4 Technical Review – Infeed Option

The Infeed Option is largely a hydroelectric generation plan (923 MW by year 2067), with the addition of 520 MW of thermal generation. The following table describes the timing, size, and type of new generation sources added to the island with the Infeed Option.

Table 8: Infeed Option Generation Plan

Year	Infeed Option	Additional Capacity (MW)	Type
2010			
2011			
2012			
2013			
2014	50 MW CT	50	Thermal
2015			
2016			
2017	Holyrood U1 Synchronous Condenser 900 MW Labrador-Island Link HVdc System	900	Hydroelectric
2018			
2019			
2020			
2021	Holyrood Decommissioning begins		
2022			
2023			
2024			
2025			
2026			
2027			
2028			
2029	Holyrood Decommissioning complete		
2030			
2031			
2032			
2033			
2034			
2035			
2036	23 MW Portland Creek	23	Hydroelectric
2037	170 MW CCCT (Greenfield)	170	Thermal
2038			
2039			
2040			
2041			
2042			
2043			
2044			
2045			
2046	50 MW CT (Greenfield)	50	Thermal
2047			
2048			
2049			
2050	50 MW CT (Greenfield)	50	Thermal
2051			
2052			
2053			
2054	50 MW CT (Greenfield)	50	Thermal
2055			

Year	Infeed Option	Additional Capacity	Type
2056			
2057			
2058	50 MW CT (Greenfield)	50	Thermal
2059			
2060			
2061			
2062			
2063	50 MW CT (Greenfield)	50	Thermal
2064			
2065			
2066	50 MW CT (Greenfield)	50	Thermal
2067			

4.1 Muskrat Falls Generating Station

The Muskrat Falls Generating Station feasibility studies, cost estimates, and schedule were examined by MHI's technical experts to determine if they were completed using practices and procedures normally followed in the development of hydroelectric sites. The arrangements proposed for Muskrat Falls Generating Station were also reviewed to determine whether there were any conditions that might preclude successful development of the scheme. The project has evolved from early conceptual studies in the 1960's to the present detailed arrangement. Key documents include the Feasibility Study[38] and its associated reference documents, which were completed in 1999. The arrangement of the project was subsequently updated in a series of studies, completed in 2010, that adapted the layout and design to suit changes in circumstances and the final development sequence for the Lower Churchill River.

MHI's review involved an examination of the key documents to assess the methodology adopted and information used to develop the final project arrangement. Clarifications were obtained from Nalcor during meetings held to discuss key aspects of the development. The review was not intended to be exhaustive but to be sufficient to ensure that the decisions and recommendations reached for development of the project were well founded on factual and appropriate information.

The proposed layout and design of the project appear to be well defined and consistent with good industry practices. Available studies have identified technical risks and appropriate risk mitigation strategies. Findings are as follows:

- Topographic and geotechnical conditions have been identified and provide a sound basis for construction.

[38] Exhibit 19, SNC-Agra, "Muskrat Falls Hydroelectric Development – Final Feasibility Study Volume 1", January 1999

- The installed capacity was selected based on the anticipated system cost for power and energy to optimize the project development.
- The general arrangement of the permanent works is a reasonable proposal for the optimum development in terms of cost and construction duration.
- Based on the information provided, the design and proposed construction sequence of the Muskrat Falls Generating Station are consistent with good engineering and construction practices, and should not pose unusual risks for construction or operation of the facilities.
- The powerhouse arrangement does not pose unusual risks or abnormal features. The selection of Kaplan units is a conventional choice for the head and discharge conditions. Several well qualified manufacturers are available to supply this equipment, which should allow for competitive pricing for equipment procurement.
- The transmission line and converter stations proposed are consistent with the requirements of Muskrat Falls Generating Station. There is no reason to expect any unusual risks or difficulties with the arrangement when the final design is prepared.
- Work has been scheduled for the construction of the facilities using conventional and proven methods. There is no reason to believe that the construction of the facilities proposed would result in unusual risks for cost escalation or time extensions.

A detailed project control schedule and cost estimate has been prepared for the Muskrat Falls development. The project control schedule was developed with an assumed contract strategy, taking into account the capability of contractors, weather conditions, access, and other constraints. The project control schedule is believed to be close to the optimum duration and to be a realistic basis for planning of the works.

Based on the information available, the overall construction duration is believed to be reasonable. The project schedule indicates that the Muskrat Falls development can be completed within a total of about 62 months[39], assuming release for construction and commencement of contract awards in January of year one.

The Nalcor DG2 Capital Cost Estimate for the Muskrat Falls development was prepared as a "bottom up" estimate that considered construction productivity and schedules along with the cost of materials, equipment, and labour required for construction. An overall review of the cost estimate was performed by MHI but a detailed review of the estimating procedures was not.

The cost estimate for the Muskrat Falls development has increased by 104% between 1998 and 2010 which can largely be explained by inflation and a change in scope. The change in scope is the addition of the 2 – 345 kV transmission lines from Muskrat Falls Generating Station to Churchill Falls Generating Station, associated switchyards, environmental costs and other items such as insurance. Despite the additional costs, MHI considers the cost estimate to be within the accuracy range of an AACE Class 4 estimate (+50%/-30%) which is representative of a feasibility level study.

[39] CE-15 Rev.1 (Public), SNC Lavalin, "Muskrat Falls Hydroelectric Project – MF1010 – Review of Variants", March 2008, pg. 26

The cost estimate was prepared using an appropriate methodology that was applied in a comprehensive manner with relevant input data and assumptions. The scope of work identified for the estimate is in keeping with utility best practices. The resulting cost estimate appears to be consistent with the nature of the works proposed for construction, local conditions, and construction market conditions. The Base Cost Estimate for the works appears to be reasonable and should fairly represent the costs to be included in the Infeed Option. The approach adopted for project cost contingencies and escalation is also reasonable.

4.1.1 Muskrat Falls Generating Station Key Findings

The following key findings are noted from the Muskrat Falls development review:

- The proposed layout and design of the Muskrat Falls Generating Station appears to be well defined and consistent with good utility practices.
- The general arrangement of the permanent works is a reasonable proposal for the optimum development in terms of cost and construction duration.
- Based on the information provided, the design and construction of Muskrat Falls Generating Station is consistent with good engineering and construction practices, and should not pose any unusual risks for construction or operation of the facilities.
- The available studies have identified technical risks and appropriate risk mitigation strategies.
- The Muskrat Falls development cost estimate is within the accuracy range of an AACE Class 4 estimate even with the increased costs described above.

4.2 HVdc Converter Stations

The assessment of the technical work done by Nalcor on the HVdc converter stations, electrode lines, and associated switchyard equipment was undertaken by MHI as part of its technical review of the two options. It was carried out by HVdc experts on staff at MHI through meetings with Nalcor and reviews of a number of documents published by Nalcor relevant to the Gull Island development. Most project documentation on the Labrador-Island Link HVdc system was not available, such as the HVdc converter station single line diagram or a concept transition document, since the project definition changed in November 2010 with DG2. This lack of detailed information on the revised HVdc system hampered MHI's review.

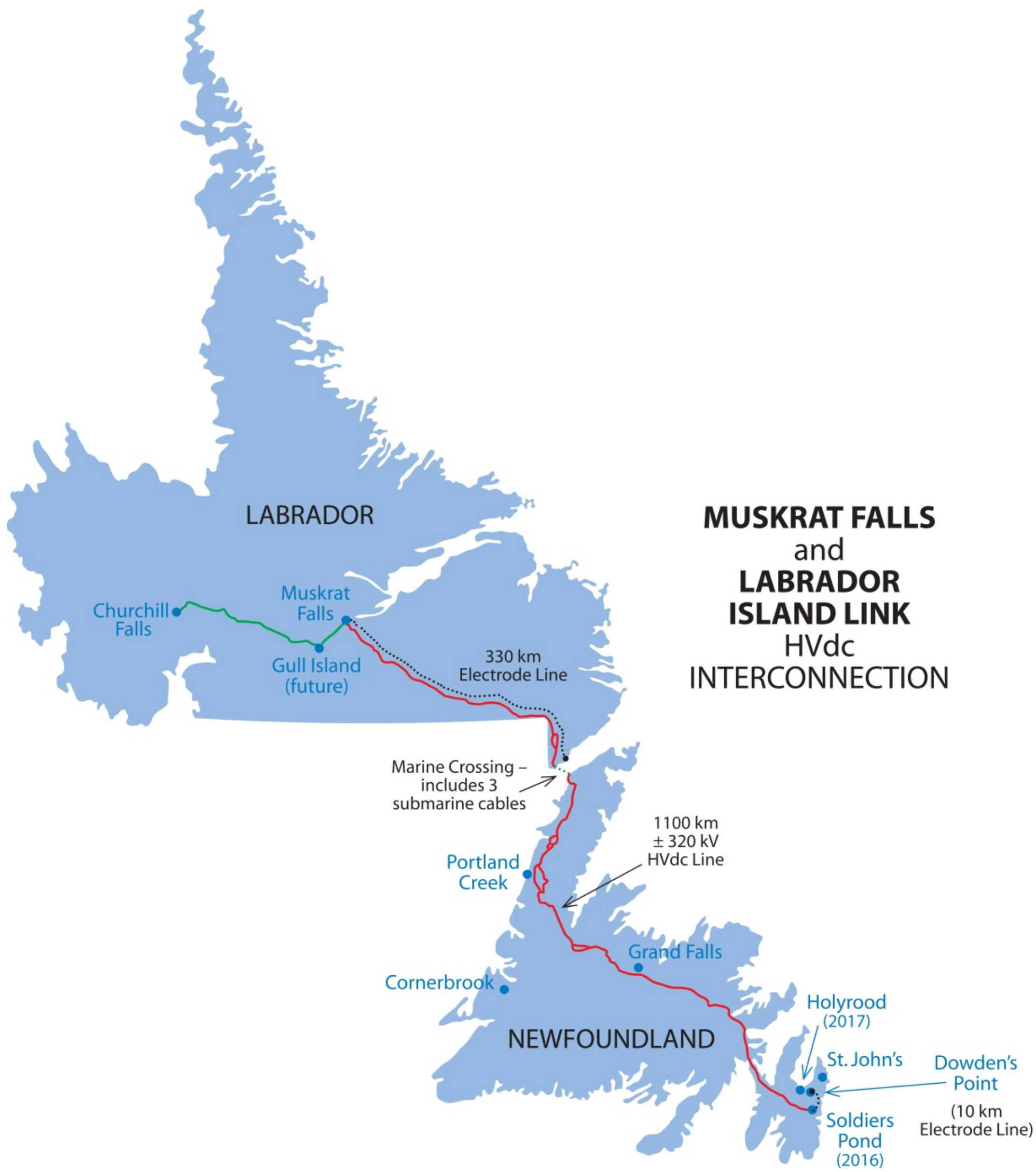

Figure 9: Muskrat Falls and Labrador Island Link HVdc Interconnection (locations are approximate)

The Labrador-Island Link HVdc System, as shown in Figure 9 above, is a 900 MW ±320 kV bipolar system for point-to-point HVdc transmission. It is comprised of a 900 MW converter station at Muskrat Falls (1350 MW with a 150% overload capability), associated ac and dc switchyards, and 330 km of transmission lines to the Strait of Belle Isle. At the Strait, there will be a transition station to a marine crossing with three fully rated submarine cables, one a spare, and appropriate cable protection systems crossing the strait and landing on the island. On the island shore, there will be another transition station connecting to switching equipment and the overhead HVdc transmission line to Soldiers Pond Converter Station near St. John's. At Soldiers Pond, there will be both ac and dc switchyards and ac and dc filters, plus 3 - 300 MVAr (volt-ampere reactive) high inertia synchronous condensers providing the required reactive support to successfully deliver the power to the island.

Two shoreline electrodes are included in this system. The first electrode line from the Muskrat Falls converter station will follow the HVdc transmission line (or be mounted on the same tower) to an appropriate grounding point at the Strait of Belle Isle. The second electrode line will emanate from Soldiers Pond approximately 10 km to the electrode site near Dowden's Point in Conception Bay.

The DG2 cost estimates for the converter stations were reviewed, compared against industry benchmarks, and were found to be reasonable when costs identified for overload capabilities were included.[40]

Nalcor's cost estimate for system upgrades includes three 300 MVAr synchronous condensers plus the conversion of two generating units at Holyrood Thermal Generating Station as well as the addition of several high voltage breakers. MHI finds that these estimates are low but are within the bands of cost estimate variability and thus are reasonable as inputs to the DG2 screening process and CPW analysis.

MHI notes that there was no comprehensive HVdc system risk analysis review for operations and maintenance for the overall HVdc transmission system including converter station equipment, transmission lines, or converter station control, protection and communications. MHI recommends that this operational design risk analysis be completed in conjunction with the development of the HVdc converter station specification so that any additional requirements may be included.

4.2.1 HVdc Converter Stations Key Findings

Key findings from MHI's review of the HVdc converter stations are as follows:

- The design parameters available to date for review are reasonable for the intended application, which has a basic requirement to transmit 900 MW over 1100 km of transmission line and inject this power into the island electrical system at Soldiers Pond with appropriate voltage and frequency control.

- The choice of line commutated converter (LCC) HVdc technology is mature and robust for the Labrador-Island Link HVdc transmission system. Newer technology exists with the recent

[40] CE-51, Nalcor, Technical Note: "Muskrat Falls Generation Facility and Labrador – Island Transmission Link, Overview of Decision Gate 2 Capital Cost and Schedules", August 2011

introduction of voltage source converter (VSC) systems. In a response to an RFI, Nalcor identified that VSC options will be considered if there are technical and financial advantages to do so. It is important to note that VSC systems of the size and length of the Labrador-Island HVdc system have not yet been built and operated anywhere in the world.

- The total cost estimate for the HVdc converter stations and electrodes based on an AACE Class 4 estimate are reasonable for DG2 purposes. The costs for the synchronous condensers are low but are still within the range of an AACE Class 4 estimate.

4.3 HVdc Transmission Lines

MHI has reviewed the design information provided by Nalcor for the Infeed Option as it pertains to risk and reliability. The appropriate design criteria for the proposed Labrador-Island Link HVdc transmission line is the "Design Criteria of Overhead Transmission Lines" code (International Standard CEI/IEC 60826:2003) with Canadian deviations in CSA Standard CAN/CSA-C22.3 No. 60826:06.

4.3.1 Reliability Based Transmission Line Design

MHI finds that Nalcor's decision to adopt the IEC Standard and CSA Code for the design reliability criteria is appropriate. Review of the exhibits and reports provided by Nalcor indicate that much effort has gone into gathering historical weather and infrastructure performance data. This information is essential when designing with reliability based methods for new transmission lines. Reliability based design uses a statistical approach based on probable return periods.

Nalcor's Exhibit 106, page 8, has introduced a suitable definition of a return period from the IEC standard used to characterize transmission line reliability:

> *"Simply put, the return period is a statistical average of occurrence of a climatic (weather load) event that has a defined intensity (ice and/or wind load) and is often described in terms of years. For example, a one in 50 year (1:50) event will occur on average once every 50 years."*

Exhibit 106 describes the adoption of the "Design Criteria of Overhead Transmission Lines" CEI/IEC 60826:2003 with Canadian deviations in CAN/CSA-C22.3 No. 60826:06 as the National Standard of Canada. The document also describes the process followed by Nalcor in its decision to use reliability based design as outlined in this same standard.

Exhibit 106 refers to the selection of reliability levels as described in Section A.1.2.5 page 125 of the 60826 IEC: 2003 document which is presented below in full.

> *A.1.2.5 Selection of Reliability Levels*
>
> *Transmission lines are typically designed for different reliability levels (or classes) depending on local conditions, requirements and the line duties within a supply network. Designers can choose their reliability levels either by calibration with existing lines that have had a long history of satisfactory performance or by optimization methods found in technical literature.*

In all cases, lines should at least meet the requirements of a reliability level characterized by a return period of loads of 50 years (level 1). An increase in reliability above this level could be justified for more important lines of the network as indicated by the following guidelines:

It is suggested to use a reliability level characterized by return periods of 150 years for lines above 230 kV. The same is suggested for lines below 230 kV which constitute the principal or perhaps the only source of supply to a particular electric load (level 2).

Finally, it is suggested to use a reliability level characterized by return periods of 500 years for lines, mainly above 230 kV which constitute the principal or perhaps the only source of supply to a particular electric load. Their failure would have serious consequences to the power supply.

The applications of the reliability for overhead lines, including corresponding voltage levels, may be set differently in various countries depending on the structure of the grid and the consequences of line failures. The impacts on other infrastructure installations such as railroads and motorways should be considered as well in the establishment of reliability criteria.

When establishing national and regional standards or specifications, decisions on the reliability level should be made taking into consideration also the experience with existing lines.

Nalcor states in Exhibit 106 that, since the existing 230 kV ac system is designed to a lesser reliability level, there is no justification to increase the reliability level of the HVdc link as the ac transmission system would fail for an event greater than the 1:50 year return period.

Considering the directions given in the IEC Standard, the voltage level of the Labrador-Island Link HVdc transmission line, the importance of this HVdc transmission line, and the local historical data gathered by Nalcor during the investigation of the Avalon Peninsula upgrade project, at a minimum the ±320 kV HVdc line should be designed to a return period of 1:150 years when an alternate supply is available. Nalcor should also give consideration to an even higher reliability level return period in the remote alpine regions[41]. MHI recommends that the HVdc transmission line be designed to a 1:500-year return period for the Island power system without an alternate supply. MHI considers this a major issue and recommends that Nalcor adhere to these criteria laid out in the IEC Standard for the HVdc transmission line design. Design for less than 1:150 year return period is contrary to best practices carried out by utilities in Canada, and does not reflect current industry practices which follow IEC 60826:2003.

No design optimization plan has been provided for the review or justification of the reduced transmission line reliability.

[41] Exhibit 97, Page 8. Alpine regions are defined as Southeastern portion of Labrador, two areas in the Long Range Mountains, and one small section in central Newfoundland.

Nalcor has estimated that the additional cost to build the transmission line to a 1:150 year return period is $150 million[42]. MHI, based on prior estimates for similar projects, confirms that the estimated additional cost of a $150 million dollars for moving from a 1:50 year return period to a 1:150 year return period is reasonable.

4.3.2 Transmission Design Review and Route Selection

As stated in the response to MHI-Nalcor-71, "The design details requested are not available as these are the subject of detailed design efforts by SNC Lavalin and will not be completed before 2012". MHI cannot provide comment on the overall tower design as none of the tower loading conditions were provided (i.e., construction loads, maintenance loads, torsional loads, and broken conductor scenarios), and only a few of the climatic loads were given. Further, MHI is unable to comment on the appropriateness of the route selection or risk analysis for the transmission line.

4.3.3 Cost Evaluation of Overhead Transmission Line Estimate

MHI has reviewed the cost estimate for the HVdc overland transmission line supplied in the confidential exhibit "Overview of Decision Gate 2 Capital Costs"[43]. The DG2 capital cost value falls inside the typical range of capital construction estimates for this type and length of transmission line. Nalcor's estimate is at the low end of the range.

4.3.4 Conclusions

Reliability based design is an appropriate method for the Infeed Option transmission line since there has been extensive meteorological analysis conducted. To support the design process, historical strength data for existing transmission lines were available from the work completed as part of the transmission line upgrade on the Avalon Peninsula.[44]

Considering the directions given in the IEC Standard, the voltage level of the Labrador-Island Link HVdc transmission line, the importance of this line, and the local historical data gathered by Nalcor, at a minimum the ±320 kV HVdc line should be designed to a return period of 1:150-year when an alternate supply is available. For this scenario consideration should also be given to an even higher reliability return period in the alpine regions[45] which are impacted by significantly greater ice and wind loads. The Labrador-Island HVdc line should be designed to a 1:500 year return period when there is no alternate supply.

Nalcor's exhibit 106 refers to the adoption of a 1:50 year return period for new 230 kV transmission line design and states that a 1:50 year return period is justifiable for the ±320 kV HVdc line. The response to

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[42] Response to RFI PUB-Nalcor-15
[43] CE-51, Nalcor, "Technical Note: Muskrat Falls Project:–Muskrat Falls Generation Facility and Labrador – Island Transmission Link Overview of Decision Gate 2 Capital Cost and Schedule Estimates", August 2011.
[44] Exhibit 6, System Planning Department, Newfoundland and Labrador Hydro, "Technical Note: Labrador-Island HVdc link and Island Interconnected System Reliability," October 2011.
[45] Exhibit 97, Page 8. Alpine regions as defined as Southeastern portion of Labrador, two areas in the Long Range Mountains, and one small section in central Newfoundland.

RFI PUB-Nalcor-13 also documents the 1:50 year return period as suitable for the Labrador-Island Link HVdc transmission line when considered together with the addition of the Maritime Link. As specified by the IEC/CSA Standard, there is a requirement to design to a 1:150 or 1:500 year return period depending on the criticality of the transmission line. Nalcor states that since the existing 230 kV ac system is designed to a lesser reliability level, there is no justification to increase the reliability level of the HVdc link as the ac transmission system would fail for an event greater than 1:50 year return period. MHI considers this to be a major issue and it is contrary to best practices carried out by utilities in Canada for transmission line design, and does not reflect current industry practices which follow IEC60826:2003.

4.3.5 HVdc Transmission Lines Key Findings

The key findings from the HVdc transmission line review are as follows:

- Nalcor has selected a 1:50-year reliability return period (basis for design loading criteria) for the HVdc transmission line, which is inconsistent with the recommended 1:500-year reliability return period outlined in the International Standard CEI/IEC 60826:2003 with Canadian deviations in CSA Standard CAN/CSA-C22.3 No. 60826:06, for this class of transmission line without an alternate supply. In the case where an alternate supply is available, the 1:150-year reliability return period is acceptable. In this latter scenario, Nalcor should also give consideration to an even higher reliability return period in the remote alpine regions[46]. MHI considers this a major issue and strongly recommends that Nalcor adhere to these criteria for the HVdc transmission line design. The additional cost to build the line to a 1:150 year return period is approximately $150 million.

- The capital cost estimate of the transmission line at DG2is reasonable, but at the low end of the range for this type of construction utilizing industry benchmark costs as a comparison. A design based on a 150-year return period could be accommodated within the variability of an AACE Class 4 estimate at this stage of development for the entire Labrador-Island Link HVdc project.

4.4 Strait of Belle Isle Marine Crossing

The Strait of Belle Isle (SOBI) marine crossing is a critical component of the Labrador-Island Link HVdc transmission line and will consist of three ±350 kV submarine cables in a 36 km long corridor across the Strait. The cables will have a shore approach with a landing site in the area of L'Anse Amour beach in Forteau Bay on the Labrador side, and in the area of Mistaken Cove on the Newfoundland side.

[46] Exhibit 97, Page 8. Alpine regions are defined as Southeastern portion of Labrador, two areas in the Long Range Mountains, and one small section in central Newfoundland.

MHI engaged CESI, an external consultant specializing in submarine cable crossings, to evaluate the studies and reports conducted by Nalcor's consultants of the proposed Strait of Belle Isle marine crossing. CESI's qualifications are described in Volume 2, Section 13.

In reviewing the marine crossing, MHI met with Nalcor's staff and their consultant C-CORE. A number of documents were also reviewed including:

- several feasibility studies
- risk reports
- cost estimates
- specifications
- design concept documents
- confidential exhibits CE-40 through 44
- Exhibit 33: Summary of Ocean Current Statistics for the Cable Crossing SOBI
- Exhibit 34: Review of Fishing Equipment – Strait of Belle Isle
- Exhibit 35: Nalcor's SOBI Iceberg Cable Risk
- Exhibit 37: SOBI Decision Recommendation Oct 12, 2010
- and CE-55 Request for Proposal (RFP) No. LC-SB-003 "Strait of Belle Isle Submarine Cable Design, Supply, and Install."

4.4.1 Cable Specifications

The conductor has been specified as ±350 kV single core aluminium or copper cable with mass impregnated (MI) paper insulation. The cables will be armoured to match the required pulling tension strength and provide for cable protection when building rock berms on the seafloor. The nominal cable voltage rating will be ±320 kV with a nominal current carrying capability of 1286 A (450 MW), continuous rating of 1929 A at 1.5 pu, and a transient rating of 2572 A (2 pu for 10 minutes)[47]. These ratings match the HVdc converter station capabilities.

The selection of the core area is dependent on losses, the thermal properties of the cable, and the surrounding environment. The final cable size selection will be based on a detailed engineering analysis performed by the supplier.

4.4.2 Cable Route

The Strait of Belle Isle marine crossing is extremely complex and poses numerous challenges for cable installation and protection. Challenges include sea currents, icebergs, pack ice, tidal forces, rock placement, varying water depths, fishing activities and vessel traffic.

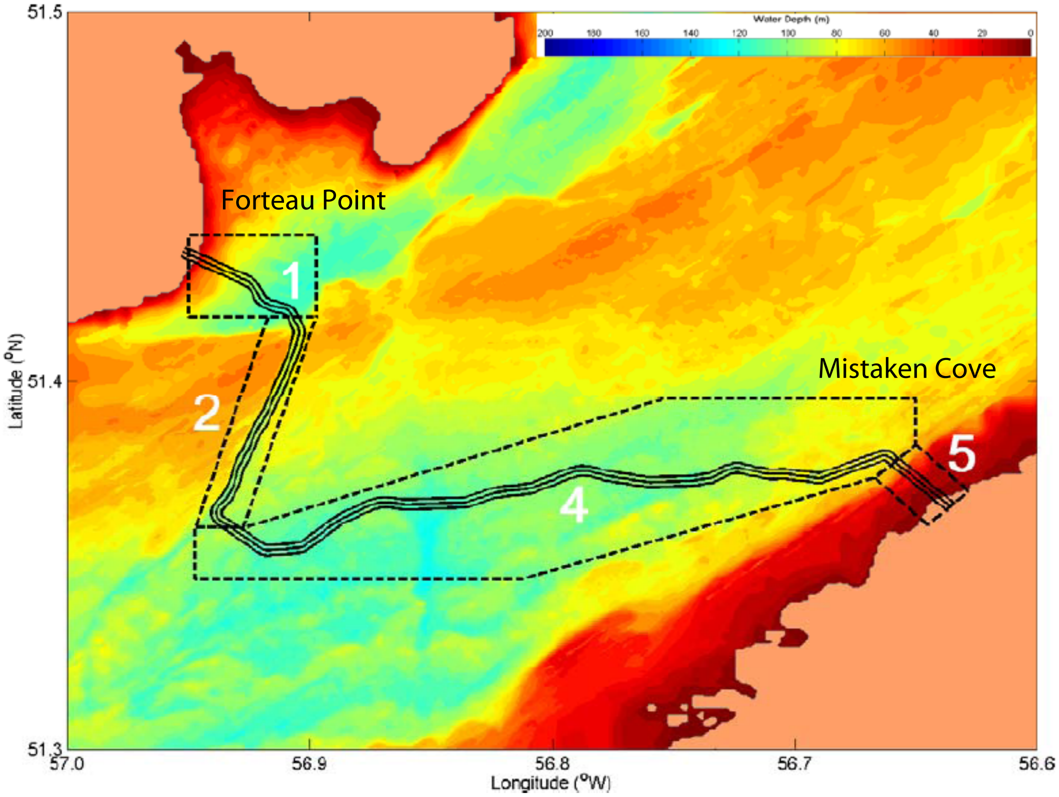
The cable corridor is shown below in Figure 10. This corridor takes into account the relevant landfall and possible protection methods. The estimated length is approximately 36 km, with roughly 32 km on the sea floor. The route is depicted within a 500-m-wide corridor with a 1500-m diameter circular

[47] CE-55 Rev 1 (Public), Nalcor, "Request for Proposal (RFP) No. LC-SB-003 Strait of Belle Isle Cable Design, Supply, and Install", August 2011

sea floor piercing target zone for horizontal directional drilling. Zone 3 is not shown but has been known as the Eastern Corridor and was not used due to the depth of water and potential for iceberg scouring.

MHI generally agrees with Nalcor's selection of the preferred alternative which included horizontal directional drilling as a means of shore approach for the cable and laying the cable on the seabed with a rock berm protection scheme. Nalcor's recommended design has been carefully formulated based on the synthesis of the conclusions reached in the various study documents.

Figure 10: Strait of Belle Isle Marine Crossing



4.4.3 Iceberg Risks

C-CORE and Fugro Geo Surveys conducted a review of the Strait of Belle Isle crossing as this area is frequented by icebergs which pose a hazard to any cables either placed on or trenched into the seabed. Their report described the application of a model to assess iceberg risk to cables laid on the seabed in the Strait of Belle Isle.

The iceberg scour data was the first systematic assessment of the scour regime in this area. The observed spatial distribution of iceberg scours was unexpected with the majority of scours occurring in deeper water. However, these scours could have taken place in previous glacial periods. This cannot be positively confirmed and as such there is a risk generally in the 70 – 75 metre water depth range. The iceberg risk analysis used a state of the art Monte Carlo based iceberg contact simulation that models the distribution of iceberg groundings and incidents where iceberg keels are close enough to contact a cable on the seabed. Icebergs have been observed to roll and this was considered in the simulations as an increased roll rate increases the risk to scouring. The separation distance between cables was compared to observed scour length distributions and it was noted that the probability of contacting multiple cables is reduced with increased separation distance. The software used to model iceberg contact risks was developed by C-CORE and verified through other research on the Grand Banks, Conception Bay, and with field observations in the Strait of Belle Isle.

C-CORE has concluded that the iceberg grounding risk to the cables in the Strait of Belle Isle is a 1:1000 year event at a cable depth greater than 70 meters, and an iceberg roll rate of one every ten days. Increasing the roll rate to one roll every day increases the risk to approximately a 1:400 year event at the same depth.

4.4.4 Marine Crossing Costs

The total base cost estimate for the marine crossing in DG2 was reviewed by MHI. The cost estimate prepared by CESI has confirmed Nalcor's cost estimate is within the range of an AACE Class 4 cost estimate.

4.4.5 Strait of Belle Isle Key Findings

MHI's key findings on the Strait of Belle Isle marine crossing are as follows:

- The selection of a ±350 kV mass impregnated cable is an appropriate technology selection for the application of an HVdc marine crossing operating at ±320 kV. Other technologies, such as cables with cross-linked polyethylene insulation, have been type tested for this application at ±320 kV but none have been used at this voltage level on a marine HVdc project in the world today.
- Nalcor's total base cost estimate for the marine crossing at DG2 was reviewed by CESI, an independent engineering firm experienced in HVdc marine crossings. Nalcor's estimate is within the range of an AACE Class 4 cost estimate.
- The iceberg risks are perceived to be significant; however, the application of horizontal directional drilling for shore landings, years of iceberg observations and research performed by C-CORE (a local consulting firm) on the Grand Banks for the various oil projects, and careful route selection across the Strait of Belle Isle have quantified the risks to be less than one iceberg strike in 1000 years. This risk is further mitigated with rock berms, largely for fishing equipment and anchor protection, and a spare cable with separation distance between them of 50 to 150 metres. The research performed by C-CORE found that the risk of a multiple cable contact by icebergs was reduced with greater separation of the cables. Additional research, monitoring of iceberg roll rates, and bathymetric surveys of earlier iceberg scours should be done to provide a level of validation to further tune the iceberg strike risk model.

- Application of a spare cable with as much separation as practical is a prudent design feature of the Strait of Belle Isle marine crossing considering the potential difficulties of bringing in repair equipment at certain times of the year.