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# Maritime Link – enabling high availability with a VSC HVDC transmission

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**SUMMARY**

The Maritime Link Project is part of a larger strategy to enable the transmission of clean, renewable and reliable electricity from Newfoundland and Labrador to Nova Scotia and beyond. The project involves the design, engineering, construction, commissioning and operation of a new 500 MW ±200 kV high-voltage direct current (HVDC), as well as a.c. system upgrades. The HVDC link comprises bipolar HVDC Light converter stations on Newfoundland and Nova Scotia, 140 km of overhead line (OHL) on Newfoundland, 50 km of OHL in Nova Scotia, as well as 170 km of subsea cable across the Cabot Strait and one OHL/cable transition station at each cable end. In addition, there is an earthing electrode and corresponding electrode line at both ends of the HVDC link.

The long-distance power transmission from Labrador over Newfoundland (NL) to Nova Scotia (NS) has significant implications for the existing a.c. systems. Typically, power systems intended for bulk power transmission over long distances utilize higher voltages (345 kV or higher) as well as meshed grid design with several parallel transmission paths to cope with potential contingencies such as line or generation outages. However, this is not the case for the NL an island system and NS a radial system, both with a limited backbone in their central part.

In order to allow for maximum utilization of the existing system when transmitting power from Labrador towards Nova Scotia several operational challenges must be overcome. With its unique feature for fast, independent control of active and reactive power, HVDC technology can enhance system operation both during normal conditions as well as during and after severe disturbances. This article describes additional control functions (in particular run-back schemes and frequency control) implemented in Maritime Link. Selected case studies illustrate the performance of these additional control functions.

**KEYWORDS**

security enhancement, emergency power control, special protection schemes, frequency control, automatic run-back, VSC HVDC, Maritime Link, Nova Scotia, Newfoundland.

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# 1 INTRODUCTION

The Maritime Link Project is part of a larger strategy to enable the transmission of clean, renewable and reliable electricity from Newfoundland and Labrador to Nova Scotia and beyond. The Maritime Link will allow Nova Scotia to import hydro electricity from the Muskrat Falls generating station in Labrador, which is being developed as part of the Lower Churchill Project.

The Maritime Link Project involves the design, engineering, construction, commissioning and operation of a new 500 MW ±200 kV high-voltage direct current (HVDC), as well as several a.c. system upgrades. The project is divided into three distinct geographical regions (Figure 1):

- Island of Newfoundland: 140 kilometres of HVDC transmission line along new and existing corridors between Bottom Brook and Cape Ray. The associated infrastructure includes two switchyards, one converter station, one overhead line (OHL) to cable transition compound, one onshore cable anchoring site, one grounding site, roughly 20 kilometres of grounding line, and about two kilometres of underground cable.
- Cabot Strait: Two subsea HVDC cables will span approximately 170 kilometres across the Cabot Strait from Cape Ray on the island of Newfoundland to an area west of the Point Aconi generating station in Cape Breton. This portion of the Project includes two landfall sites where the cables comes ashore in Nova Scotia and on the island of Newfoundland.
- Nova Scotia: 50 kilometres of new HVDC transmission line, parallel to an existing transmission corridor, between a point on the west side of the Point Aconi generating station and an existing substation at Woodbine. Associated infrastructure includes one converter station, one OHL/cable transition compound, one onshore cable anchoring site, one grounding site, roughly 40 kilometres of grounding line and about two sections of underground cable.

The project owner NSP Maritime Link Inc., a subsidiary of Emera Inc., has contracted ABB to supply the HVDC converter stations as well as the AC substations and the OHL/cable transition stations in both sides. The order was booked in the second quarter of 2014 and the project is scheduled for commissioning in 2017.

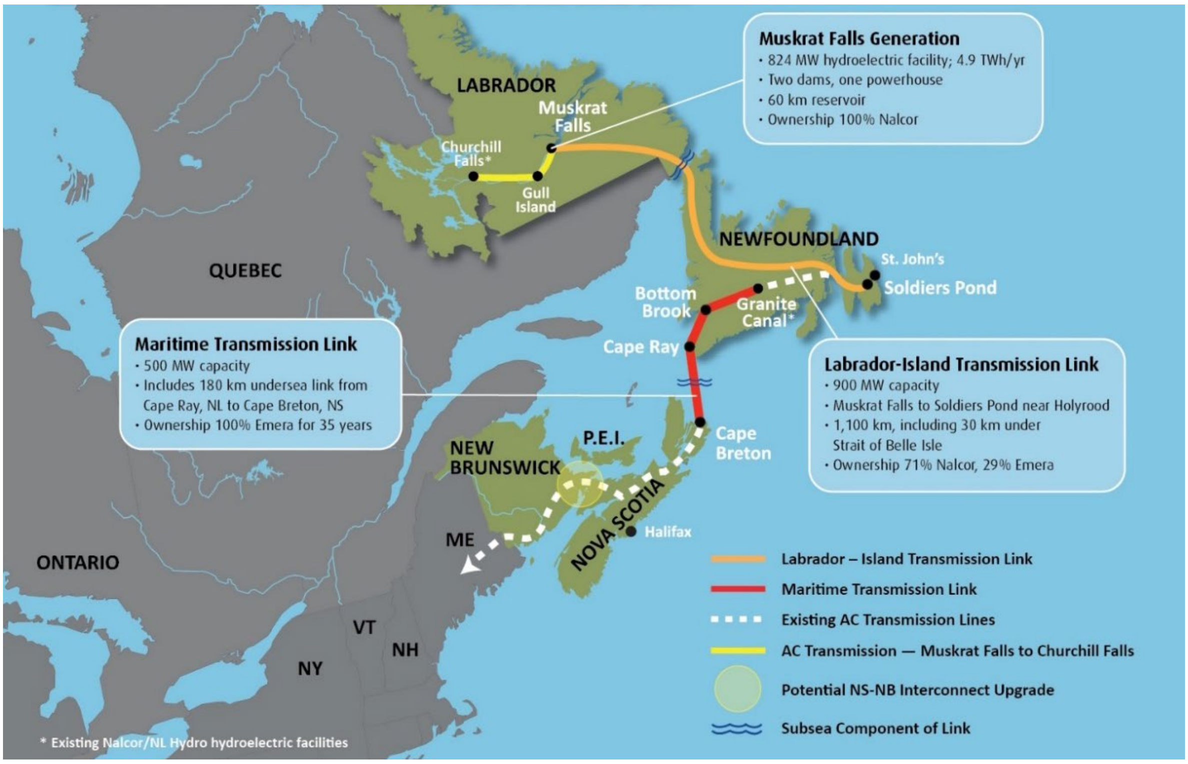


Figure 1 : Overview of Maritime Link and Labrador-Island Transmission Link.

The project creates benefits for Atlantic Canada and beyond:

- Moving to a cleaner source of energy helps Newfoundland and Labrador, and Nova Scotia reduce their use of fossil fuels and exposure to unpredictable oil and coal prices. By providing firm hydro back-up, the Maritime Link Project also enables further renewable energy development, such as wind, in both Newfoundland and Labrador, and Nova Scotia. This will break Nova Scotia from a century-old pattern of over dependence on a single, non-renewable fuel source – first oil, then coal.
- With the new interconnection between Newfoundland and Nova Scotia the Maritime Link creates a new Atlantic electricity loop, opening access to other energy import options available in a new market, as well as future renewable energy developments in Newfoundland and Labrador (Figure 1).

## 2 SPECIFIC NEEDS OF AC SYSTEM

As mentioned in section 1, the main objective of the transmission expansion in Atlantic Canada described here is to allow for power transfer from the Muskrat Falls generating station in Labrador towards Nova Scotia (Figure 1). For this purpose, the HVDC links between Labrador and Newfoundland (Labrador Island Link – LIL) as well as between Newfoundland and Nova Scotia (Maritime Link – ML) are currently under construction.

This new transmission task has significant implications for the existing AC systems of Newfoundland (NL) and Nova Scotia (NS). Typically, power systems intended for bulk power transmission over long distances utilize higher voltages (345 kV or higher) as well as meshed grid design with several parallel transmission paths to cope with potential contingencies such as line or generation outages. However, this is not the case for the NL and NS systems, as can be seen by the Single-Line-Diagrams shown in Appendix A.

The NL power system has been initially designed as an island system with a 230 kV sub-transmission line backbone in the center of the island and 138 kV distribution lines at the periphery. The island of Newfoundland will be interconnected to the a.c. power system of Labrador at substation Soldiers Pond in East Newfoundland via the Labrador Island bipolar line commutated HVDC Link. Similarly, the NS power system also features a sub-transmission backbone with an East-West orientation and a 345 kV connection to the New Brunswick power system from the central part of the island. 230kV distribution lines are used for the connection of the island periphery as well as in the East-West axis.

In order to allow for maximum utilization of the existing system when transmitting power from Labrador towards Nova Scotia following operational challenges must be overcome:

- Line outages in Central Newfoundland can potentially result in voltage instability if the power transit towards Nova Scotia is not reduced.
- Line outages in Central Nova Scotia can lead to transient instability and cascaded line tripping if the system loading remains constant. Currently, this operational risk is mitigated by Emergency Power Control Schemes ordering fast power reduction in generation stations located in the East of the NS system.

HVDC technology can effectively mitigate the aforementioned risks by applying advance control functions, see section 3.2 below.

# 3 TECHNICAL SOLUTION

## 3.1 System parameters

The HVDC transmission link Maritime Link, between Bottom Brook and Woodbine, is a voltage source converter connection that is designed to transmit power in either direction[1].

The choice for HVDC is motivated by several reasons:

- HVDC is the most efficient way to transmit electricity over long distances (lowest losses)
- It allows for long cable transmission, needed in this specific case for bridging the Cabot Strait
- The NL and NS systems are operated asynchronously
- HVDC allows for controlled power exchange and maximum utilization of the existing a.c. infrastructure

The rating of the bipolar is 2x250 MW at ±200 kV direct voltage, with the capability to operate continuously in monopolar mode. When operating with reduced voltage e.g. due to operational constraints the link is still capable of transmitting 350 MW.

In addition to active power, each of the converters at each station has the capability to provide up to ±125 MVAr reactive power independently of the operation mode of the converter in the other pole. The reactive power capability is even higher (up to ± 50 % of the converter's MVA rating) when the converters run as STATCOM[2].

Table 1 : Main system parameters

| | |
|---|---|
| Power rating: | 500 MW |
| No. of poles: | 2 |
| AC voltage: | Newfoundland: 230 kV<br>Nova Scotia: 345 kV |
| DC voltage: | ±200 kV |
| Length of DC overhead line: | 187 km |
| Length of DC submarine cable: | 170 km |
| Length of DC land cable: | 1 km x2 |

The total transmission distance is approx. 360 km including both overhead and cable section. The link is designed to transfer power between the Newfoundland and Nova Scotia power grids. By its bipolar design, the Maritime Link VSC HVDC solution provides high availability and fully redundant infrastructure for intra-region power distribution. The system SLD is shown in Figure 2

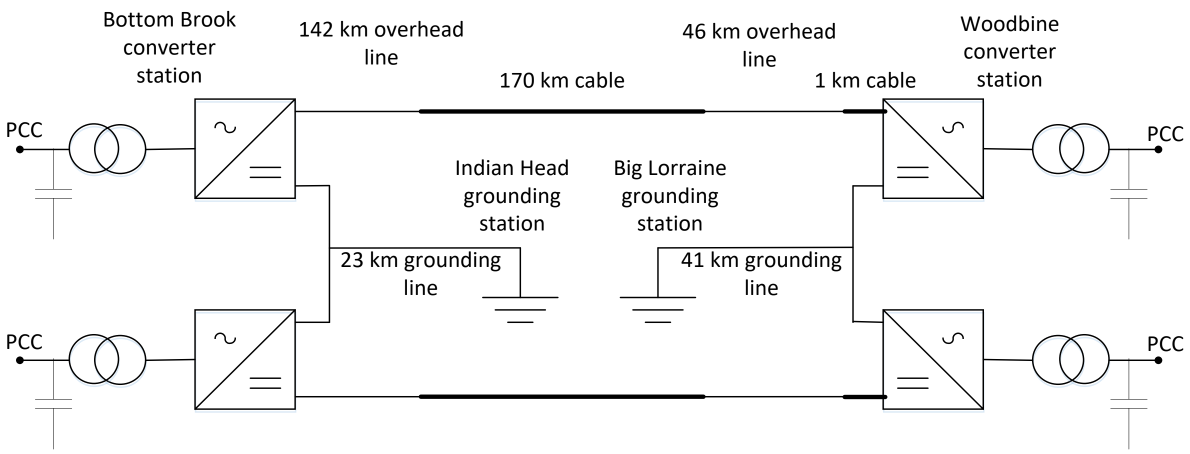


Figure 2. HVDC system overview.

[1] The main power direction is from Bottom Brook on Newfoundland to Woodbine in Nova Scotia.
[2] STAtic reactive power COMpensator.

## 3.2 Control of active power

### 3.2.1 General

Each HVDC Light converter is able to control active and reactive power independently by simultaneously regulating the amplitude and phase angle of the fundamental component of the converter output voltage [1]. The converter in active power control mode controls its a.c. side power to a reference value, provided that the d.c. voltage is within acceptable limits. Only converters in active power control mode can control their active power and the converters in d.c. voltage control mode has to take the balance. The power order is typically given directly as a dispatched power order, and may also be superimposed by a dynamic power order for various types of additional control functions. HVDC Light converters also allow for islanded network operation: in this operating mode the frequency is defined by the frequency reference, and the active power depends solely on the power exchange needed by the connected a.c. system for staying at that frequency. In this paper, the discussion is limited to additional control functions described in the following sections.

### 3.2.2 Emergency power control (also referred to as Special Protection Schemes)

The fast control of active and reactive power can enhance grid dynamic performance following disturbances. For example, if a severe contingency threatens the systems transient stability, fast active power run-back, run-up or an instant power reversal can be used to maintain synchronized grid operation. Contingencies such as loss of a.c. transmission, generation or load may require an automatic reduction in the d.c. power transfer including possible power reversal, i.e. runbacks. Contingencies involving loss of system capacity or spinning reserve in the a.c. network may require that the d.c. power transfer instead is rapidly increased in order to improve the performance of the a.c. system, i.e. run-ups.

The runback and run-up can either be absolute, i.e. the power is ramped to a pre-defined level, or relative, i.e. the reduction/increase is a pre-defined step size; either a constant step size or percentage of the actual transmitted power. Emergency power actions may be initiated by external inputs or signals derived within the control system.

### 3.2.3 Frequency control

HVDC systems can enhance stability problems by drawing energy from the remote system, and thereby control the local network frequency. Because of its ability to change the operating point instantaneously, HVDC can feed (or reduce) active power into a disturbed system and obtain a much faster frequency control than a generator. Coordination with other control functions, such as emergency power control and islanded network control, is performed automatically in the control system.

During frequency control the power order of the converter in active power control mode will have a contribution from a frequency regulator for keeping the frequency of the a.c. network within the design limits. Frequency control is only possible with a certain amount of inertia in the a.c. network for which frequency should be controlled. With the telecommunication working, also the frequency of the network connected to the converter in d.c. voltage control mode may be controlled. The frequency control can manually be disabled and enabled by an operator.

## 4 DESIGN STUDIES

Additional control function for security and stability enhancement of the surrounding grid such as those described in section 3.2 above have long been employed in HVDC systems [3]. For example, the Pacific Intertie HVDC link features run-back schemes triggered manually or automatically. Also, the majority of the HVDC systems in Scandinavia and around the Baltic Sea are equipped with emergency power control and frequency control schemes. With higher utilization of the a.c. grids, such schemes are increasingly required.

Over the years, ABB has collected significant experience with designing supplementary controllers for security and stability enhancement. In order for the control to be effective, it needs to be adapted to the specific needs of the a.c. system. Parameters such as system inertia, voltage control and line loadings around the connection point of HVDC converters during high, normal and low load conditions as well as for various design contingencies are important input data for the control design. For this reason, close collaboration between the system operator and the HVDC supplier is required.

Starting point for the control design is the definition of system loading and contingency scenarios as described in section 4.1 below. Based on this information, system models are set up both for off-line design studies as well as for on-line performance verification tests (hardware-in-the-loop tests with real time simulations). Based on the design network configuration and requirements provided by Emera, ABB has designed the emergency power and frequency controller as described in sections 4.2 and 4.3 below. Factory systems tests, jointly conducted with Emera, proved the intended control performance.

### 4.1 Network modelling

When specifying a transmission expansion project, the system operator analyses the topology of the grid in order to define the design operating conditions for the new infrastructure in an early phase. Steady-state load flow, short-circuit and reliability studies are part of this process; so are also transient stability studies. This investigation by the system operator is not specific only to an HVDC project, but in this case, it is even more important due to the fast dynamics of HVDC systems.

In the design phase of an HVDC system, the supplier uses detailed models of the surrounding grid for control design and verification. The process for exchanging network data between the system operator and the HVDC supplier is therefore important. After receiving network data, the supplier performs studies with limited scope to ensure correct load flow, short circuit levels and dynamic performance results. Parts of the network that do not significantly contribute to the dynamic response of the a.c. grid are typically reduced; this step is necessary for simulations with very small time steps e.g. in the dynamic performance studies or for real-time simulations. Close interaction with the system operator along the complete process of data validation, network reduction and creation of network equivalents ensures the quality of the used models.

### 4.2 Emergency power control design

The Emergency Power Controller is an additional high level control that aims at setting runback power levels (limiting/reducing converter power) for certain well defined and easily identified severe network contingencies (several lines/load/areas and/or generator trips). Such severe network contingencies may threaten continued network operation and reduces the ability to transfer power through the HVDC link. In rare cases, increase of converter power (run-up) may be applicable.
The EPC is an open loop control system, which reacts on certain criteria in the disturbed system. Input signals to EPC are given by the operator. In case of the EPC action the frequency controller (section 4.3) is disabled.

For the EPC design studies, relevant cases have been identified by load flow and transient stability studies. The causes are typically extensive loss of generation, extensive loss of load, or loss of critical lines or other elements. During such severe disturbances in the a.c. networks, the HVDC transmission can assist to distribute the power unbalance between the systems by firm and fast change of the HVDC power transfer (runback) within the limits of the transmission capacity. When severe system conditions occur, i.e., the network comes in a state of emergency that requires intervention of runback or run-up measures, clear indications are needed to select proper level of action. The operator's SCADA system automatically provides the digital indications as input.

The controller design principle is to select easily available and robust signals of nearby network conditions/events to initiate the EPC action. The EPC is an open-loop control system, which acts on logical signals from the disturbed system, and has no feedback from the undisturbed system[3]. Thus, a number of pre-selected HVDC transmission power levels (runback /run up levels) are introduced, which allow for continuation of system operation after a severe disturbance. The system for each converter station consists of two sections. One section is the logic circuit which interprets information from the network about occurred events and triggers the other section (EPC) to convert these event signals into HVDC converter power order runback/run up levels.

The signals from the faulted network are made available at HVDC converter stations by the system operator for initiating EPC action. However for those events which result to voltage collapse at Bottom Brook converter, an automatic runback is implemented. This runback will trig when the converter power is exceeding the steady state PQ limit for a predefined time. The power is then reduced to the predefined level. The settings are adjusted during this study so that ML reduces the power to half 150 ms after an overload detection. In the design studies, step change in power has been used for EPC. A telecommunication delay of 25 ms is considered for the triggering signal to reach the converter station from the faulted part of the network.

The power transfer through the HVDC link is reduced (runback) in order to stabilize the system. For the NS system an additional requirement has been to use the run-back scheme of the Maritime Link to substitute existing Special Protection Schemes currently implemented at generating stations. Due to this requirement, very fast ramping of the transmitted power is needed (up to 5,000 MW/s).

### 4.3 Frequency control design

The purpose of a Frequency Control Study is to develop additional controls with respect to frequency, to enhance operation of the interconnected systems. A frequency controller has been designed to control the flow of power through the Maritime Link so as to minimize the frequency deviation and thus assist the disturbed region in maintaining the system operating frequency around the targeted value. The design of the frequency controller is based on the frequency deviation in certain extreme cases. When the frequency of the faulty (primarily disturbed) system exceeds any of the dead band limits, it will activate a power order change ($\Delta$Pdc) to the converters to reduce the frequency deviation.

The HVDC link will adjust the power to control frequency in the faulty a.c. grid. As a result, the frequency of the healthy system will also be changed. If its frequency also exceeds any of the dead band limits, it will activate a power order to reduce (counteract) the initial change ($\Delta$Pdc) to the converters in order to reduce its frequency deviation. The frequency controller uses information about the frequency in both grids. Consequently, the operation of the frequency controller requires communication between the rectifier and the inverter of the HVDC link.

[3] Upon activation of an automatic runback in the NS system, the order has to be acknowledged by the HVDC control system. Should this confirmation signal not be provided within a specified time interval, the a.c. grid protection system trips the main breakers of the Woodbine converter and disconnects it from the NS system. This can be seen as an extreme back-up EPC action in the a.c. protection system with feedback from the HVDC control system.

Results are found to be satisfactory. The conclusion of the frequency control study is that the HVDC converter frequency controller in certain extreme cases will assist to balance the systems in a stable manner and to prevent possible load shedding, under certain generation load unbalanced disturbances occurring in the systems.

## 5 CASE STUDIES

In this section results from dynamic performance tests are provided for two selected cases. The intention is to illustrate how the additional control functions described above can assist to keep the NL and NS power systems in stable operation following severe contingencies.

### 5.1 Case 1: Voltage stability enhancement in Newfoundland

This study case describes a severe contingency in Newfoundland with a line-to-ground fault on the 230 kV transmission line between Upper Salmon and Granite Canal followed by an unsuccessful reclose attempt and eventually a permanent line trip. The NL system is lightly loaded (summer load conditions) with both Labrador Island Link and Maritime Link transmitting their nominal power towards South. The faulty line as well as the connection point for the ML converter are shown in Figure 5.

Following the line trip, the remaining East-West lines in Central Newfoundland must pick up the load, thus increasing the total reactive power demand of the system. In the Newfoundland system, the control system is designed to engage an EPC action, effectively cutting power transmission in half, if the a.c. grid consumes more than 250MVAr for more than 150 ms while a.c. voltage is above 0.8 pu. This is meant to alleviate possible overloading of a.c. transmission lines in the mid-section of the NL grid following faults and subsequent line trips. The Maritime Link controller responds automatically to the excessive reactive demand and execute a power runback reducing (bipole) power transmission to 250 MW, thereby alleviating the overload, as described in section 4.2 above.

The system behavior can be seen in Figure 3 below. Following signals are plotted: active and reactive power[4] of the ML converter at Bottom Brook, voltages of selected 230 kV nodes in the NL system, as well as active and reactive power flows over selected lines in the NL system. Following the fault initiation at 1 s and the unsuccessful line re-closure at 1.7 s, the voltage begins to deteriorate as can be seen e.g. for the voltage at node Buchans. The ML converter at Bottom Brook tries to support the voltage by supplying additional reactive power (up to 270 MVAr), until the conditions for EPC activations are fulfilled. Following EPC activation, active power transmission through the HVDC link is quickly reduced to 250 MW within less than 0.5 s. By this EPC action, voltage in the NL system recovers.

[4] In the figures in section 5, power is shown for each pole of the ML HVDC system.

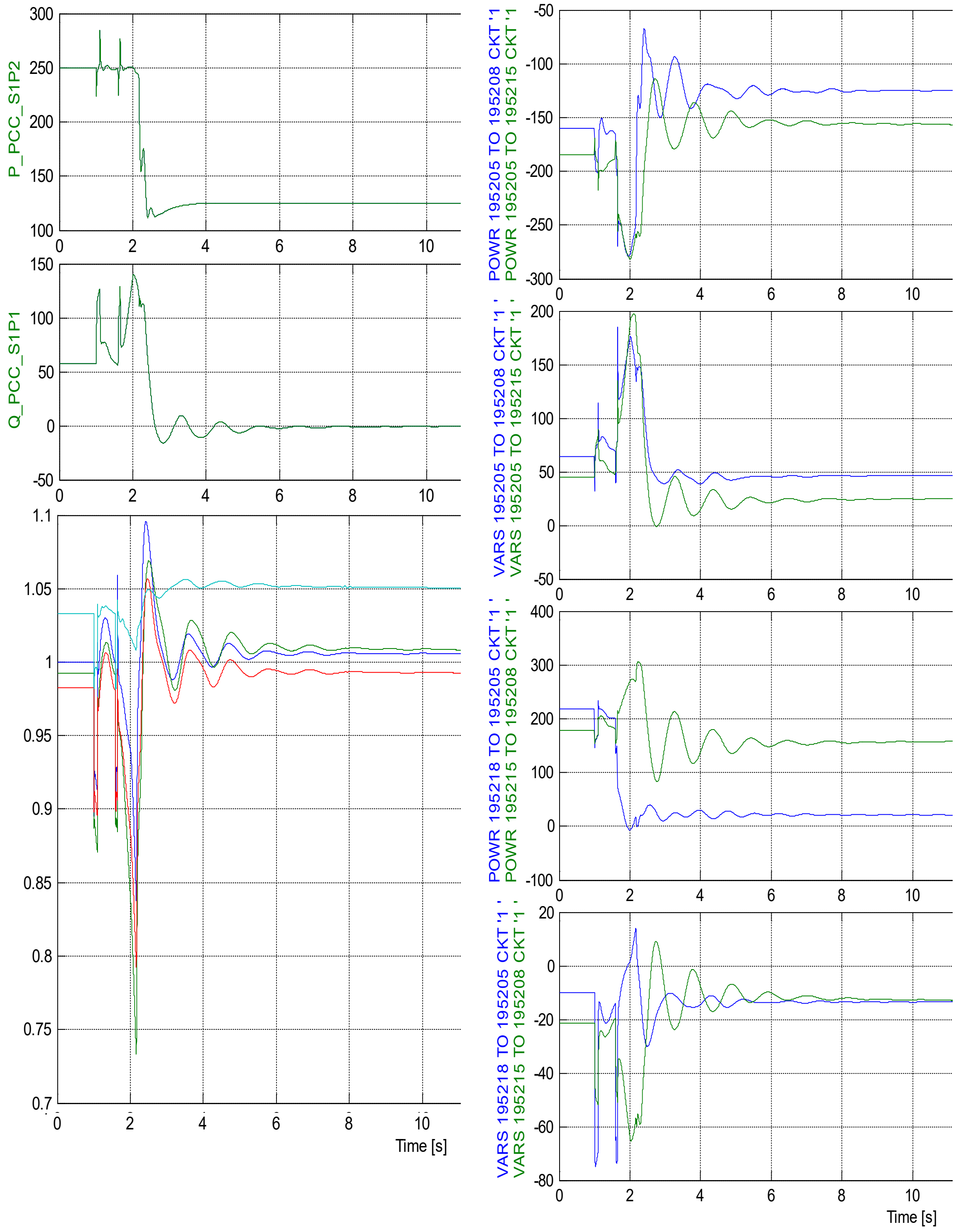


Figure 3 : Simulation results for case 1 .
Left: Active active (upper, in MW) and reactive (middle, in MVAr) power of Maritime Link converter at Bottom Brook (pole power)
Left lower plot: Node voltage in pu at Bottom Brook (blue), Buchans (green), Massey Drive (red) and Solder's Pond (cyan).
Right: active (upper, in MW) and reactive (second upper, in MVAr) power along lines Bottom Brook – Massey Drive (blue) and Bottom Brook – Buchans (green)
Right: active (second lower, in MW) and reactive (lower, in MVAr) power along lines Bottom Brook – Granite Canal (blue) and Massey Drive – Buchans (green)

### 5.2 Case 2: Avoiding cascaded line outages during faults in Nova Scotia

This study case describes a severe contingency in Nova Scotia with three-phase fault at node Hopewell followed by a permanent trip of line Hopewell-Onslow. The system loading conditions are the same as for case 1 above (summer load conditions with both Labrador Island Link and Maritime Link transmitting their nominal power towards South). The faulty line as well as the connection point for the ML converter are shown in Figure 6.

The NS system has constrained East-West corridors and a Special Protection System (SPS) is utilized to quickly reduce the generation of power under fault conditions. A fast response is critical to avoid instability and cascaded line tripping. To avoid interrupting the thermal units, the SPS initiates fast power run-back on the Maritime Link by enabling MW blocks for runback in a safe and predefined manner according to the scheduled power flow on the inter-tie.

The system behavior can be seen in Figure 4 below. Following signals are plotted: a.c. voltage, active and reactive power of the ML converter at Woodbine (left side), as well as active and reactive power flows over selected lines in the NS system (right).

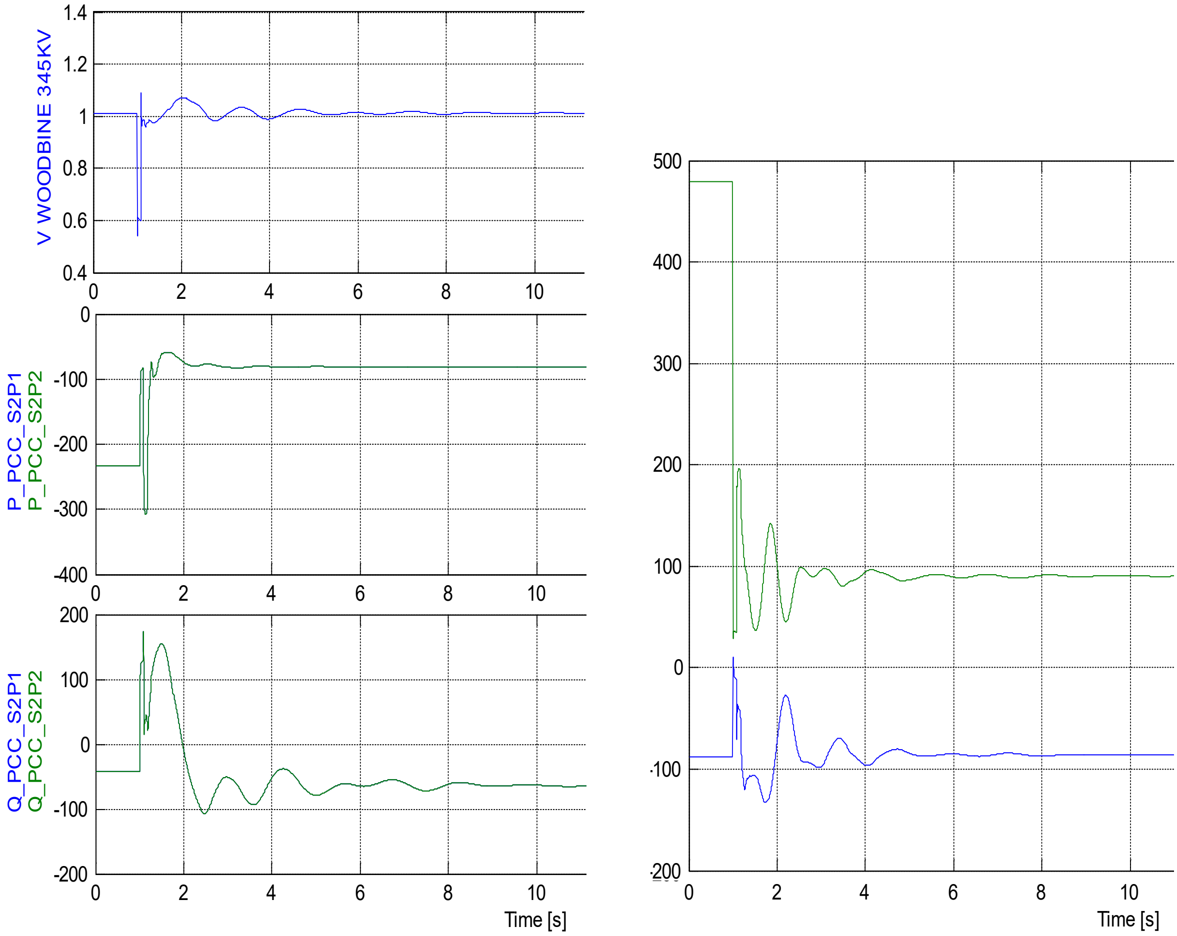


Figure 4 : Simulation results for case 2 .
Left upper plot : Node voltage in pu at Woodbine
Left: Active active (middle, in MW) and reactive (lower, in MVAr) power of Maritime Link converter at Woodbine (pole power)
Right: active power (in MW) along lines Woodbine – Lingan (blue) and Woodbine – Hopewell (green)

The fault occurs at 1 s. Due to the voltage dip, active power supply be ML as well as active power flow over the line Woodbine-Hopewell reduces. Once the fault is cleared after 150 ms, active power from the ML converter increases back to the pre-fault level again, compare second left plot. At the same time the HVDC converter receives the activation signal from the SPS PLC indicating that a critical line has been tripped (in this case the line between Hopewell and Onslow) which triggers the EPC action. Upon that, active power of the ML is rapidly reduced by 330 MW to avoid overloading of the remaining lines as well as transient power oscillations. A new stable operating point is reached within a few seconds without the need to ramp-down conventional power generation in East Nova Scotia.

The reduction in power flow over ML due to the run-back results in an excess of power and therefore in a frequency increase up to 60.85 Hz in the NL system. Should the EPC scheme not have been activated, this would cause the frequency controller to increase the power flow over ML again in an attempt to counteract the frequency increase in NL. Proper coordination and interlocking between control modes ensures that a controller with lower priority (in this case the frequency controller) does not compromise the performance of a controller with higher priority (in this case the EPC controller).

## 6 CONCLUSIONS

The Maritime Link Project is part of a larger strategy to enable the transmission of clean, renewable and reliable electricity from Newfoundland and Labrador to Nova Scotia and beyond. The use of existing a.c. infrastructure – enhanced by HVDC links – for this long-distance transmission is a challenging task. With its unique feature for fast, independent control of active and reactive power, the employed HVDC Light technology enhances system operation both during normal conditions as well as during and after severe disturbances.

Studies performed during detailed design demonstrated that the loading of the a.c. grids needs to be limited in order to survive severe contingencies if the transmitted power over the Maritime Link is be kept constant. However, in order to allow for maximum system utilization, additional HVDC control functions such as run-back schemes and frequency control have been developed and successfully tested. Although such schemes have been implemented in HVDC systems previously, some new concepts have been developed in the Maritime Link, in particular the automatic activation of run-backs to avoid voltage collapse or the use of very high ramp rates for run-backs to avoid transient instability and cascaded line trips. The presented case studies illustrate the performance of these additional control functions.

For the development of tailor-made additional control function, a close cooperation between the system operator and the HVDC supplier is of outmost importance. For Maritime Link, ABB could provide benefit from a long-term record of control design and implementation, while Emera could bring in the in-depth knowledge of its system and related needs.

More than before, transmission expansion is driven by the increased need for integration of remote renewable energy sources on the one hand and for more integrated energy markets on the other hand. Depending on the geography and network topology, the combined use of existing a.c. infrastructure, extended by HVDC links for controlled, long-distance transmission may be an interesting alternative. Additional control functions like the one implemented in Maritime Link can offer significant value in such schemes by relaxing operational constraints.

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## APPENDIX A

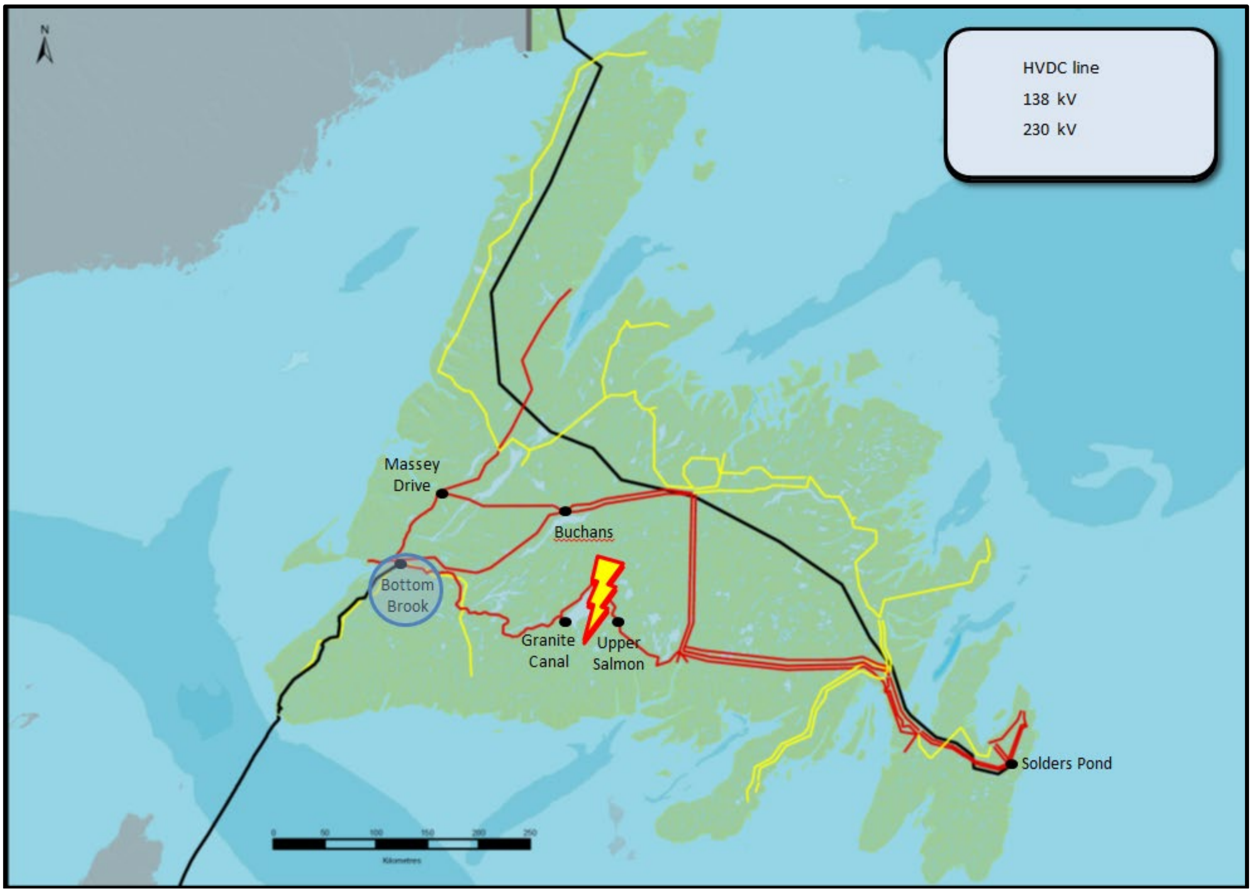


Figure 5 : System map for Newfoundland.

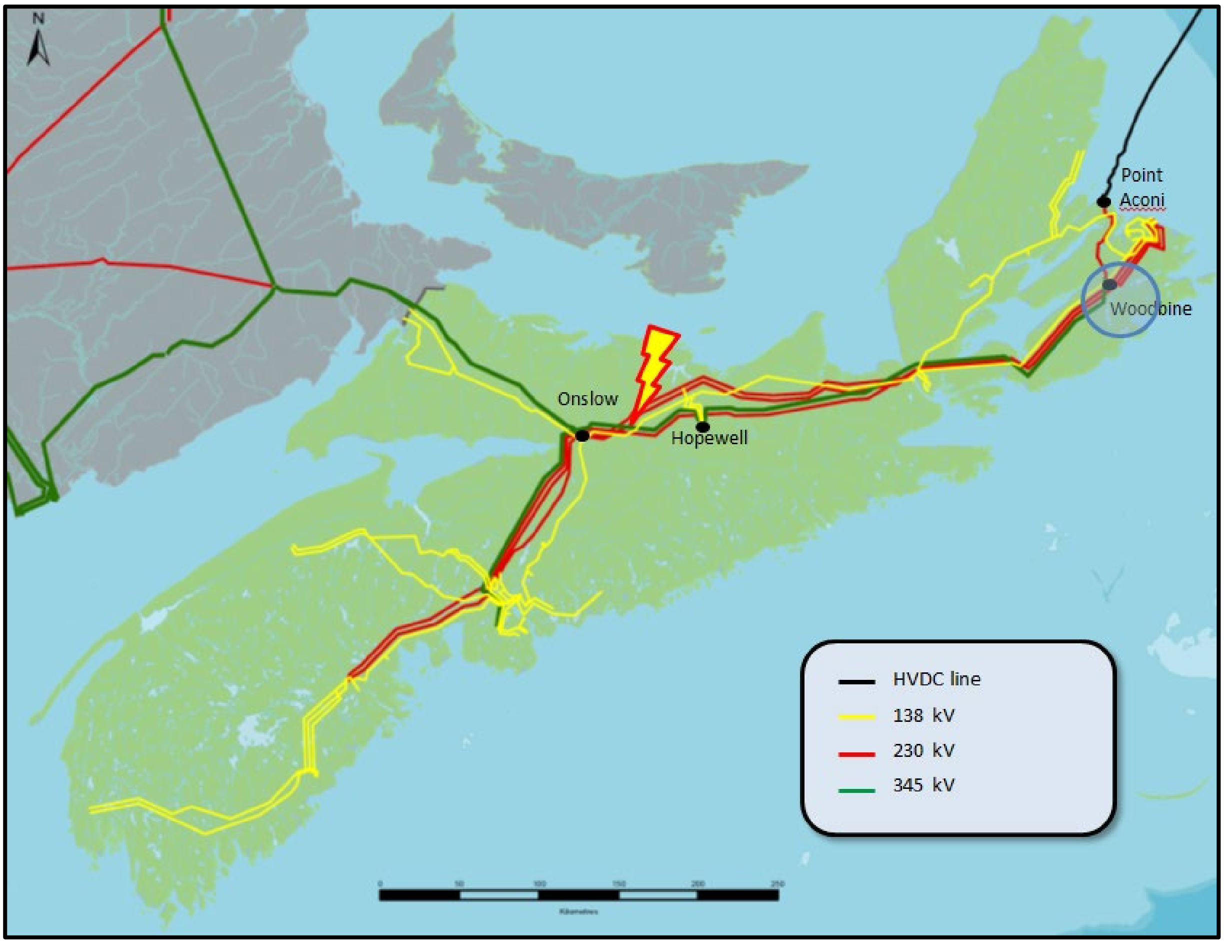


Figure 6 System map for Nova Scotia.