets, and the Labrador-Island Transmission Link, plus (b) NSPML's Decision Gate 2 capital cost estimate of $1.4 billion for the Maritime Link facilities, or a total of $7.6 billion. In accordance with the commercial agreements, NSPML's Decision Gate 3 estimate will be finalized by October 1, 2013.

As such, given the 20 for 20 Principle and the current total of LCP Phase 1 and Maritime Link facilities' capital cost estimate of $7.6 billion, the Maritime Link Project capital costs are $1.52 billion, and this is the first element of the rate base that NSPML is asking the Board to establish in this proceeding. When its Decision Gate 3 capital cost estimate for the Maritime Link facilities is finalized, NSPML will update this Project capital cost estimate.

The $6.2 billion capital cost estimate relating to the LCP Phase 1 is fixed pursuant to the commercial agreements with Nalcor. This means that 80 percent of the estimated capital cost of the Maritime Link Project is now fixed and not at risk of change for customers. This is a very positive component of the Project and should assure the UARB that the risk of cost increases is mitigated.

NSPML's current Decision Gate 2 estimate of the capital cost for the Maritime Link facilities is a P50 estimate; its current P90 estimate of these costs is $1.5 billion and its P97 estimate is about $1.7 billion. These estimates, developed using Monte-Carlo based probabilistic methodologies, reflect, respectively, a 50 percent, a 90 percent and a 97 percent likelihood that the final capital costs will be that amount or less.

The specific components of the current P50 estimated capital cost of the Maritime Link facilities are shown in Figure 4-1.

Figure 4-1

Maritime Link Facilities P50 Cost Estimate	$M
Transmission assets	$350
Converter stations and related infrastructure	450
Marine	300
Project management	100
Other costs	200
Total, as spent	**$1,400**
As spent including estimated escalation / inflation / contingency	

Consequently, using a range of capital costs for the Maritime Link facilities of $1.4 billion to $1.7 billion, NSPML estimates the total capital cost for the Maritime Link Project should fall within the range of $1.52 billion to $1.58 billion.

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.

Figure 4-2

<u>Total Maritime Link Project Estimated Capital Costs (before AFUDC)</u>			
	ML cost <u>$1.4 billion</u>	**ML cost <u>$1.5 billion</u>**	**ML cost <u>$1.7 billion</u>**
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

From Figure 4-2, it is clear that a difference may arise between the capital cost estimate of the Maritime Link facilities and 20 percent of the capital cost estimate of the LCP Phase 1 and Maritime Link facilities combined. The table assumes that this difference will be addressed using cash compensation between NSPML and Nalcor (the 20 percent true-up). An alternative to cash compensation is discussed in Section 4.4.

An allowance for funds used during construction (AFUDC) of approximately $230 million will be added to this base cost. AFUDC represents the capitalization of financing costs during the construction phase of the Project.

4.4 Compensation

The calculations above assume that the 20 percent true-up is addressed via an additional capital cost to the Project. The Sanction Agreement (Appendix 2.15), however, provides two options in this regard as described below.

If the capital cost estimate of the Maritime Link facilities at Decision Gate 3 is $1.4 billion and as a result NSPML's 20 percent share of the estimated capital cost of the LCP Phase 1 and Maritime Link facilities is $1.52 billion, two options are available to NSPML with respect to compensating Nalcor for the difference:

1. Compensate Nalcor via a cash payment of $120 million, or

2. Compensate Nalcor by accepting less energy from Muskrat Falls on a pro-rata basis based upon total capital cost. To illustrate: since $1.4 billion is 18.4 percent of the total capital cost estimate of the LCP Phase 1 and Maritime Link facilities of $7.6 billion ($6.2 billion plus $1.4 billion), NSPML could choose to accept 18.4 percent of the energy from Muskrat Falls rather than pay Nalcor the $120 million differential.

If the capital cost estimate of the Maritime Link at Decision Gate 3 is $1.5 billion and as a result NSPML's 20 percent share of the capital cost estimate of the LCP Phase 1 and Maritime Link facilities is $1.54 billion, NSPML again has two options available to compensate Nalcor for the difference:

1. Compensate Nalcor via a cash payment of $40 million, or

2. Compensate Nalcor by accepting less energy from Muskrat Falls on a pro-rata basis based upon total capital cost. To illustrate: since $1.5 billion is 19.5 percent of the total capital cost estimate of the LCP Phase 1 and Maritime Link facilities of $7.7

billion ($6.2 billion plus $1.5 billion), NSPML could choose to accept 19.5 percent of the energy from Muskrat Falls rather than pay Nalcor the $40 million differential.

In the event that the DG3 capital cost estimate for the Maritime Link facilities is $1.7 billion, which is more than 20 percent of the total capital cost estimate of the LCP Phase 1 and Maritime Link facilities, then Nalcor would have the same options to consider in order to compensate NSPML.

The $1.52 - $1.58 billion to be included in NSPML's rate base will be depreciated over a 35-year period, in keeping with the commercial agreements. The Maritime Link is built to last 50 years and will be conveyed to Nalcor for $1 at the end of the 35th year, unless the parties decide to extend the term of their agreement. Since NSPML will be incurring capital costs relating to facilities with an estimated life of 50 years but owning them for 35 years, NSPML will receive additional energy in the first five years of the Project – approximately 240,000 megawatt-hours per year.[23]

Essentially, this amount is determined by extending the Maritime Link Project financial model from 35 to 50 years and determining the levelized price of the energy in that 50-year scenario (as if NSPML remained the owner of the Maritime Link Project for the full 50 years). The 50-year levelized price is then compared to the levelized price in the 35-year model. To equate the two levelized prices, the optimal amount of Supplemental Energy per year in each of the first five years is determined. Given current estimates, the annual Supplemental Energy for each of the first five years of operation is 240,000 megawatt-hours. This calculation is intended to put NSPML and Nova Scotia customers on an equal footing as if the contract with Nalcor was for 50 as opposed to 35 years.

[23] Schedule 4 of the Energy and Capacity Agreement, attached as Appendix 2.03, establishes the method for determining the amount of this Supplemental Energy.

If at any time the Project Costs exceed the estimated costs as approved including the variance, NSPML will consider seeking approval from the UARB to recover such additional capital costs, as contemplated by Subsection 6(3) of the Regulations.

4.5 Capital Structure

Because this is NSPML's first application to the UARB, approval of a capital structure and rate of return on equity (ROE) is requested, as contemplated by the Regulations.

NSPML is requesting the following capital structure for purposes of setting AFUDC rates during the construction period (Phases 1, 2 and 3) and for purposes of setting revenue requirements during the operating period (Phase 4):

1. Phase 1: From 2011 (the start of development activities) until the date that external debt financing is arranged and approved by the Government of Canada (expected to be completed by December 31, 2013), all Project Costs will be funded 100 percent by equity. This is a requirement of the Government of Canada as outlined in the Federal Loan Guarantee (FLG) term sheet.[24] It is also consistent with traditional project-financing arrangements.

2. Phase 2: Subsequent to Phase 1, all incremental Project Costs will be funded 100 percent by debt until such time as NSPML has a 70 percent debt and 30 percent equity capital structure. For clarity, the FLG allows for Project lenders to advance debt without further equity investment until the 70 percent debt and 30 percent equity capital structure is achieved. Again, this is consistent with the FLG term sheet.

3. Phase 3: Subsequent to Phase 2 and up to completion of construction, all incremental Project Costs will be funded using a 70 percent debt and 30 percent equity ratio.

[24] See Appendix 4.03: Section 4.14 of the FLG term sheet.

4. Phase 4: Subsequent to Phase 3 and for the remainder of the Project (the operating period), a capital structure of 70 percent debt and 30 percent equity will be maintained.

While NSPML will endeavor to maintain the capital structures as requested above, given that the FLG imposes a minimum equity requirement of 30 percent, and given the practical challenge to balance debt and equity levels with such precision as capital costs are being incurred and as debt payments are being made, flexibility to allow for equity up to 35 percent is required. 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.

The approach to financing the Maritime Link Project will be similar to traditional project financing, with the addition of the Government of Canada playing a role in the financing structure given their support by way of the FLG. Project financing is available when the assets being financed are directly pledged as security for the loan. It is expected that NSPML will arrange most of the debt at the beginning of the Project, and will repay it over the Project's 35-year lifespan. The terms of the FLG and the nature of project financing establishes and dictates a capital structure that will be maintained through the life of the project. This provides security and stability to customers, lenders, the Government of Canada as guarantor, and Emera Inc. as shareholder.

Kathleen McShane of Foster & Associates Inc., who has previously appeared before the Board as an expert on matters related to capital structure and return on equity, provides additional supporting evidence for this proposed capital structure in Appendix 4.02.

4.6 Rate of Return on Equity

NSPML is also seeking the Board's approval of a rate of return on equity and an adjustment mechanism which will apply for each year of the period of construction and up to and including the first full year of operation. NSPML is requesting such a mechanism given the need for NSPML to be raising capital during this period and the need for clarity of the rate of return profile during this critical period. NSPML is also seeking confirmation of its rate of return on equity during the first full year of operation to provide clarity on the first year of revenue requirement that will be required to fund the Project Costs.

The rate of return on equity being requested is outlined below:

- For 2011 through to and including 2013, a rate of return on equity of 9.10 percent is requested. In addition to the supporting evidence of Kathleen McShane (as provided in Appendix 4.02), NSPML notes that the total cost of equity financing will be relatively low given the low equity thickness of 30 percent.

- During each year of the remainder of the construction period (currently expected to be 2014, 2015, 2016 and 2017), and for the first full year of operation (currently expected to be 2018), NSPML seeks a rate of return based upon a formula that is linked to the long-term A-rated Canadian utility bond yield. The evidence of Kathleen McShane more fully describes the formula being sought and the timing upon which each annual rate will be determined.

- NSPML requests that the construction financing costs (debt and equity, as applied through the first three phases outlined above) be included in the rate base as AFUDC.

- For the years subsequent to the first full year of operation, NSPML will seek a reasonable rate of return on equity with the UARB based upon market conditions at the time.

- It is important to note that the only return on equity that will be earned as it relates to the Project will be earned by NSPML. NS Power and Emera will not be receiving any other return on equity relating to the Project.

4.7 Interest Costs

4.7.1 Financing Environment

Designing and building a project of this magnitude will require the funding and support of both equity and debt markets, given the level of capital investment necessary to complete the Project. Capital market investors will need to be compensated for exposing their capital to risk relative to the opportunity cost of other similar investments or projects currently available to them. NSPML must offer returns to investors comparable to those achieved on competing investments of similar risk.

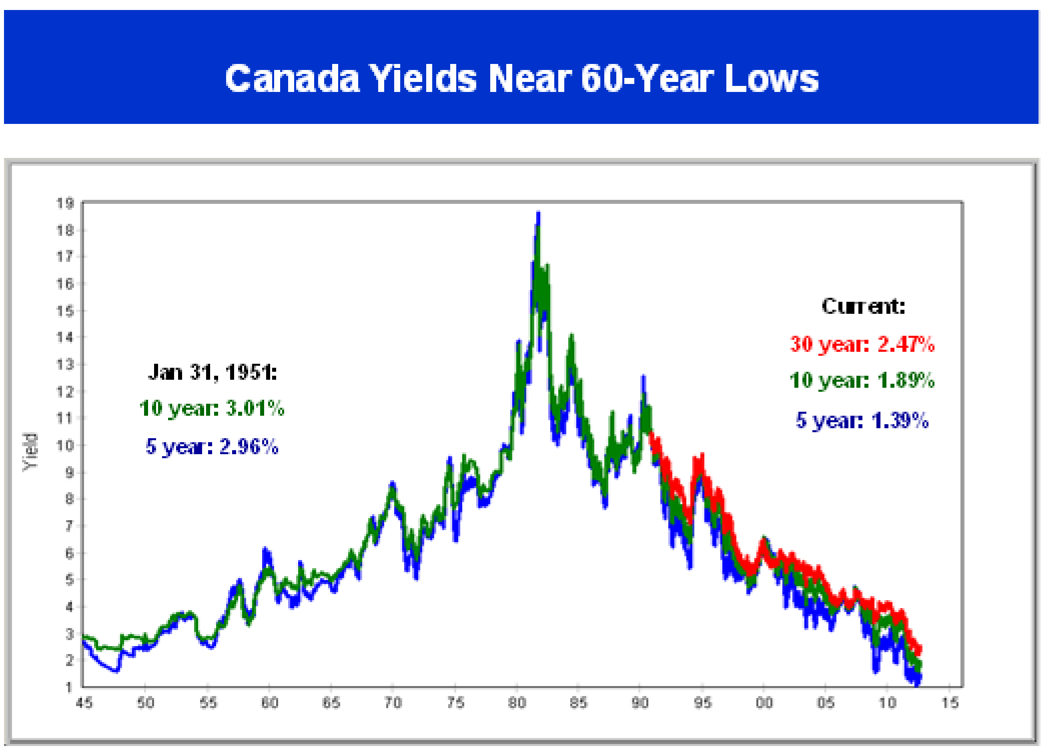
The cost of debt required by institutional investors or lenders will be influenced by the investment environment and the inherent risk of the Project. The investment environment reflects the surrounding market forces and the compensation received for similar transactions. The inherent risk and ultimately, the cost of the debt, reflects the comfort gained by institutional investors during independent due diligence review and a debt rating. Lenders will consider both the rating of the Project and any risks that are deemed to be specific to the Project. In the case of the Maritime Link Project, the Canadian government’s provision of a Federal Loan Guarantee (FLG) will have an important influence on how lenders price project risks and will result in a significant reduction in the interest rate spreads and thus the cost of interest to Nova Scotia customers.

4.7.2 Canadian Interest Rates

The cost of debt for corporations typically involves a corporate addition, or “spread,” to an underlying benchmark government bond. In Canada, corporate debt is more expensive than sovereign (government) debt. The Maritime Link Project will most closely resemble a project debt financing. The spread charged will be based upon the creditworthiness of the Project, which will largely be driven by the clarity and certainty of the regulated recovery of costs and the terms of the FLG.

In the Canadian market, Government of Canada bonds serve as the underlying benchmark for corporate debt financing. As shown in Figure 4-3, the yields for Government of Canada bonds are near 60-year lows.

Figure 4-3



Source: PC Bond Index

Given the term of the Maritime Link Project, the underlying benchmark bond for the debt financing will likely be Government of Canada 30-year bonds. As illustrated above, Government of Canada yields currently stand at historically low levels, resulting in lower financing costs and thus total Project Costs, and support the premise that now would be an ideal time to finance.

4.8 Federal Loan Guarantee

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. A Federal Loan Guarantee should have the effect of encouraging institutional lenders to price this debt financing as if the Maritime Link Project were more similar to a federal crown corporation like Canada Post or the Canadian Mortgage and Housing Corporation. With a Federal Loan Guarantee, institutional lenders will focus on the strength of the guarantee during their due diligence.

A guarantee is a legally enforceable promise in which the guarantor (Government of Canada) agrees to fulfill the obligations of another party (NSPML) should it fail to honour its debt agreement with a third party (institutional lender). The intent of such a guarantee, in this case the Federal Loan Guarantee, is to enhance credit by substituting the Government of Canada credit worthiness for that of NSPML. The goal of credit substitution is achieved through well drafted guarantees that address the core principles established by the rating agencies for this specific purpose.

The Government of Canada has stated its willingness to provide such a guarantee in the interest of supporting what it considers to be a transformational project for the Atlantic Canadian region that also reduces the country's dependence on fossil fuel. The commitment of the Government of Canada to the project is best reflected in a guiding principle of the Federal Loan Guarantee documented in the recently executed term sheet (Appendix 4.03) which provides that full credit substitution in conjunction with the Federal Loan Guarantee Agreement must be achieved. This is further defined as all parties privy to the agreement working together to ensure that the project debt receives Canada's AAA rating.

To summarize, the combination of existing low market interest rates, the even lower rate of financing that is available due to the FLG and the relatively low level of equity capital financing makes this a tremendous time to finance this Project.

For purposes of setting AFUDC rates during the construction period, NSPML is requesting that the interest component of AFUDC be estimated by NSPML prior to the beginning of each year. This is similar to how the rate of return on equity component of AFUDC will be determined prior to the beginning of each year.

4.9 Separate Legal Entity

As has been stated previously, this application is being made by NSPML, an affiliate of NS Power and Emera. A separate corporation (a "special purpose entity") is a requirement of the Federal Loan Guarantee.[25] The reasoning for a separate legal entity is explained below.

NS Power, like many Canadian utilities, has access to unsecured debt financing. Canadian institutional investors are willing to lend on an unsecured basis due to the regulated nature of the cash flow streams stemming from the cost recovery framework for NS Power's underlying assets or rate base. NS Power continues to successfully avail itself of the unsecured debt financing market under its existing trust indenture. NS Power presently has approximately $1.95 billion outstanding in long-term debt that is unsecured.

[25] See Appendix 4.03: Section 1.4 of the Federal Loan Guarantee term sheet.

In the case of a single asset project and business like the Maritime Link Project, institutional investors typically expect some form of security, as well as, assurances that the principal of the debt will be fully repaid over time. As referenced earlier, NS Power currently has no secured debt. It is worth noting that NS Power has no amortizing debt as well.

The support of the Government of Canada via a loan guarantee is an extremely important feature of the Maritime Link Project that will directly benefit Nova Scotia customers and reduce the cost of the Maritime Link Project by more than $250 million (more than $100 million on a net present value basis). Under the terms of the FLG, the Maritime Link Project debt will require principal repayments over the life of the project and that priority security over the related assets, shares and contracts shall be granted. Creating a separate legal entity to develop the Maritime Link Project facilitates the ability to address these requirements and ensure the loan guarantee is structured to achieve the maximum benefit for Nova Scotians.

Due to the unsecured nature of NS Power's long-term borrowing program, NS Power's trust indenture provides existing bondholders with protection or rights that both inhibit and restrict NS Power's ability to grant the requested priority security to the Government of Canada. Specifically, the ability to grant priority security over the Maritime Link Project assets solely to the Government of Canada is not permitted due to a negative pledge provision requiring security to be shared equally and ratably among all bondholders. Amending NS Power's trust indenture to allow the Maritime Link Project to accommodate the Government of Canada's request for priority security over the Maritime Link assets would require the consent of the existing bondholders. The amendment process for the NS Power indenture would require a formal bondholder solicitation. Ultimately, the bondholders may not agree to this amendment or may require a large fee to approve such an amendment as is industry practice when a company seeks to amend its trust indenture. Not receiving this approval or the cost at which this approval may be received will increase both the financing risk and borrowing costs for the Project and would be contrary to the objectives of the FLG. Given that the Government of Canada as guarantor requires that the assets, shares and contracts of the Maritime Link Project be provided as security, and that principal repayments be made over the life of the Project in exchange for the granting of the guarantee, a separate entity is necessary. Emera has experience with secured and amortizing debt financings within its group of companies and unlike NS Power, this type of structured debt financing would not be inconsistent with its borrowing approach. Emera's trust indenture (which extends to NSPML) specifically contemplates non-recourse financing and this also affords Emera the ability to successfully "ring-fence" the project from any potential, but as yet unidentified, negative repercussions that may result from a default.

Additionally, a separate entity will ensure that NS Power is not at risk for any cross defaults associated with the Project. A separate entity will facilitate the tracking of required credit ratios that will be important to lenders and rating agencies in both companies.

4.10 NSPML - Operating and Maintenance Costs

Although NSPML is not seeking approval in this Application of specific operating and maintenance ("O&M") costs (which will be incurred after the Project has been constructed), a forecast of this information is being provided to assist the Board and stakeholders in understanding the impact of these costs on the revenue requirement that will eventually be assessed against and paid by NS Power, as contemplated by the Regulations.

Consistent with the 20 for 20 Principle discussed earlier in the context of capital costs, since NSPML is receiving 20 percent of the total energy that Muskrat Falls provides, NSPML has conceptually agreed to pay 20 percent of the total O&M costs for the LCP Phase 1 and the Maritime Link facilities.

This sharing of the O&M costs is structured as follows. Nalcor and NSPML have agreed that for the 35- year operating period, Nalcor will estimate O&M costs for the LCP Phase 1; while NSPML will estimate O&M costs for the Maritime Link facilities. O&M includes not only annual operating expenses, but also sustaining capital needed to maintain the assets using good utility practice.

The Nalcor and NSPML estimates are added together and 20 percent of those combined estimates constitute the "20 percent O&M Cost Estimate". For each year in the 35-year period, the parties will compare the Maritime Link facilities O&M Cost Estimate with the 20 percent O&M Cost Estimate. The difference between the Maritime Link facilities O&M Cost Estimate and the 20 percent O&M Cost Estimate will constitute the "O&M Annual True-Up".

The parties will then calculate the net present value (NPV) of each of the O&M Annual True-Ups (whether positive or negative). The combined NPV of those amounts will result in a one-time payment, either from Nalcor to NSPML, or from NSPML to Nalcor.

The parties expect this transaction to occur shortly after construction of the projects is completed. Both parties will carry out appropriate due diligence prior to any true-up payment. NSPML expects that the accounting treatment for this true-up payment will be to treat it as a regulated liability or asset to be amortized over 35 years.

If this one time O&M True-Up results in a payment from NSPML to Nalcor, NSPML requests that such a payment constitute a Project Cost. If this O&M True-Up results in a payment from Nalcor to NSPML, such receipt by NSPML will serve as a benefit to Nova Scotia customers.

For greater clarity, after this true-up payment is made, there will not be any further comparison of O&M costs between NSPML and Nalcor. From that time onward (during the 35-year operating period), only the direct O&M costs of the Maritime Link facilities will be recovered from Nova Scotia customers via assessments against NS Power as described below and as approved by the UARB from time to time.

4.11 Nova Scotia Power System Costs

Via the Agency and Service Agreement between NS Power and NSPML, attached as Appendix 8.01, NS Power has agreed to comply with specific provisions of the commercial agreements between Emera and Nalcor. To enable it to do so, 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.

4.12 Recovering the Costs of the Maritime Link Project from Nova Scotia Power

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[26]. 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

[26] Regulations, Subsection 4(2).

recover that approved assessment from time to time in respect of the Maritime Link Project through its rates.[27]

One of several advantages enjoyed by hydroelectric systems as compared to coal, oil, and natural gas-fired generating stations is that they are not subject to volatility in fuel prices. Once a hydroelectric system is developed, it takes only modest spending on operations and maintenance to keep the water flowing, generating electricity, and maintaining the transmission assets. As a result, the total costs of developing and operating the Maritime Link facilities are relatively predictable.

4.13 Total Project Costs to Customers

When these collective costs (including capital costs, operating and maintenance, return on equity, interest and taxes) are compiled, a revenue requirement is determined in the post-construction period. NSPML has prepared a detailed financial model that provides the forecast of all such costs during both the construction and operating periods – extending to 35 years post construction. The results from this model are included in Appendix 4.01. It is important to note that the revenue requirement relating to the recovery of Project Costs as outlined in Appendix 4.01 does not include the added benefits of having access to additional market priced electricity, as well as, fuel cost savings associated with the NS Block and the purchase of market priced electricity in NS Power, which results from the Maritime Link Project being in service.

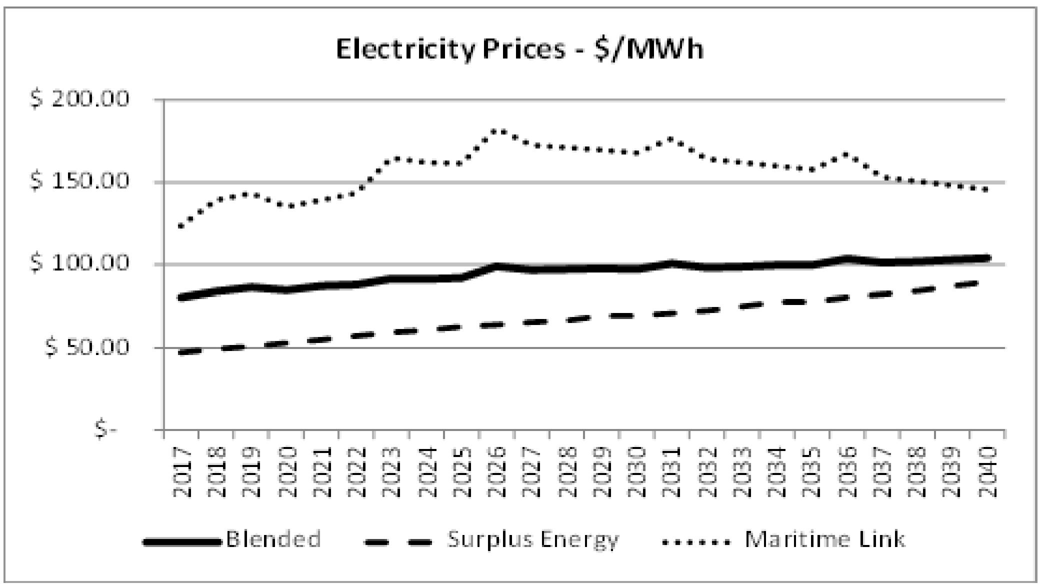
The net impact to Nova Scotia customers is a blending of the Project Costs with the purchase of market priced electricity and fuel cost savings associated with the NS Block and the purchase of market priced electricity.

[27] Regulations, Section 8.

This additional market priced electricity may be purchased either from Nalcor (Nalcor Surplus Energy) or from other energy providers. Additional information on this purchase is provided in Section 6.

Figure 4-4 illustrates the stable pricing of this blended cost of electricity arising from the Maritime Link Project. It does not include the additional benefit of fuel cost savings which will be experienced by NS Power.

Figure 4-4 Weighted Average Electricity Prices Per MWh



4.14 Conveyance of the Maritime Link at End of Term

The commercial agreements require NSPML to convey the Maritime Link to Nalcor at the end of the original term of 35 years for $1. Also, the Woodbine upgrades will be conveyed to NS Power at that time. As these are essential elements of the Nalcor Transactions and form part of the Maritime Link Project, the UARB's approval of the Maritime Link Project includes approval of these dispositions and any terms necessary to perfect the transfers. However, NSPML is a utility within the meaning of the *Public*

Utilities Act. As such, the specific approval of the UARB would normally be required before NSPML can sell, assign or transfer all or part of its utility undertaking.[28]

In the unique circumstances of the Maritime Link Project, which includes a contractually committed reversionary interest to Nalcor, as part of this Application, NSPML is specifically requesting, for greater certainty, the UARB's approval of these dispositions, based upon the terms contained in the commercial agreements, to the extent such approval is required.

4.15 Risk Management and Project Governance

NSPML has incorporated a Continuous Risk Management (CRM) process, to manage opportunities and control risks around Maritime Link Project Costs and schedule. The CRM process is an iterative process that identifies, analyzes, plans for, tracks, controls, communicates, documents and mitigates risks throughout the project development and construction process. This collaborative risk analysis takes place regularly, as part of the ongoing Project schedule, and also as specific needs arise. The risk management process is part of standard megaproject methodologies applied by industry leading experts.

An experienced project team has been in place through the initial phase of development, supported by external engineering, marine, legal and environmental resources. Investments in the (FEED) are consistent with project management best practices and have allowed the completion of the second phase of engineering appropriate for concept selection and an Association for the Advancement of Cost Engineering (AACE Recommended Practices no. 42R-08 and 17R-97) Class 3 project estimate. The AACE recommended practices provide a systematic approach to managing cost throughout the life cycle of a project through the application of cost engineering and cost management principles, proven methodologies, and technology in support of the management process.

[28] *Public Utilities Act*, RS 1989 c. 380, Section 62.

Engineering judgment and experience are utilized in the application of scientific principles and techniques to project planning and scheduling, cost estimating, economic and financial analysis, cost engineering, and cost and schedule performance measurement and change control. Cost and schedule reviews are conducted by internal team members and external industry experts as part of the methodology, to validate estimates. According to the AACE, a Class 3 project estimate purpose is for budgeting, authorization and control which is aligned with the Decision Gate 2 phase of the project methodology used for the Maritime Link Project. Project phases and methodology are described more fully in Section 7.

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[29] 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.

The FLG described previously, and ongoing communications with debt rating agencies, will solidify and maintain the project's debt financing ability.

Foreign exchange and commodity risks will be mitigated by the use of hedging methods when appropriate and as recommended by internal and external experts.

The NSPML team will work closely with Nalcor to plan, time, and execute a commissioning schedule for the Maritime Link transmission components. Commercial

[29] See Appendix 2.02 for a description of the Joint Development Committee, in the Maritime Link - Joint Development Agreement.

contracts for the elements of each project component will reflect these coordinated in-service commissioning plans.

Every phase of this project involves risk analysis, tracking, and mitigation to control project schedules, cost, and impacts. The commercial agreements governing this effort have outlined responsibilities of the parties and shared accountability for making the project successful. Both NSPML and Nalcor have incorporated project methodology and governance practices into their formal agreements with the objective of minimizing and mitigating risks. The scope and intricacies of the project design require a formalized approach to governance, a formalized partner structure, rigorous project processes, reinforced document and change management practices, and a clear, consistent plan to stay on schedule and within budgeted costs. Clear and consistent governance, as described above, will assist in ensuring that the Maritime Link Project will be able to deliver reliable, renewable energy to Nova Scotia.

5.0 LOWER CHURCHILL PROJECT PHASE 1 DESIGN AND COST ESTIMATES

The Regulations require that information concerning the capital and operating cost estimates for Muskrat Falls Generation Station (MF), the Labrador Transmission Assets (LTA) and the Labrador-Island Transmission Link (LIL), together with supporting engineering and design evidence, be provided. Information on the various costs and related matters associated with the three noted projects is provided in this section and in Appendix 5.01.

5.1 Nalcor Decision Gate 3 Costs

Nalcor has completed its engineering and design for phase three of the MF, LTA and LIL projects and have Sanctioned with a total project budget of $6.2 billion. After Sanction, as part of the 20 for 20 Principle, each party is responsible to execute the projects successfully within budget, having employed a rigorous project management process for design, budgeting and change management.

The Muskrat Falls Generation Station is a hydro development using a roller compacted concrete dam with a powerhouse designed for four 206 MW generators with an average capacity factor of approximately 68 percent. The powerhouse is located downstream of the 5,500 MW Upper Churchill Falls (CF) Hydroelectric development in Labrador.

The LTA connects the new hydro facility via a new dual overhead, two circuit 315-kV AC transmission system between the new switchyard and the CF site, providing a direct connection to the northern transmission facilities at CF.

The LIL will be a high voltage direct current (HVDC) transmission system operating at +/- 350 kV DC with a capacity of 900 MW, delivering power from MF to the eastern part of the island of Newfoundland at a location near Soldiers Pond. The overhead HVDC circuit will be connected to a bi-pole LCC converter set at each of the new switchyards in MF and Soldiers Pond, which serve the same functional purpose as the converters on the

Maritime Link but use LCC technology. At Soldiers Pond, there will also be three high-inertia synchronous condensers, which provide electricity system stability to the island system. The LIL will transition from overhead steel towers to underground cables at the shoreline of the Strait of Belle Isle (SOBI), where three HVDC submarine cables will then cross the SOBI and transition back to overhead on the northern peninsula of the island of Newfoundland. The LIL will also require similar shore grounding facilities as the Maritime Link, which are included as part of the design and will operate similarly to the Maritime Link.

The LIL, LTA and Maritime Link will in effect create an electricity loop between the CF and the Nova Scotia electricity system, for the first time connecting Newfoundland and Labrador to the North American electricity system.

The individual costs for each Nalcor project is provided in Figure 5-1, which represents the $6.2 billion budget for the LCP Phase 1 being developed by Nalcor.

Figure 5-1 Nalcor Project Costs

	$ billions
Muskrat Falls Generation Station	2.9
Labrador-Island Transmission Link	2.6
Labrador Transmission Assets	0.7
Total	**$ 6.2**

5.2 NSPML Due Diligence

An essential part of NSPML's risk management approach involves ongoing due diligence reviews of LCP Phase 1 activities. NSPML has been working with the Nalcor project team and representatives on key aspects of the LCP Phase1; including environmental assessment and planning, land rights, project controls, cost estimation labour planning, system design, engineering and project execution. This has included regular and special meetings to review project elements, as well as, workshops, where common elements of the projects are reviewed and assessed by representatives of NSPML and Nalcor. NSPML and its representatives have been provided direct access to information necessary for due diligence purposes, including individual interviews with Nalcor Project representatives to review the design and budget. Reports were reviewed by the NSPML team. These reports covered all aspects of the project design and estimate and include their findings, recommendations and conclusions.

NSPML reviewed hydrology data and the basis for LCP Phase 1's design assumptions, as well as estimates of the electrical energy output of a hydroelectric development at MF under various conditions substantiating the 4.93 TWh annual energy level. NSPML reviewed Nalcor's approach to determining project contingency through a review of Nalcor's risk assessments and mathematical analysis to determine appropriate contingency levels and rates of escalation for each element of the LCP Phase 1's scope. The current LCP Phase 1 milestone schedule was found to include reasonable and realistic schedule management methods and planning. NSPML looked at the project execution processes and resources which Nalcor has committed to achieve project goals in such areas as scope, safety, environmental performance, quality, cost management and schedule planning. Schedule, process and cost reviews will continue throughout the LCP Phase 1 and Maritime Link facilities. NSPML's Project Manager consults with the LCP Project Director on an ongoing basis to ensure consistency and collaboration in approach and in both project plans. Nalcor has engaged experienced project team members, using industry leading project management practices.

5.3 MHI Findings

Manitoba Hydro International (MHI) was retained by the Government of Newfoundland and Labrador to provide an independent review of the MF, LTA and LIL projects. MHI has the expertise to conduct an independent review based on their extensive experience in hydroelectric projects, HVDC systems and operations around the world. MHI is a wholly-owned subsidiary of Manitoba Hydro, an energy utility operating in Manitoba, Canada which operates hydroelectric facilities on the Saskatchewan, Winnipeg, Laurie, and Nelson rivers, as well as, thermal and diesel generating stations. MHI's focus is on electric utility consultation services for planning, design, construction, and operations management of generation, transmission and distribution, as well as, retail sales. MHI participates in and leads development and operational projects around the world such as; Due Diligence of Hydro Power Assets in Southeastern Asia, Due Diligence Review of African Generation and Distribution Assets, hydroelectric project development in Turkey and Operations and Maintenance training in Sub Saharan Africa, North America, Ghana, Canada, and West Africa.[30]

As a recognized industry expert, MHI's assessment provides a solid basis for confidence in the LCP Phase 1 schedule and costs, which aligns with industry standard practices as recommended by the AACE and also with the Maritime Link Project approach and methodology as described further in Section 7.

MHI's assessment report states the following:

> The Lower Churchill Project has utilized experienced consultants, well recognized independent construction specialists, and benchmarking of other recent projects to confirm constructability, productivity rates, and costs. This work, combined with the advancement of the design to the 40% level at the time of submission, provides a significant increase in confidence in the Decision Gate 3 schedule and cost estimate.[31]

There are key findings identified in the report which demonstrate the due diligence applied in load forecasting, highlight good utility practice in the integration studies, suggest minor improvements to the converter station designs, and confirm that a diligent

[30] Source: Manitoba Hydro International website, accessed January 17, 2013. http://mhi.mb.ca/projects
[31] MHI, Review of the Muskrat Falls and Labrador Island HVDC Link and the Isolated Island Options, page 56, October 2012, provided as Appendix 5.01

and appropriate approach was applied by Nalcor to arrive at the cost and schedule estimates.

Nalcor's estimating process provides the Cumulative Present Worth analysis which includes capital expenditures, operating costs, fuel costs, and the cost of purchased power.

MHI reviewed all of the Lower Churchill Project Phase 1 engineering design plans for technical and construction feasibility, as well as, cost and schedule reasonableness. With respect to the transmission design, the MHI report notes:

> …Nalcor's design approach, given the severity and wide range of weather cases found along the transmission line route, is a reasonable and cost effective methodology. (page 45)

Engineering, design and construction feasibility are reviewed and covered in detail in the report's section on the Strait of Belle Isle Marine Crossing. As stated by MHI in its report on page 54, with reference to the Muskrat Falls Generating Station, MHI concluded:

> The design and engineering conducted to date are appropriate for a Decision Gate 3 milestone.

Engineering, design, construction and project implementation have been reviewed and all conclusions indicate that this least cost option of an inter-connected island link is the best energy alternative.

6.0 ANALYSIS OF ALTERNATIVES TO THE MARITIME LINK PROJECT

The Regulations require an analysis of lowest long-term cost alternatives to the Maritime Link Project.[32] Having regard to the criteria and conditions by which the Project is to be reviewed and considered for approval by the UARB, this section of the Application, read in conjunction with the reports and other material found in Appendix 6.01 to 6.06, provides the required analysis.

6.1 Approval Criteria

6.1.1 Maritime Link Cost Recovery Process Regulation

The Regulations require that:

> 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 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.[33]

NSPML has approached the required analysis of alternatives by compiling the costs of the Maritime Link Project and comparing them with the costs of the alternatives. NSPML

[32] Paragraph 5(5)(f)
[33] The Maritime Link Act and Regulations can be found in Appendix 1.01

retained Ventyx, an ABB Company, to conduct the analysis. Ventyx used the long-term generation planning tool Strategist®, a software model developed by Ventyx. 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. Ventyx recently was contracted by the Atlantic Energy Gateway (AEG) participants to undertake a resource development optimization analysis for the Atlantic region power system utilizing the Strategist® model. 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 robustness of any given alternative must be considered in the analysis. Tests of robustness explore whether the chosen alternative remains the best option under different reasonable conditions. This means asking whether the low cost alternative continues to offer the lowest cost under various foreseeable conditions, such as changing fuel prices, or increasing or decreasing customer demand. For example, the alternatives analysis assumes a certain load forecast, but load forecasts can vary and so it is customary to test alternatives under different load forecasts. An alternative is robust if it is the lowest cost option within the bounds of the ranges of possible futures.

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 the manner in which NS Power has approached long-term planning in previous submissions to the UARB.

To be considered a viable alternative, each option must meet all of the criteria set out in the Regulations. A viable alternative must be consistent with the relevant standards, obligations and requirements under the *Electricity Act* and *Environment Act* of Nova Scotia, the *Canadian Environmental Protection Act*, and any associated agreements.

6.1.2 Electricity Act

The *Electricity Act* (NS) requires that each load-serving entity, such as NS Power and the municipal electric utilities, must provide 40 percent of its electricity sold from renewable generation by 2020. Under the current regulations, qualifying renewable generation includes:

(i) solar energy,
(ii) wind energy,
(iii) run-of-the-river hydroelectric energy,
(iv) ocean-powered energy,
(v) tidal energy,
(vi) wave energy,
(vii) biomass that has been harvested in a sustainable manner,
(viii) landfill gas,
(ix) any resource that, in the opinion of the Minister and consistent with Canadian standards, is able to be replenished through natural processes or through sustainable management practices so that the resource is not depleted at current levels of consumption.

In May 2011, the *Electricity Act* was amended to include hydroelectric energy as a qualifying form of renewable generation, whether produced inside or outside Nova Scotia. Then, on January 17, 2013**,** Nova Scotia proclaimed amendments to its *Renewable Electricity Regulations* that direct NS Power to meet the province's *Renewable Electricity Standards* (RES) by acquiring, directly or indirectly, 20 percent of the electricity generated from Muskrat Falls — as long as the Muskrat Falls Generating Station and its associated transmission systems have been completed, are in normal operation, and the UARB has approved an assessment against NS Power under the *Maritime Link Act* and its regulations.

6.1.3 Environment Act

The *Environment Act* (NS) establishes 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 (NOx) emissions must not exceed 14,955 tonnes per year by 2020.
- Mercury (Hg) emissions must not exceed 35 kg per year by 2020.

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 percent from 2010 levels.

6.1.4 Canadian Environmental Protection Act (CEPA)

The CEPA imposes federal greenhouse gas restrictions through to 2030. Regulations 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. The new federal regulations are in effect, and as described earlier, establish a path for GHG emissions reductions from coal units between now and 2030.

Nova Scotia has adopted regulations that place hard caps on total emissions from the electricity sector for each year between now and 2020. In September 2012, the province and Canada asked for public comment on a draft agreement that would extend Nova Scotia's hard caps to 2030. This equivalency agreement would achieve similar emissions targets as the new federal regulations, but without imposing specific closure dates based solely on plant age. Instead, NS Power could base the timing of its plant closure decisions on normal system planning considerations, while planning necessary investments in current and future generation. The 2030 carbon dioxide cap proposed in the draft federal-provincial agreement would limit carbon dioxide emissions from electricity production in Nova Scotia to 4.5 megatonnes — the same reduction that would be achieved by the 2030 plant closures mandated by the CEPA.

No available alternative method of complying with the regulations provides a lower long-term cost than the Maritime Link Project. It is important to note that even if the other options considered could have offered a comparably priced alternative, none bring the unique combination of benefits of the Maritime Link Project, which:

- increases rate predictability for electricity customers through long-term (35 year) fixed cost contract,
- provides greater long-term electricity security,
- offers a strategic transformational opportunity for enhanced access to competitive markets,
- offers access to large, new, renewable electricity supplies for a minimum of 50 years,
- offers specific quantities of renewable energy at a stable cost for 35 years,
- provides enhanced reliability,

- strengthens Nova Scotia's connection to the North American grid to prepare for and to take advantage of many future energy scenarios,
- supports the development of additional intermittent renewable energy resources in Nova Scotia, such as wind and tidal.

6.2 Alternatives Considered

In conducting this analysis, NSPML considered various options for complying with the criteria established by the Regulations, including several alternative generation sources:

- Natural gas
- Nuclear
- Biomass
- Tidal
- Wind
- Imported hydro from Newfoundland and Labrador (the Maritime Link)
- Other imported power (through a new transmission connection in New Brunswick)

Each of the above options was screened against a number of key attributes that are either required to meet the Regulations or are required when adding a generation source to Nova Scotia's electricity grid. As Figure 6-1 makes clear, the Maritime Link option meets all requirements, but all other options are challenged in one or more areas.

Figure 6-1 Key Attributes of Generation Sources Considered

	Maritime Link	Natural Gas	Nuclear	Biomass	Tidal	Wind	Other Import
Renewable	yes	no	no	yes	yes	yes	possibly
Carbon Dioxide Free or Carbon Neutral	yes	no	yes	yes	yes	yes	possibly
Firm Capacity	yes	yes	yes	yes	no	no	yes
Improves System Reliability	yes	yes	yes	yes	no	no	no
Commercially Available	yes	yes	no	yes	no	yes	possibly
Permitted in NS	yes	yes	no	limited	yes	yes	yes
Reduces Dependence on Coal	yes	yes	yes	yes	yes	yes	yes
Lowest Long-Term Cost	yes	no	no	no	no	no	no

The following sub-sections describe the generation source options considered. Each option was screened against key attributes to determine if it was a feasible option to meet the Regulations. After the initial screening, these options were determined to be the Maritime Link, Other Import and Indigenous Wind and were analyzed further in the Alternatives Analysis described in Section 6.3.

6.2.1 Natural Gas

To comply with Nova Scotia's *Renewable Electricity Regulations*, any alternative considered for 2020 must be a renewable resource. This eliminates natural gas as a stand-alone option in that time frame. Beyond 2020, natural gas may serve to back up wind generation, or it could help Nova Scotia meet its 2030 requirements. Gas generation, however, produces carbon dioxide and nitrogen oxide emissions. Those emissions would count toward the carbon dioxide and nitrogen oxide emissions limits established for 2020, 2030, and beyond.

Natural gas as a standalone option does not qualify to meet the 2020 *Renewable Electricity Standard.* It does emit, however, less carbon dioxide than an equivalent amount of coal generation so it could be considered as an option to meet greenhouse gas requirements.

Natural gas in the Maritimes currently comes predominantly from the Sable Offshore Energy Project and will come from Deep Panuke once production begins. Offshore Eastern Canada production is projected to continue declining, as these fields are depleted. Future offshore exploration and production costs are currently not predicted to be competitive with continental US (particularly Marcellus Shale) production.

The Liquefied Natural Gas (LNG) terminal at Canaport in Saint John, NB, is a third potential source for gas supply in the region. LNG imports at Canaport are expected to remain low. North American gas prices remain low relative to global LNG prices, so Canaport attracts very little imports.

Since the projected local production will not be sufficient to meet static Maritimes demand, current estimates are that by about 2025, there will be a need to import gas supplies into the Maritimes.

If Nova Scotia imports from Canaport, sufficient volume must be available and gas prices need to be high enough to bid LNG away from Europe. The Canaport LNG prices will be at higher prices relative to North American gas prices.

If Nova Scotia imports from the US, expansion of pipelines into New England sufficient to meet northern New England demand and Maritimes demand will be required.

Any future scenario that includes substantial volumes of gas as a key component of the generation mix will need to address the considerable cost of the fuel and lack of certainty with respect to supply as a significant risk.

For these reasons NSPML has eliminated natural gas as a feasible standalone option.

6.2.2 Nuclear Energy

As construction of a nuclear facility to produce electricity is currently prohibited by law for NS Power,[34] it is not considered to be a viable alternative. Nevertheless, NSPML retained Barra Strategies to prepare a report on the state of the nuclear industry in Canada to better understand whether there could be a viable nuclear option if the legal prohibition were not in place. The report is provided in Appendix 6.01.

It can be concluded from the report that the nuclear energy option is not viable for Nova Scotia at this time. Nuclear generating stations are usually 1,100 to 1,600 MW in size and can "only be absorbed into very large electrical grids in order to ensure the reliability of the electrical systems they serve. Typically, a 1,600 MW unit would require another 1,600 to 2,400 MW of fast-starting generation as "operating reserve" to maintain system stability in the event of a sudden reactor outage."[35] Units of this size could cost $12 to $18 billion. This scale of investment is beyond what would be viable for Nova Scotia electricity customers.

Smaller scale units in the 190 MW range have typically been used in naval applications.

> ..(t)here is growing interest in Canada in the development and deployment of Small Modular Reactors because of their smaller size and the belief that they can be deployed more quickly because of factory fabrication and modular

[34] Nova Scotia Power Privatization Act, RS, 1992, c.8.Paragraph 8(1)(a).
[35] Nuclear Energy, Patrick MacNeil, Barra Strategies, Appendix 6.01

> construction techniques. There have been no applications submitted to the Canadian Nuclear Safety Commission to develop a Small Modular Reactor.[36]

Barra Strategies also notes small modular reactors will very likely face the same licensing requirements as large scale units. There are five licenses required through a nuclear power plant's life cycle. The first is the license to prepare the site and this can take several years to obtain. Ontario Power Generation's Darlington Nuclear Generating Station was issued a license to prepare a site six years after applying. The experience with larger scale nuclear reactors and the lack of experience with smaller reactors makes it difficult to predict with any confidence the timeline and costs of deploying a small modular reactor in Canada until the Canadian Nuclear Safety Commission receives and processes the associated License application and a plant is actually constructed.

6.2.3 Biomass

In 2010, Nova Scotia's Renewable Electricity Plan[37] set out the limits pertaining to biomass:

> Government will approach the development of biomass for electricity production with caution. Electricity produced from co-firing biomass will play a role in meeting the 2015 target, but will undergo review for post-2015 use. To ensure sustainability, pending release of the Natural Resources Strategy, this plan caps new electricity generation from forest biomass at 500,000 dry tonnes (~600-700 GWh) above current uses. Co-firing in thermal plants is capped at 150,000 dry tonnes (150 GWh).

This cap accommodated the Port Hawkesbury biomass project (388 GWh) with some limited room for additional biomass generation.

[36] Nuclear Energy, Patrick MacNeil, Barra Strategies, Appendix 6.01
[37] Renewable Electricity Plan http://www.gov.ns.ca/energy/resources/EM/renewable/renewable-electricity-plan.pdf

The Renewable Electricity Plan concluded that further review of biomass for electricity production post-2015 was needed. The Plan noted that the use of biomass for electricity production was a contentious issue. The plan also noted that the pending Natural Resources Strategy was expected to provide new guidelines for the longer term use of biomass for electricity production beyond the levels permitted for 2015. Shortly after the release of the Renewable Electricity Plan, the Glube Report[38] was released. This report, "A Natural Balance", was the result of the Steering Panel, Phase II of the Natural Resources Strategy 2010; it provides recommendations for the third and final phase of the legislated process to develop a 10-year strategy for Nova Scotia's natural resources.

The Glube Report recommended that "the province view the current agreement between NewPage Port Hawkesbury Ltd. and Nova Scotia Power Inc. as a pilot project and carefully monitor its impact on forests over time, basing future decisions on those findings." Furthermore, the report specifically recommended that government:

> …exercise great caution in the use of biomass for power generation. There is ample evidence that our forests are already under considerable stress. Despite the need to reduce greenhouse gases, Nova Scotia does not have the wood capacity for biomass use to make much of a difference even provincially. It is counter-intuitive for the province to protect the environment by cutting down too many trees or reducing the quality of already thin and acidic soils. The province should instead encourage the exploration and expansion of other sustainable methods to generate power and, at the same time, methods to conserve energy and reduce demand.[39]

[38] The Department of Natural Resources commissioned a panel chaired by former Chief Justice Constance Glube to prepare a report and recommendations focused on four elements—forests, parks, minerals, and biodiversity—to inform the development of a Natural Resources Strategy. When the panel was commissioned, it was anticipated that the report would recommend enhanced or new rules, regulations, and guidelines for the harvesting of wood as the Strategy was also expected to consider the use of biomass for energy.
[39] A Natural Balance, Report of the Steering Panel Phase II, Natural Resources Strategy, April 2010 http://novascotia.ca/natr/strategy/pdf/phase2-reports/Steering%20Panel_FINAL.pdf

In 2011, the Department of Natural Resources released its natural resources strategy for Nova Scotia, *The Path We Share.*[40] The strategy indicated that clarification on the use of forest biomass for energy was one of the actions the government was committed to take. One of the actions taken by government to provide that clarification was to reduce the cap on forest biomass for new electricity generation from 500,000 dry tonnes to 350,000 dry tonnes. The strategy also reaffirms the Renewable Electricity Plan's cautious approach to the use of forest biomass for electricity production.

The Government's position on the use of forest biomass for electricity production is clear. There is no possibility of using forest biomass to meet any part of the 2020 RES, to say nothing of the requirements in 2030. For these reasons, biomass has been excluded as a viable alternative to the Maritime Link Project.

6.2.4 Tidal Energy

Tidal energy is a promising resource in Nova Scotia, but remains under development. Scientific studies have shown that the Bay of Fundy resource alone could provide over 2,000 MW of power through extraction of kinetic energy from tidal currents. There remains limited experience regarding the costs associated with tidal energy deployments. Early estimates range from $440 – 510/MWh. With economies of scale and technology innovation, it is estimated that these costs should eventually fall within the range of $100 –150/MWh, making tidal power a competitive option to other renewable energy technologies. Emera expects that tidal power could become commercial, on a modest scale, in 2020. Tidal energy projects will likely develop incrementally over time from this point forward before eventually achieving large scale installations. The early stage of commercialization is not expected to provide the quantity of energy and capacity required. Furthermore, an expectation that tidal energy will be available commercially in

[40] http://www.gov.ns.ca/natr/strategy/pdf/Strategy_Strategy.pdf

2020 is not sufficient guarantee to forego other options that will be available in 2020. For this reason, tidal has been excluded as a viable alternative to the Maritime Link Project.

6.2.5 Wind

Wind generation has increased greatly in Nova Scotia over the last 10 years, however, there is a practical limit to the amount of wind generation that can be added to Nova Scotia's electricity grid. Simply put, system stability requires additional sources of energy to back up wind generation when the air is calm. Coal-fired thermal plants, which form a major component of NS Power base load generation, are unsuitable for this purpose because they cannot respond quickly enough to the variability of wind.

Nova Scotia currently has 319 MW of installed wind capacity, with another 216 MW planned or committed for 2015. The planned wind capacity includes the Nova Scotia Renewable Electricity Administrator's recently announced wind projects totaling 116 MW, and the Community Feed-In Tariff (COMFIT) expectations[41] over the next few years.

To meet the *Renewable Electricity Standard* goal of 40 percent renewables by 2020 with additional wind resources, an additional 425 MW of wind power would need to be added to the system. Nova Scotia's total installed wind capacity in 2020 under this scenario would be 960 MW on a 3,096 MW system (assumes no deration of installed wind capacity). Wind would then constitute 31 percent of NS Power's installed capacity. In terms of total energy, wind would supply about 28 percent of the 10 terawatt hours that are sold in Nova Scotia every year. Beyond 2020, as load continued to grow, wind would continue to be added to comply with the 40-percent RES requirement.

[41] COMFIT expectations include 100 MW but are not included for purposes of planning to meet the RES. COMFIT projects that are built will be used as a margin of safety in meeting the future RES requirements.

Many jurisdictions, particularly in Europe, have added large amounts of wind generation to their electricity systems. These countries benefit from multiple interconnections to strong, stable grids. In Ireland, for example, the East-West Interconnector[42] is a 500 MW link being developed between Ireland and Wales. Ireland has achieved significant wind penetration levels: more than 5,500 GWh annually from more than 2000 MW of wind capacity. However, wind's intermittent nature requires Ireland to import electricity when the wind is not blowing, and export power when wind is produced at levels that the country cannot fully consume. Ireland's installed generation capacity was 9356 MW in 2012.[43]

Adding 425 MW of wind to the levels already committed in Nova Scotia to meet the Renewable Electricity Standard requirement would take the province beyond current wind penetration levels in countries like Denmark and Germany. In Denmark, wind constitutes 28 percent of the total installed generation capacity and wind energy accounts for 23 percent of electricity generation. Denmark has multiple transmission interconnections to Germany, Sweden, and Norway,[44] totaling almost 5,000 MW. In Germany, wind constitutes 18 percent of the total installed generation capacity and wind energy accounts for 7 percent of electricity generation. Germany has access to more than 4,200 MW of hydro resources and more than 6,700 MW of pumped storage[45] and it has 15 GW of interconnections to 9 countries, which will increase to 30 GW of interconnections by 2022.[46]

[42] The East-West Interconnector is a subsea cable of similar length to the Maritime Link, as well as, the same operating voltage and converter technology.
[43] http://www.eirgrid.com/media/All-Island%20GCS%202012-2021.pdf
[44] http://www.energinet.dk/EN/ANLAEG-OG-PROJEKTER/Generelt-om-elanlaeg/Sider/Elforbindelser-til-udlandet.aspx
[45] http://www.eia.gov/cfapps/ipdbproject/IEDIndex3.cfm
[46] Source: German Federal Ministry for Environment, Nature Conservation and Nuclear Safety, email communication, December 12, 2012

NS Power has a 300 MW interconnection to the rest of the North American grid. The hydro resources of the province total 400 MW, and there is no pumped storage. Access to fast acting thermal generation (like natural gas and combustion turbine units) is limited.

In a study on wind generation in the United Kingdom and Ireland, Garrad Hassan[47] noted that many important technical issues arise as the proportion of wind generation increases—both because of wind's variability, and because modern wind turbine technology is inherently non-synchronous. In principle, all these technical issues can be overcome, although possibly at high cost.[48]

Adding more wind beyond already committed levels would require additional interconnections to other jurisdictions, additional fast acting generation, the development of energy storage, or some combination of the three.

In conjunction with NS Power, NSPML has considered what additions to the Nova Scotia electrical system would be required to permit the introduction of additional wind while ensuring the reliable operation of the system. In other words, exactly what would be required to make wind a viable alternative to the Maritime Link Project? This analysis is presented in Appendix 6.02.

Garrad Hassan also notes that imperfect matching of wind production with electricity demand can produce situations in which system managers must require wind farms to curtail their production. As more wind is added to a system this curtailment effect becomes more pronounced. This has significant consequences for the economics of the wind farm. At these levels, if wind were producing at high levels during periods of low demand for electricity in Nova Scotia, wind could account for all of the energy used in the province, forcing other generation sources to back down to unsustainable levels, in

[47] Garrad Hassan is a renewable energy consultancy with 30 years of experience in the technical aspects of onshore wind.
[48] http://www.gl-garradhassan.com/assets/downloads/The_Limiting_Factors_for_Wind_Integration.pdf

turn causing them to be unavailable when energy demand requires their output. As Garrad Hassan cautioned,[49] wind producers in this scenario could be forced to curtail their farms during periods when potential wind production exceeds load requirements. This would hurt the economics of the wind farm.

Given the above and the unprecedented amount of energy that NS Power customers would be relying on wind for, NSPML views wind as a risky an option to meet the 2020 renewable targets. However, NSPML has, in conjunction with NS Power, developed a wind alternative for study as part of the lowest long-term cost alternatives analysis. This is the Indigenous Wind alternative. The details of this alternative are provided below in Section 6.3.2.

6.2.6 Other Import

NSPML has also considered whether power imported using the existing interconnection under a comparable firm long-term contract with a counterparty could be a lower cost alternative than the Maritime Link Project.

The connection between Nova Scotia and New Brunswick has operated since 1960. It helps stabilize the electricity systems of both provinces by enabling them to share capacity and reserve. NS Power has also used the connection for sales to, and purchases from, parties outside Nova Scotia. Electricity sales follow the open market approach that came with deregulation and the move to open access transmission tariffs in New England. Electricity prices in the New England market also influence sales between Nova Scotia and others in the market. Suppliers would typically assess the New England market before deciding whether to sell to a third party like Nova Scotia. Historically, New England prices have usually been higher than Nova Scotia’s production costs, making New England an attractive market for energy sales.

[49] http://www.gl-garradhassan.com/assets/downloads/The_Limiting_Factors_for_Wind_Integration.pdf

More recently, energy sales and purchases between Nova Scotia and New Brunswick have been constrained, as load growth in the Moncton area has restricted the amount of energy Nova Scotia could import. Overcoming these constraints would require significant capital upgrades.

In order to adequately compare an alternate import option to the Maritime Link Project, it needs to offer similar benefits, including the combination of firm renewable energy and the opportunity to purchase additional energy at market prices. It must be acknowledged however, that there is no existing or potential agreement in place with a third party to deliver this alternative. Nevertheless, NSPML has evaluated this alternative to serve as a basis for comparison. The Other Import Alternative is explained below in Section 6.3.3.

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. The assumptions used are provided in Appendix 6.03 and 6.04.

Based on the screening analysis described in Section 6.1, other alternatives were eliminated for the reasons described. Two alternatives to the Maritime Link required further analysis: Indigenous Wind and Other Import. These alternatives are described in Sections 6.3.2 and 6.3.3 respectively.

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.

6.3.1 Maritime Link Project

The Maritime Link Project begins in 2017 and operates for a 35 year term in the model. The estimated capital and operating costs, financing costs, taxes and return were included in the analysis of this alternative.

Details of this alternative are provided throughout this Application and specifically in Sections 4 and 5 and Appendices 4.01- 4.03 and 5.01**.**

A summary of the assumptions used for the Maritime Link Project are provided in Figure 6-2.

Figure 6-2 Maritime Link Project Key Assumptions

Value	Assumption
$1.52B	Capital Cost
70%	Percentage of rate base funded by debt
4%	Debt rate
9.5%	Rate of ROE during construction
10%	Rate of ROE during operations
9.2%	Transmission losses
October 1, 2017	Commercial Operation Date
895 GWh	Annual energy (before Supplemental Energy)
240 GWh	Supplemental Energy per year for the first 5 years

6.3.2 Indigenous Wind

A large amount of new wind capacity is required to meet the needs of the Nova Scotia system. It was necessary to explore the alternative as it was considered possible that with the appropriate support and infrastructure wind might be a viable solution.

Under the base load forecast, NS Power estimates that 425 MW of incremental wind generation are needed to achieve the RES requirements in 2020. This amount of wind accounts for the fact that there will be periods of time when wind is producing more energy than is required by customers. During these periods it is assumed that the wind is curtailed to meet system demand. This curtailment results in a decreased capacity factor for incremental wind farms as the wind farms are not able to produce during all hours. This negatively affects the economics of the wind farms and this is reflected in the analysis. See Figure 6-3 for further explanation. As the load forecast increases between 2020 and 2040, the amount of wind needed increases by a further 150 MW. This results in 1,110 MW of total wind on the Nova Scotia system.

Figure 6-3 Indigenous Wind Key Assumptions

Value	Assumption
$988M	Capital Cost [derived from a levelized cost of $80/MWh for 425 MW using the assumptions below]
62.5%	Percentage of rate base funded by debt
6%	Debt rate
9.4%	Average Rate of ROE
Jan 1 2019	Commercial Operation Date
$1/MWh	Variable O&M escalated at 2%/annum, 2011$
$30/MW/yr	Fixed O&M escalated at 2%/annum, 2011$
30-35%	Capacity Factor* * Base Load: 425 MW @ 35% & 150 MW @ 32% Low Load: 250 MW @ 30% Capacity factors for incremental wind take into account estimated curtailment. An hourly profile of the forecasted system load net of wind production was produced. Curtailment was assumed in any given hour if the resulting load net of wind was less than the minimum steam generation requirement. Capacity factors were reduced to include the decrease in wind production due to the estimated curtailment.
20 years	Expected Useful Life
80%	Redevelopment Costs as a percentage of original project cost

In conjunction with NS Power, NSPML has considered what additions to the Nova Scotia electrical system would be required to permit the introduction of additional wind while ensuring the reliable operation of the system. This analysis is presented in Appendix 6.02.

As outlined in the analysis presented in Appendix 6.02, should it be necessary for NS Power to meet the 2020 RES requirements predominantly with wind, significant integration costs can be expected which will be over and above the costs associated with the wind turbines and associated interconnection facilities.

The capital expenditures for these integration costs are expected to be within the ranges presented, for a given level of installed wind capacity, below in Figure 6-4.

Figure 6-4 Estimated Range of Capital Investments to Support Large Scale Wind Integration

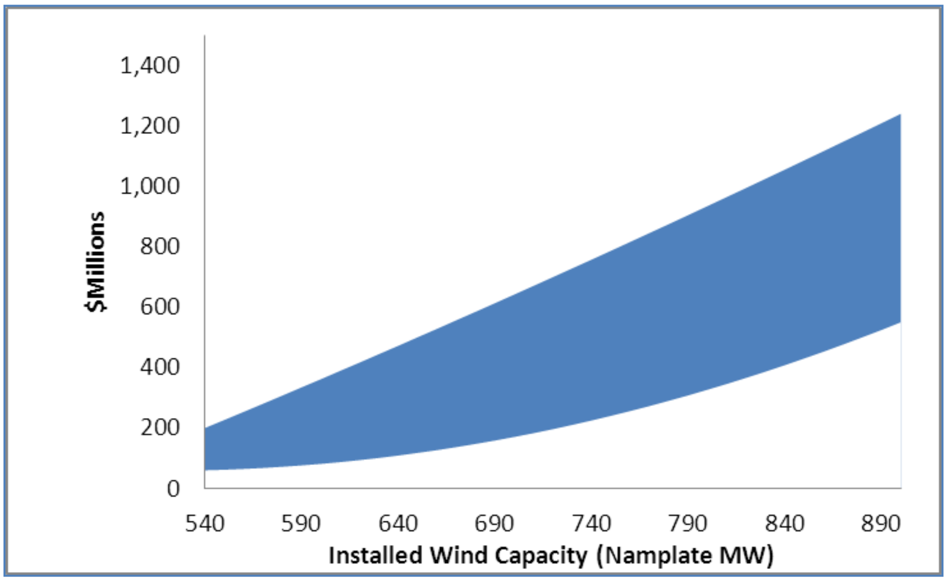


Figure 6-4 represents the system requirements that require some level of capital investment depending on the penetration levels of variable wind generation:

- Investment in new conventional generating capacity to maintain planning reserves and address needs for two shifting or fast acting generation.

- Investment in transmission upgrades within NS Power and developing stronger links with neighboring utilities to enhance system stability and reduce thermal generator cycling.

- Deployment of energy storage and load shifting programs to complement conventional generation for managing wind variability and wind ramps.

These are capital cost estimates and do not reflect operating costs related to wind integration such as thermal unit cycling costs, heat rate penalties, wind curtailment, and other related costs. It should also be noted that any costs associated with new or enhanced natural gas infrastructure to support a wind/gas option are not included in these capital costs and would be incremental to the estimates in Figure 6-4.

In order to give insight into the effect of these integration costs, the Indigenous Wind alternative was run initially without any integration costs added. This run included the capital and operating costs to build the necessary wind farms and connect them to the transmission system, but without any additional infrastructure to ensure stability of the system or fast start generation to follow the wind. This run incorporated wind, added in the appropriate size increments, as required to meet the Regulations.

The results of this run showed that for the Study Period, the Maritime Link Project was less expensive than the Indigenous Wind alternative in all sensitivity cases. This means that under the Indigenous Wind alternative, any investment in necessary integration costs will cause the Indigenous Wind alternative to be yet more expensive than the Maritime Link Project. The mid-point of the range of the capital costs for investment in transmission upgrades and deployment of energy storage and load shifting programs was used to estimate the integration costs required. Subsequent analysis included these integration costs which are required in order for Indigenous Wind to be a viable, comparable alternative to the Maritime Link project.

6.3.3 Other Import

An alternative import option to the Maritime Link Project must include similar benefits. These include access to firm energy and capacity and opportunity to purchase additional energy when it is economic. The option must also provide RES qualified energy.

Creating a firm path, and firm capacity-backed supply, would require transmission investment in Nova Scotia and other jurisdictions where the energy could originate. 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 report is provided in Appendix 6.05.

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[50] principles that Nova Scotia would be required to pay a minimum of $905 million. NSPML considered this along with estimates previously determined through other NSPML project work.

The other comparable option considered by WKM was a 500 MW upgrade from Nova Scotia into New Brunswick with sufficient upgrades to allow for a firm energy contract of 165 MW. Additional energy over and above the firm supply is anticipated to come from the New England market over transmission lines from Maine into New Brunswick.

A supply of energy and capacity from any provider would likely:

(a) reflect the pricing that is at least equivalent to the provider's next best offer, and

(b) be priced at what the market will bear.

Energy sourced outside of Nova Scotia is therefore expected to reflect New England market rates, plus applicable tolls through New Brunswick, and line losses. If importing from New England, Nova Scotia would be required to pay New England market prices

[50] Federal Energy Regulatory Commission.

for the energy, as well as, exit fees from the New England market. In addition, it is assumed that a firm transmission reservation from Maine into New Brunswick is made to secure a path for any energy purchases required by NS Power.

While WKM examined options for an Other Import alternative, only the lowest cost option that supplies the necessary quantity of energy was carried forward to the alternatives analysis. This was the full firm supply path, as described in the report (Appendix 6.05). Although the other alternative examined by WKM had a slightly lower capital cost ($1 billion versus $1.3 billion), when the price of energy from New England was included, the full cost of this option was higher.

A description of the Other Import assumptions is provided in Figure 6-5.

Figure 6-5 Other Import Key Assumptions

Value	Assumption
$676M	Capital Cost (includes AFUDC)
$22M	NBOATT Charges, escalated at 1% per year
60%	Percentage of rate base funded by debt
5%	Debt rate
10%	Rate of ROE
3.30%	Transmission losses through NB
Oct 1 2017	Commercial Operation Date
45 years	Depreciation
165 MW	Firm Contract Purchase
932 GWh	Annual energy (before Supplemental Energy)
500 MW	Transmission Link

When all costs are factored in, sourcing electricity through New Brunswick is not a more cost effective solution than the Maritime Link Project. To be a valid alternative, any low cost alternative must also satisfy the same criteria as the Maritime Link Project with respect to the *Electricity Act*, *Environment Act*, and the *Canadian Environmental Protection Act*. This means any Other Import supply of energy must come from renewable sources. A premium for renewable energy has not been included in the analysis, and a failure of the non-emitting import energy to qualify as renewable could eliminate or increase the cost of this alternative.

6.4 Results of the Analysis

NSPML, together with NS Power, conducted an alternatives analysis using a base set of assumptions. It is important to not only test for the low cost alternative under a base set of conditions but also to determine how the alternatives stack up under varying market conditions. Because the load forecast is a key input assumption in determining the least cost alternative, a low load case was also tested to consider the future where demand for electricity in Nova Scotia declines over time as opposed to growing as is predicted in the base set of assumptions. This was done to determine whether the least cost alternative, under the base input assumptions, would continue to be the least-cost alternative under the low load case.

Changing market conditions such as fluctuating gas and power prices could also impact the robustness of the least cost alternative. Sensitivities were also run against the base load case to explore the effect of higher and lower power and gas market prices on the outcome.

The results show that the Maritime Link Project is the lowest long-term cost alternative to meeting the requirements set out in the Regulations and remains the lowest long-term cost alternative under a range of possible future scenarios. Detailed results are included in Appendix 6.06.

Under base load conditions, Figures 6-6 shows that under the Study Period, the present value of the costs is $287 million less than the Other Import option. When compared with the Wind option, the Maritime Link Project costs up to $2 billion less.

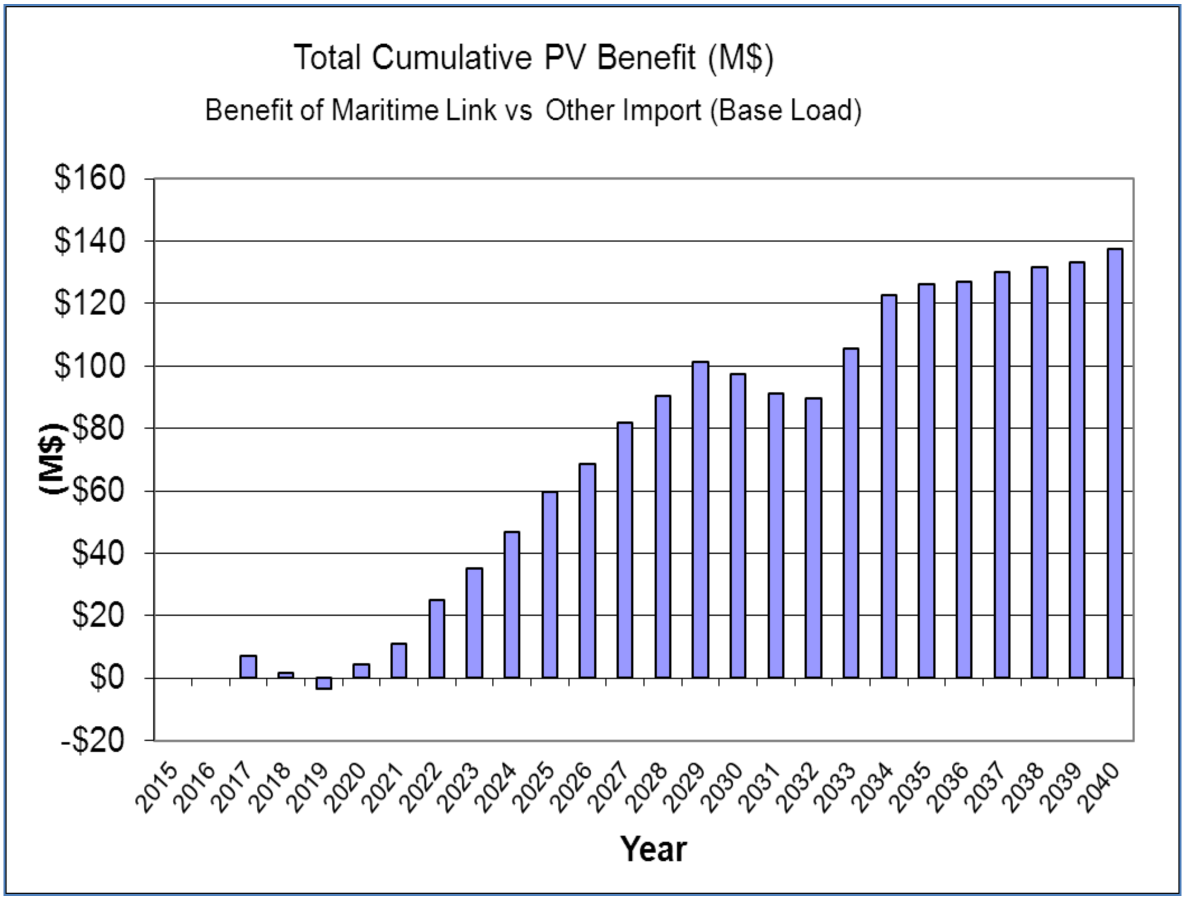
Figure 6-6 Comparison of Alternatives - Base Load

	Maritime Link	Other Import	Indigenous Wind*
Study Period ($M PV)	16,209	16,496	18,182

* *Wind costs in the Study Period reflect model results of; wind with no integration costs of $17,365 million plus integration costs of $817 million*.

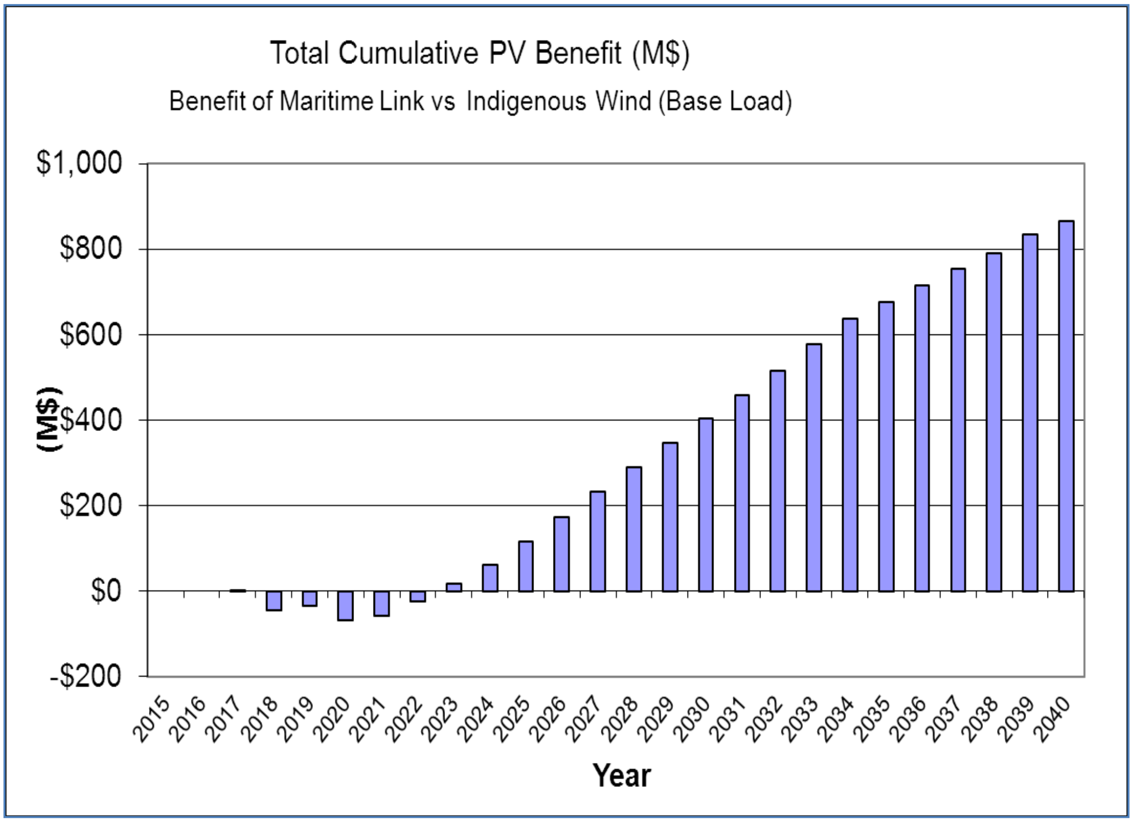
The cumulative benefit per year of the Maritime Link Project versus Other Import, under base load conditions, is shown below in Figure 6-7. The benefit begins early in the period and continues to grow.

1 **Figure 6-7 Cumulative Benefit of Maritime Link Project versus Other Import**



2 The cumulative benefit per year of the Maritime Link Project versus Indigenous Wind,
3 under base load conditions, is shown below in Figure 6-8. Although the benefit begins
4 slightly later in the period, compared to the Other Import above, it is clearly beneficial in
5 the long-term.

1 **Figure 6-8 Cumulative Benefit of Maritime Link Project versus Indigenous Wind**



2 The Maritime Link Project is also the lowest long-term cost alternative under low load
3 conditions. Figure 6-9 provides a synopsis of the low load results. Under the Study
4 Period results, the Maritime Link Project is $532 million less than the Other Import
5 option. When compared to the Wind option, the Maritime Link Project costs $1 billion
6 less at low load.

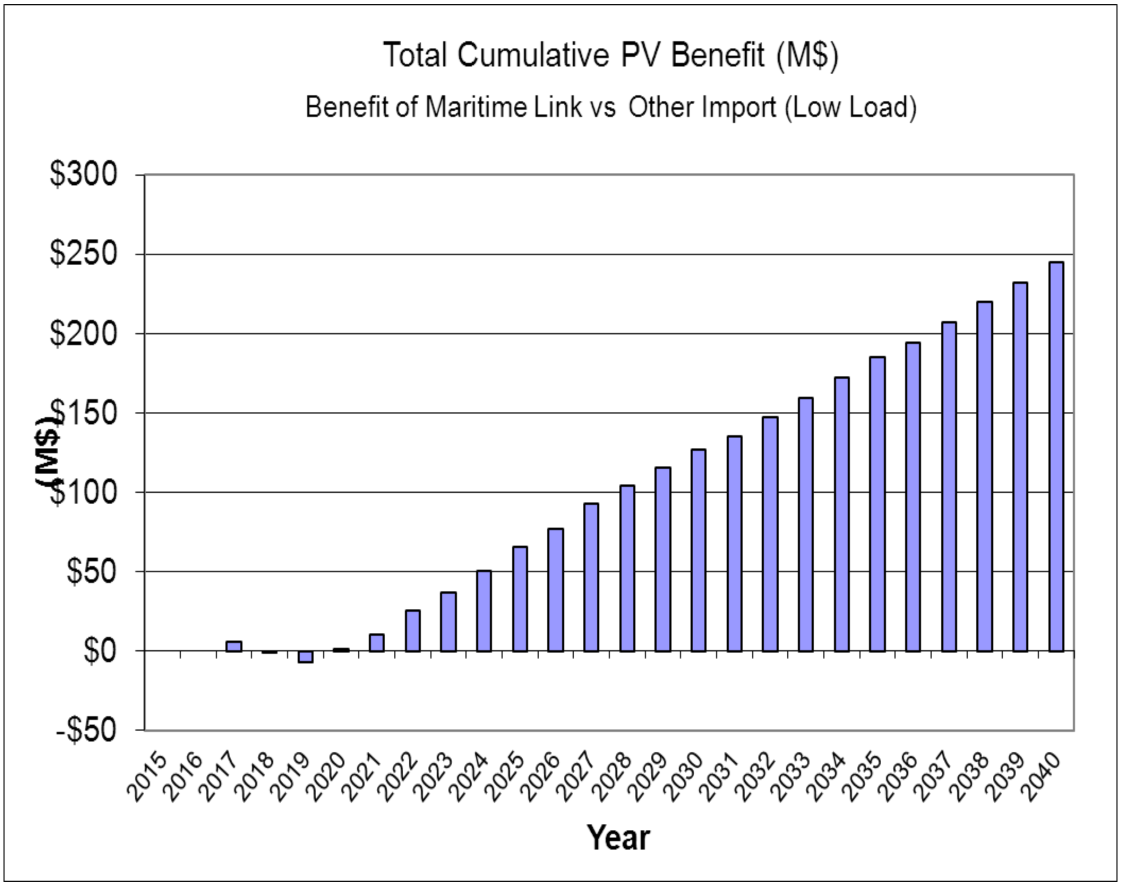
Figure 6-9 Comparison of Alternatives – Low Load

	Maritime Link	Other Import	Indigenous Wind*
Study Period ($M PV)	12, 221	12,753	13,244

** Wind costs in the Study Period reflect; model results of wind with no integration costs of $12,779 million plus integration costs of $465 million*.

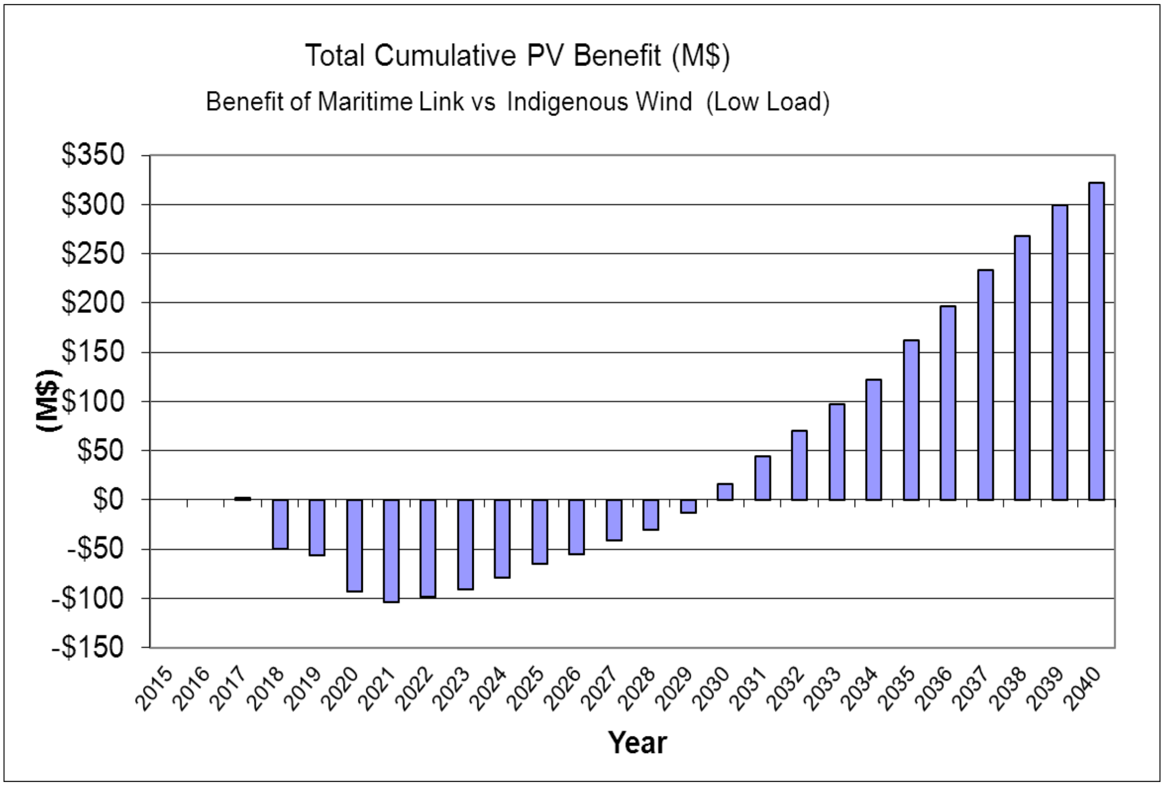
The cumulative benefit per year of the Maritime Link Project versus Other Import, under low load conditions, is shown below in Figure 6-10. Similar to the base load case, benefit begins early in the period and continues to grow.

Figure 6-10 Cumulative Benefit of Maritime Link Project versus Other Import



The cumulative benefit per year of the Maritime Link Project versus Indigenous Wind, under low load conditions, is shown below in Figure 6-11. Although the benefit begins later in the period, compared to base load conditions, it is clearly beneficial in the long-term.

Figure 6-11 Cumulative Benefit of Maritime Link Project versus Indigenous Wind



* *Does not include operating costs or natural gas infrastructure capital costs necessary to support the wind alternative.*

The Maritime Link Project is also the lowest long-term cost alternative with both low and high market prices for gas and power.

In high market price conditions, Figure 6-12 shows that under the Study Period results, the Maritime Link Project is $253 million less than the Other Import option. This is less than the $287 million benefit of the Maritime Link Project under base price assumptions, but is still a significant benefit.

When compared to the Indigenous Wind option, the Maritime Link Project costs $3.1 billion less. The benefit of the Maritime Link Project over Indigenous Wind increases by over $1 billion, under high market prices, because of the increased cost of fuel required to supplement the wind to provide adequate generation.

Figure 6-12 High Power and High Gas Prices Sensitivity

	Maritime Link Base Load	Other Import Base Load	Indigenous Wind Base Load
Study Period ($M PV)	18, 238	18,491	21,296

In low market price conditions, Figure 6-13 shows that under the Study Period results, the Maritime Link Project is $627 million less than the Other Import option. This is considerably more than the $287 million benefit of the Maritime Link Project, under base price assumptions.

When compared to the Wind option, the Maritime Link Project costs $1.3 billion less. Although this is less than the $2 billion cost difference, under base price assumptions, the Maritime Link Project is still the significantly lower-cost project even under low market price conditions.

Figure 6-13 Low Power and Low Gas Prices Sensitivity

	Maritime Link Base Load	Other Import Base Load	Indigenous Wind Base Load
Study Period ($M PV)	14,767	15,394	16,059

6.5 Conclusion

The Maritime Link Project is the lowest long-term cost alternative compared to the other options. The results of the analysis, summarized below in Figure 6-14, demonstrate that no other alternative provides a lower long-term cost option that meets the obligations under the *Electricity Act*, and the obligations governing the release of greenhouse gases and air pollutants under the *Environment Act*, the *Canadian Environmental Protection Act* (Canada) and any associated agreements.

Figure 6-14 Summary of Alternative Costs

Alternative	Baseload ($M NPV)	Additional Cost versus ML Alternative Baseload ($M NPV)	Low Load ($M NPV)	Additional Cost versus ML Alternative Low Load ($M NPV)
Maritime Link Project	16,209	n/a	12,221	n/a
Other Import	16,496	287	12,753	532
Indigenous Wind	18,182	1,973	13,244	1,023

The sensitivity analysis provides further assurance that if the load forecast is lower than anticipated today, the Maritime Link Project is still the lowest long-term cost option for customers. Similarly, if power and gas prices are higher or lower than predicted today, the Maritime Link Project is still the lowest cost option for customers.

NSPML anticipates that, by 2025, it will be possible to increase the amount of electricity that can remain within Nova Scotia, which is presently modelled at a 300 MW limit. By increasing the limitation assumption from 300 MW to 500 MW, and based on NSPML's expectation that additional Nalcor energy will be available by 2025, the benefit to customers of the Maritime Link Project increases by a further $495 million, after the cost of potential transmission upgrades.

7.0 MARITIME LINK PROJECT SCHEDULE

The Regulations require that an anticipated construction and in-service schedule for the Maritime Link, as contemplated under the Nalcor Transactions, be included in the Application.[51] That information is found in this section.

The Maritime Link Project began in early 2011, shortly after Emera and Nalcor announced agreement on the project. As a requirement to secure the FLG, Nalcor and NSPML have Sanctioned their respective projects. Commissioning of the Maritime Link facilities, and the first transmission of commercial power, is targeted for 2017.

The Project follows a structured approach to project management which is a recognized best practice for the review and approval of major capital projects in many industries. The approach uses project phases and Decision Gates at which completed work is reviewed before the project is allowed to progress to the next stage of development.

The activities of each Project phase provide the necessary deliverables and information to support management decision to proceed through to the next phase of work.

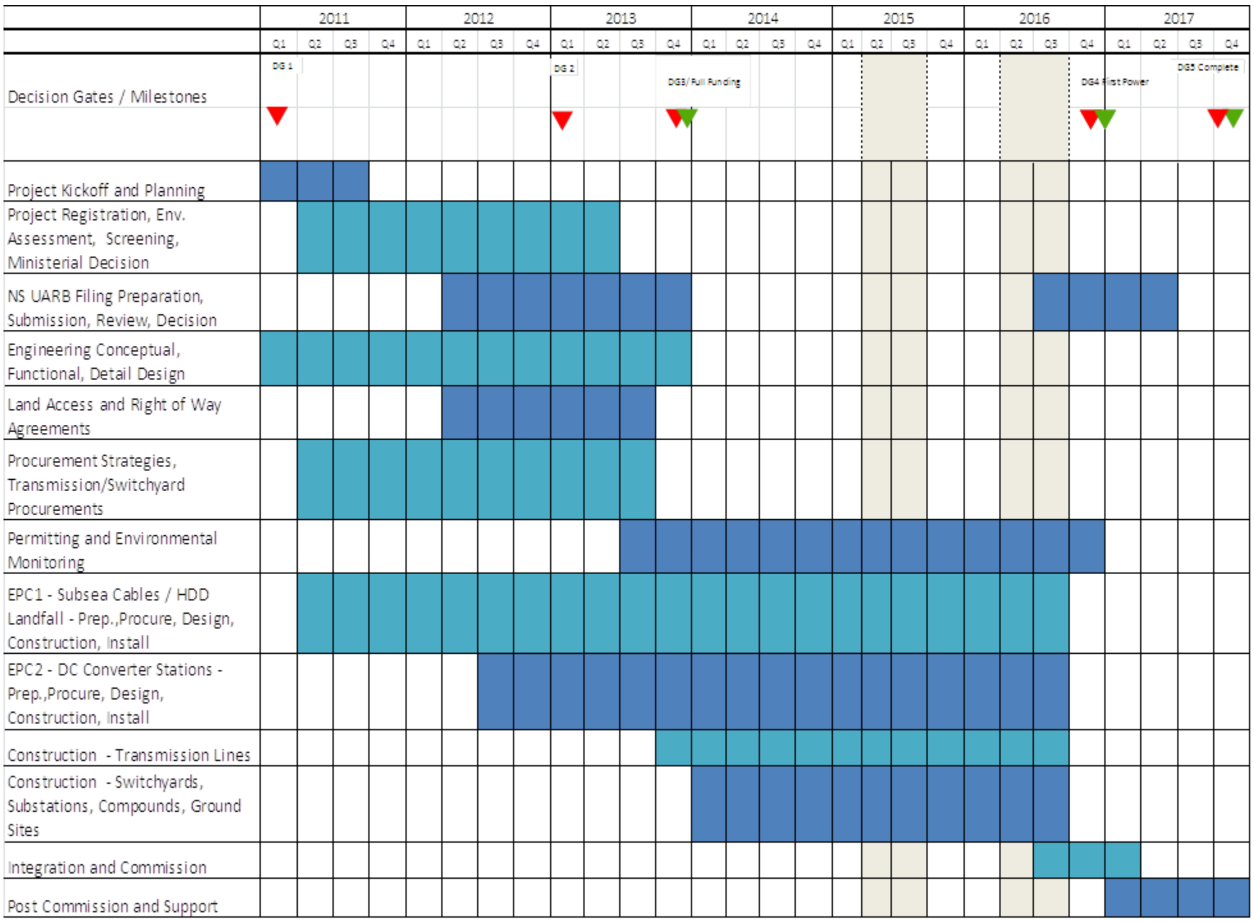
Key decision points are represented by Decision Gates that must be passed before the next phase of the project may begin. Each gate has the following attributes:

- It requires a variety of specific deliverables be produced and reviews to be conducted.
- It requires approval to pass through to the next phase.
- A decision to go on commits the Company to significant funding and allocation of resources.

[51] Paragraph 5(5)(g)

A high level project schedule is shown in Figure 7-1. Weather has been taken into account in the project plan. The second and third quarters of 2015 and 2016 are the marine weather installation windows.

Figure 7-1 Schedule



7.1 Concept Selection (Q4 2012)

The deliverables for this decision point, Decision Gate 2, include conceptual designs, a preliminary constructability plan, an operational philosophy plan, environmental strategies, Aboriginal and other Stakeholder outreach strategies, risk plans, financial estimates within an industry standard confidence level, and the funding strategies including the FLG. An Independent Project Review examined all these plans and deliverables, including a summary of findings and project readiness to proceed to the next phase of work. The project team presented a summary of the project status, including cost and schedule, and obtained approval to progress to the next stage. This stage includes Project Registration with the federal and provincial regulators, and the development and submission of the Environmental Assessment Report.[52] Information from the deliverables for this Decision Gate also provided input to this Nova Scotia Regulatory Application.

7.2 Construct (Q4 2013)

This is Decision Gate 3, the key decision point, identified in the Nalcor Transactions as the point which NSPML and Nalcor must pass through before construction of the Maritime Link begins. In advance of this decision point, the project will produce plans and deliverables encompassing detailed design of the Maritime Link, key procurement contracts for the marine cable supply and installation, the two AC/DC Converter Stations, and other significant long-lead items, the various construction services contracts, and the Land Right of Way agreements with public and private land owners. As with Concept Selection, the deliverables will be subjected to an Independent Project Review. Project estimates will progress to higher confidence levels. In addition, this phase requires the following external approvals:

- approval from the federal and provincial Ministers of Environment following the harmonized environmental review process, and

- approval from the Nova Scotia Utility and Review Board

Upon successful completion of these milestones and approvals from NSPML and Nalcor, the construction phase of the project begins.

[52] The Maritime Link Environmental Assessment can be found at http://www.gov.ns.ca/nse/ea/maritime-link.asp

7.3 Start-up and First Commercial Power (Q4 2016)

This decision point, Decision Gate 4, marks approval to begin final commissioning and energization of the Maritime Link. Project activities leading to this decision begin with the completion of the construction phase of the key contracts for the marine cable, the AC/DC Converter Stations, the AC substations at the interconnection points and the other project components. They also include commencement of preliminary commissioning activities for all project components.

Project managers will stage construction of the Maritime Link's components to ensure the efficient use of resources, in keeping with the project labor and benefit strategies. They will coordinate the work with NS Power and NL Hydro operational schedules. The project team will develop and implement a commissioning strategy to ensure testing of all components, updating of technical documentation, development of operational procedures, and training of operational staff. When all project components have been proven to be ready for operations, the Project will proceed to final dynamic commissioning and energization.

7.4 Project Close (Q4 2017)

The final decision is the official close of the Project in which a determination has been made that project closeout activity has been concluded. This is expected approximately twelve months after the startup of the Maritime Link.

During this period, the Project assets will be transitioned to the operational teams. All contracts developed for the project will be closed out, technical documentation updated, and all legal requirements and financial activities will be concluded

7.5 UARB Proceedings

This Application is made in accordance with Sections 4 and 5 of the Regulations, which provide for a UARB Decision no later than 180 days following filing of the Application.[53] The Application requests approval of the Maritime Link Project, as filed, as well as, *inter alia*, requesting approval of Maritime Link Project capital costs of $1.52 billion plus a variance with respect to these approved costs. The Regulations further require NSPML to file a project report no later than December 31, 2013, or an alternate date that may be ordered by the UARB.[54] Figure 7-1, above, indicates that all of these related steps are scheduled to be completed by the end of 2013.

The Nalcor Transactions require NSPML to make a DG3 capital cost determination for the Maritime Link Project no later than October 1, 2013.[55] This will allow NSPML and Nalcor to apply the 20 for 20 Principle and thereby establish the Project Cost for the rate base of the Maritime Link Project. NSPML will advise the UARB of the DG3 determination and the calculated capital cost for the Maritime Link Project as part of the project report that is required by Section 7(1) of the Regulations.

As part of the project report filing, NSPML will inform the UARB of the results of the 20 For 20 Principle calculation, and seek approval for any true-up payment or energy adjustment that result from the application of the 20 for 20 Principle. All aspects of the true-up arrangement, including necessary legal documentation and payments, if any, must be completed within 60 days.[56] Therefore, NSPML will file the project report as soon as possible following the DG3 determination, and will be seeking a timely approval from the UARB. The project report and approval request will describe the specific request by NSPML and necessary timelines.

[53] Section 5(4) of the Regulations
[54] Section 7(1) of the Regulations
[55] Appendix 2.15, Sanction Agreement, December 17, 2012, paragraph 3(d)
[56] Appendix 2.15, Sanction Agreement, December 17, 2012, paragraph 3(f)

This Application does not, nor will the project report filing, contain a request for approval of a revenue requirement or rate proposal for cost recovery. This Application does seek approval of several items that will inform that subsequent revenue requirement application, including *inter alia*, capital structure, return on equity and the treatment of AFUDC. The revenue requirement and rate application will be made in advance of commissioning of the Maritime Link Project, as required by Section 8 of the Regulations. Figure 7-1 demonstrates that the regulatory process for approval of the first NSPML revenue requirement is anticipated to occur in late 2016 or early 2017.

8.0 NOVA SCOTIA POWER PARTICIPATION

Although NSPML is the applicant in this submission, NS Power and its customers will perform a meaningful role in the Maritime Link Project. NS Power will receive and utilize, for the benefit of customers, the renewable energy and capacity contracted under the Energy and Capacity Agreement (ECA). NS Power will provide transmission scheduling and related services for the Maritime Link pursuant to the Maritime Link (Nalcor) Transmission Service Agreement (Nalcor TSA), the Maritime Link (Emera) Transmission Service Agreement (Emera TSA) and the Interconnection Operators Agreement (IOA). NS Power will also facilitate transmission of Nalcor Surplus Energy through Nova Scotia pursuant to the terms of the Nova Scotia Transmission Utilization Agreement (NSTUA). NS Power's obligations relating to the ECA, Nalcor TSA, Emera TSA, IOA and NSTUA are pursuant to the previously mentioned Agency and Service Agreement with NSPML, attached as Appendix 8.01. Pursuant to that agreement, NS Power will also take energy from NSPML put back to Bayside Power L. P. by Nalcor pursuant to the New Brunswick Transmission Utilization Agreement (NBTUA) or the MEPCO Transmission Rights Agreement (MEPCO TRA). This arrangement is outlined in both the Agency and Service Agreement which is attached as Appendix 8.01, and the Backstop Energy Agreement between NSPML and Bayside Power L. P. which is attached as Appendix 8.03.

8.1 Energy and Capacity Agreement

Through the ECA, NS Power's customers will benefit from a new source of reliable, dispatchable, clean, renewable energy at a stable price for 35 years. The Nova Scotia Block will provide eight to ten percent of Nova Scotia's total energy requirement in a way that can be planned and dispatched to serve customers in a manner not much different from NS Power's existing hydro systems. This energy source will further diversify the portfolio of energy options available to the Province and help NS Power provide long-term rate stability for customers.

As described in Sections 6.2.5, 6.2.6 and 6.3, NS Power provided assumptions and input into the Alternatives Analysis. NS Power has specialized knowledge regarding wind integration and indigenous wind options available in Nova Scotia. A white paper discussing the impacts and costs of the indigenous wind analysis conducted by NS Power is contained in Appendix 6.02. NS Power also supplied inputs to the Other Import scenario discussed in the alternatives analysis section. NS Power was engaging market participants to secure a long-term source of renewable energy prior to agreeing to the arrangement to import Muskrat Falls energy.

8.2 Transmission Related Obligations

The Maritime Link Project is also strategically important to NS Power customers, as it will create a second connection to the North American transmission grid through Newfoundland and Labrador. This new connection will help diversify Nova Scotia's portfolio of energy sources, thereby contributing to more stable electricity costs and robust energy access over the long-term.

As part of the exchange for 20 percent of the output from Muskrat Falls, Nalcor requires a transmission path through Nova Scotia and New Brunswick to allow Nalcor to deliver Nalcor Surplus Energy to the New England and New York markets.

8.2.1 NSTUA Obligations

The requirement for a path through Nova Scotia for the Nalcor Surplus Energy led to the Nova Scotia Transmission Utilization Agreement (NSTUA) between NSPML and Nalcor. NS Power participated in negotiations leading to the NSTUA, which is attached as Appendix 2.06.

As the system operator in Nova Scotia, NS Power is in the best position to fulfill the transmission obligations set out in the NSTUA, which include firm and contingent firm transmission service for the Nalcor Surplus Energy. Based on NSTUA requirements and expected quantities of Nalcor Surplus Energy, NS Power is expected to incur capital upgrade, maintenance and redispatch costs associated with providing a path for the Nalcor Surplus Energy from the interconnection point with the Maritime Link at Woodbine through to the Nova Scotia / New Brunswick border.

Pending more detailed study and evolution of transmission infrastructure, Figure 8-1 lists the capital projects associated with the transit of Nalcor Surplus Energy through Nova Scotia, and for which NS Power has indicated it will seek regulatory approval consistent with current rules for capital filings. NSPML is seeking UARB confirmation that these projects are currently necessary for the Nalcor Surplus Energy to have a path through the Province and the estimated costs are considered costs of the Nalcor Transactions as defined in Subsection 2 (iii) of the Regulations. They are provided to show the type and magnitude of the expenditures. These costs have been estimated using the methodology to calculate the Annual Capital Expenditure (ACE) Plan 5-year outlook. They may vary depending on start date, changes to material costs and other standard variables for capital projects.

Figure 8-1 Nova Scotia Power Network Upgrades[57]

NSPI Network Upgrades	Forecasted Investment					
	2013	2014	2015	2016	2017	Total
1 L-6513 Rebuild/Upgrade Line Terminals	1,610,000	8,168,000	322,000			10,100,000
2 Strait Crossing / Separate L-8004/L-7005	108,000	972,000	4,752,000	4,752,000	216,000	10,800,000
3 L-6511/L-6515/L-6552 Upgrades		1,060,000	9,540,000			10,600,000
	$1,718,000	**$10,200,000**	**$14,614,000**	**$4,752,000**	**$216,000**	**$31,500,000**

The cost to redispatch NS Power's fleet is also an estimate at this point and will depend on the amount and timing of the Nalcor Surplus Energy. Based on projections of Nalcor Surplus Energy, the estimated cost of redispatch is forecast to range from $6-8 million

[57] Projects 1 and 2 from this table were included in the 2013 ACE spend profile. The 3rd project was included in the 5-year outlook filed with ACE, because the spend is planned to begin in 2014 if necessary.

annually. By 2030, it is anticipated that constraints that currently limit the flow of energy from Cape Breton to the mainland will ease due to plant retirements, which should reduce the estimated cost of redispatch in the order of $4 million by that time**.**

The NSTUA requires Nalcor to pay the applicable NSTUA tariff rate for transmission of the Nalcor Surplus Energy, which tariff rate is a proxy for the NS Power OATT tariff rate, but billed on an as used basis. Based on projections of Nalcor Surplus Energy, it is expected that the transmission fees paid by Nalcor (which will be provided to NS Power pursuant to the NS Power-NSPML Agreement) during the term will offset the associated capital expenditures, redispatch costs, and anticipated system maintenance costs resulting from the Nalcor Surplus Energy flowing through Nova Scotia. Due to transmission constraints in the early years of the transactions, the costs of providing the transmission services may not initially be fully covered by the transmission revenues, though they are expected to cover the capital expenditures, redispatch costs, and anticipated system maintenance costs over the term of the agreement. In the event that the revenue from the Nalcor transmission fees does not fully cover capital expenditures, redispatch and system maintenance costs, NS Power will charge NSPML for those costs and NSPML will incorporate those costs into its assessment to NS Power. The NS Power-NSPML Agreement contemplates that this true-up will be calculated every 60 months.

8.2.2 Maritime Link JDA – Woodbine Upgrades

For the duration of the NSTUA, NS Power will maintain the Woodbine Upgrades and bill NSPML for the applicable costs and NSPML will incorporate these costs into its assessment to NS Power. Upon the Transfer Date as defined in the MLJDA, the ownership of the Maritime Link-related Woodbine Upgrades will be transferred from NSPML to NS Power.

8.2.3 Maritime Link – Transmission and Interconnection Agreements

The Agency and Service Agreement also contains standard utility obligations relating to NS Power managing the Maritime Link transmission and interconnection obligations. These obligations are contained in the Agency and Service Agreement, which incorporates the obligations contained in the Nalcor TSA, the Emera TSA and the Interconnection Operators Agreement. NS Power will charge NSPML for the related incremental costs, and NSPML will incorporate those costs into its assessment to NS Power.

8.2.4 NBTUA and MEPCO TRA

As contained in the NBTUA and MEPCO TRA, Emera has an obligation to provide a transmission path through New Brunswick for the Nalcor Surplus Energy. If Emera is unable to provide this path through New Brunswick in accordance with the terms of these agreements, Nalcor can require Emera to purchase the energy that Nalcor cannot get through the New Brunswick Transmission system. Due to the flow of this energy (via the Maritime Link), Nova Scotia is in the best position to provide an outlet for this potentially stranded energy.

As part of the Maritime Link Project and subject to system reliability considerations, NS Power will take such energy at a cost equivalent to the avoided cost of backing down the applicable amount of generation and/or turning back an alternate import supply. This obligation is contained in the Agency and Service Agreement between NSPML and NS Power, at Appendix 8.01. A correlating obligation will exist and is contained in the Backstop Energy Agreement between NSPML and its affiliate, Bayside Power LP, at Appendix 8.03. These arrangements are structured in this manner to be cost-neutral to NS Power's customers, and any other costs associated with these transmission obligations to Nalcor will rest with an affiliate of NSPML, and will not be passed on to the customers of NS Power either directly or indirectly.

Since this energy take requirement is cost neutral to NS Power the requirement is not included in the Alternatives Analysis.

Without the NBTUA and the MEPCO TRA the Maritime Link Project would not be possible. NSPML submits that approval of the NS Power backstop obligation is necessary to enable the Maritime Link Project and is therefore properly included as a component of this Application.

8.3 Affiliate Code

NS Power's Code of Conduct governing Affiliate Transactions (Affiliate Code) was created well before the advent of the Maritime Link Project, the *Maritime Link Act* and the Regulations thereunder. Section 3.1 of the Affiliate Code 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 other affiliate." Section 3 of the Regulations, however, provides that as an applicant, NSPML is deemed to be a public utility within the meaning of the *Public Utilities Act*. *The Maritime Link Act* and Regulations thus conflict with, but supersede the conflicting provisions in Section 3.1 of the Code, and Section 3.1 of the Code cannot pertain to the Nalcor Transactions and the Maritime Link Project.

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.

NSPML respectfully requests confirmation that to the extent that provisions of the Affiliate Code may conflict with the Nalcor Transactions, the Maritime Link Project and the related transactions within that Project, those provisions do not pertain to the Nalcor Transactions, the Maritime Link Project and the related transactions within that Project.

NS Power advises that in its dealings with the Nalcor Transactions, the Maritime Link Project and the related transactions within that Project, it has complied and will continue to comply with all applicable Affiliate Code provisions. The public review of the Maritime Link Project in this Proceeding under the *Maritime Link Act* and Regulations provides the transparency, analysis and documentation that the Affiliate Code would require of NS Power in respect other affiliate transactions.

9.0 CONCLUSION

The Maritime Link Project is the lowest long-term cost alternative that meets all legislative requirements described in Subsection 5 (1) of the *Maritime Link Cost Recovery Process Regulations*. In addition to costing less for Nova Scotia customers than any other alternative, the Maritime Link Project will provide new options for the long-term energy requirements of customers in Nova Scotia. No other potential solution can deliver these benefits.

The Maritime Link Project will give Nova Scotia access to reliable, renewable electricity at a predictable price from Phase 1 of Nalcor's Lower Churchill hydroelectric development in Labrador, will allow the province to meet new Federal regulatory requirements focused on GHG emission reductions and will assist in meeting Nova Scotia's *Renewable Electricity Standards.* Only the Maritime Link Project:

- increases rate predictability for electricity customers through long-term (35 year) fixed cost contract,
- provides greater long-term electricity security,
- offers a strategic transformational opportunity for enhanced access to competitive markets,
- offers access to large, new, renewable electricity supplies for a minimum of 50 years,
- offers specific quantities of renewable energy at a stable cost for 35 years,
- provides enhanced reliability,

- strengthens Nova Scotia's connection to the North American grid to prepare for and to take advantage of many future energy scenarios, and

- supports the development of additional intermittent renewable energy resources in Nova Scotia, such as wind and tidal.

Consistent with the underlying concept of the Nalcor Transactions, the capital costs of the Maritime Link Project will equal 20 percent of the capital costs of all projects contained in the LCP Phase 1 and the Maritime Link facilities. This amount and the approval requested by NSPML is estimated to be $1.52 billion with a variance of $60 million. This represents the lowest long-term cost alternative for Nova Scotians which would meet applicable environmental and legislative requirements.

The support of the Government of Canada via a loan guarantee is a unique and important feature of the Maritime Link Project that will directly benefit Nova Scotia customers and reduce the cost of the Maritime Link Project by more than $100 million on a net present value basis.

NSPML respectfully submits that this Application demonstrates that the Maritime Link Project meets the criteria established by the Regulations:

(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.

As such, NSPML respectfully requests Board approval of the Maritime Link Project and Nalcor Transactions, in accordance with the *Maritime Link Cost Recovery Process Regulations* made pursuant to the *Maritime Link Act* on the basis of this Application as filed.