Date : 8/2/2012 4:44:53 PM
From : "Paul Wilson"
To : "Bown, Charles W."
Cc : "Allen Snyder" , "Mack Kast (mkast@mts.net)"
Subject : MHI Decision Gate 3 review report draft
Attachment : Draft Consolidated DG3 report (August 2 2012).pdf;

Hello Charles, here is the PDF version of the document. I have reiterated the original email on the off chance that if was filtered out by the mail systems.

Hello Charles, I am pleased to send you the first draft of the technical portion of the DG3 review report for your review and comment. There are still a few sections that will need some work, particularly the Holyrood options, and the AC integration studies sections. Although there is good information in the report, the AC integration studies are relatively technical so they may require a little work to make to simplify with language relevant for the CPW review of DG3. The CPW analysis (waiting on the visit and data), Conclusions and Executive Summary (done last) are yet to be completed. Let me know if this is okay to send to Nalcor for their review.

I am on holidays for the next two weeks returning to the office on the 20th. I will be back in blackberry range after the 10th of August if you have to reach me. As an alternative, you can call Mr. Al Snyder at the numbers below if you have issues to discuss on the report or feedback on the contents.

Allen Snyder
[redacted]
Canada
Home: +1 (204) [redacted]123
cabin: +1 (807) [redacted]355
Mobile: +1 (204)[redacted]756
E-mail: amsnyder@mhi.ca

I would try each of the numbers starting with mobile, cabin, then home to contact Al Snyder.

Nalcor has schedule the CPW visit for August 15 – 17th. Mack Kast is scheduled to fly down on the 14th for those series of meetings. I will inform Brian Crawley of this so Nalcor is prepared.

The Wind study still requires the contract to be executed. If the contact is ready to send to us, you may send it to Danny Northcott at

dnorthcott@hvdc.ca
+1 204 989-1248

Danny will be pulling together the technical work on the wind study while I am away. Nalcor plans to send us their completed wind study the week of the 6th so we can start that phase of the review.

Congratulations on the Emera deal signed on Monday. I imagine that has been keeping you very busy this week. I will talk to you once I return.

Regards,

Paul Wilson, P. Eng.
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Manitoba Hydro International's

Decision Gate 3 review of the Muskrat Falls and Labrador Island HVdc Link and the Isolated Island options

DRAFT

Prepared for:
Hon. Jerome Kennedy, Q.C.
The Minister of the Department of Natural Resources
Government of Newfoundland and Labrador

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August 2, 2012

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Mack Kast, CA
Allen Snyder, P.Eng., MBA.

Approved by:

Paul Wilson, P.Eng.

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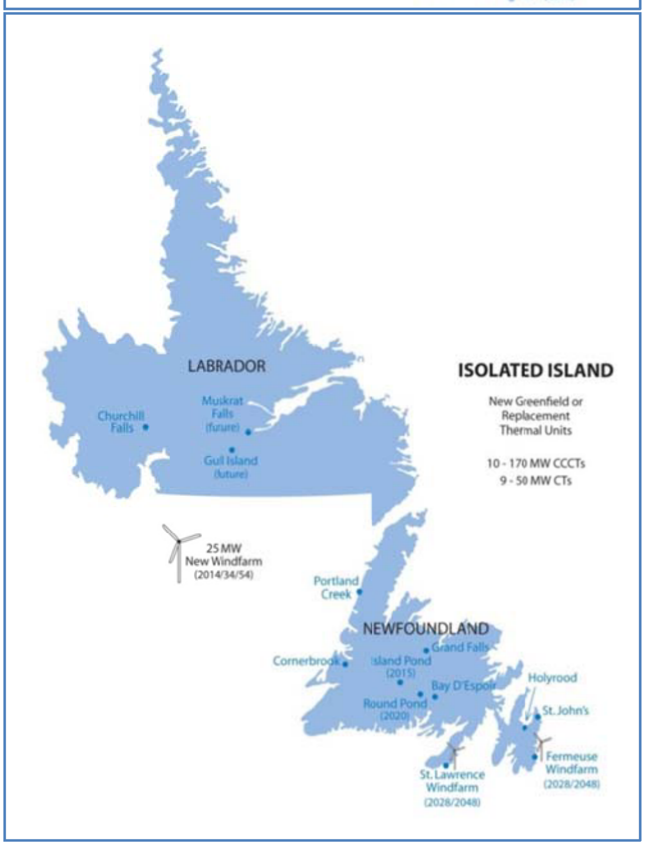
Permit to Practice

Professional Engineering and Geoscientists of Newfoundland and Labrador - No. 0474


LABRADOR
MUSKRAT FALLS
and
LABRADOR
ISLAND LINK
HVdc
INTERCONNECTION
900 MW LIL HVdc
23 MW Portland Creek
7 - 50 MW CTs
1 - 170 MW CCCT
Churchill Falls
Muskrat Falls
Gull Island (future)
Portland Creek
Cornerbrook
Grand Falls
NEWFOUNDLAND
Holyrood (2017)
St. John's
Soldiers Pond (2016)


LABRADOR
ISOLATED ISLAND
New Greenfield or
Replacement
Thermal Units
10 - 170 MW CCCTs
9 - 50 MW CTs
Churchill Falls
Muskrat Falls (future)
Gull Island (future)
25 MW
New Windfarm
(2014/34/54)
Portland Creek
NEWFOUNDLAND
Cornerbrook
Grand Falls
Island Pond (2015)
Bay D'Espoir
Round Pond (2020)
Holyrood
St. John's
Fermeuse Windfarm (2028/2048)
St. Lawrence Windfarm (2028/2048)

Executive Summary

(to be added last)

What did MHI do?

What did MHI find?

What did MHI conclude?

What did MHI recommend?

Table of Contents

1 Introduction

The Government of Newfoundland and Labrador retained Manitoba Hydro International Ltd. (MHI) to provide an independent technical assessment of two generation supply options, as prepared by Nalcor Energy (Nalcor), for the future supply of electricity to the Island of Newfoundland. The two generation supply options are the Interconnected Island option and the Isolated Island option. The scope of this assessment is limited to Nalcor's revisions to the two generation supply options following Decision Gate 2 (DG2), from November, 2010. MHI's assessment is summarized in this current report, and will be used in preparation for

The Decision Gate process is a project management process designed to allow effective decision making for projects. Nalcor has passed the Decision Gate 2 milestone November 2010 and the next stage gate or Decision Gate 3 (DG3) is the milestone to determine whether to proceed with the project. Decision Gate 3 is also called project sanction.

MHI's report is preceded by a report prepared by the Newfoundland and Labrador Board of Commissioners of Public Utilities on March 30, 2012[1]. The Board's report reviewed the two generation supply options for the Government of Newfoundland and Labrador to determine whether the Interconnected Island Option represented the least-cost option for the supply of power to the Island Interconnected customers over the period of 2011-2067 as compared with the Isolated Island option. The Board's report also embodied the work done by Manitoba Hydro International as their independent expert as part of the Decision Gate 2 review.

MHI's review of the work completed by Nalcor since Decision Gate 2 in preparation for Decision Gate 3 includes an assessment of the Cumulative Present Worth (CPW) analysis of the various components for each of the two options, including a reasonableness assessment of all inputs into that analysis. The tests of reasonableness for this assessment are generally defined as the work following:

- Good project management and execution practices
- Good utility practices of the majority of electrical utilities in Canada, while recognizing the unique electrical isolated system on the Island of Newfoundland and commonly accepted practice in Newfoundland and Labrador regarding the electrical system. Any practices unique to Newfoundland and Labrador are noted in this report. The review and technical assessment in the context of this scope of work determines if Nalcor's work was undertaken in accordance with good utility practices whereby the processes,

[1] Board of Commissions of Public Utilities, "Reference to the Board – Review of Two Generation Expansion Options for the Least-Cost Supply of Power to Island Interconnected Customers for the Period 2011-2067", March 30, 2012.

practices, and standards used in the development of the work follows generally acceptable practices, standards, and processes of a majority of the utilities in Canada.

A comparison of the two generation supply alternatives, the Interconnected Island option and the Isolated Island option, are outlined below in Figure 1 and Figure 2.

The Interconnected Island option is largely a hydroelectric generation plan (824 MW from the Muskrat Falls Generating Station and the 900 MW Labrador-Island Link HVdc system, and 23 MW from the Portland Creek Generating Station), with the addition of 520 MW of thermal generation using combustion turbines. Power from the Muskrat Falls Generating Station on the Lower Churchill River in Labrador is planned to be supplied to Newfoundland over the Labrador-Island Link HVdc system transmission line that would cross the Strait of Belle Isle. First power from the Muskrat Falls Generating Station is scheduled to be available in October 2017.

The Isolated Island option is largely a thermal generation plan (1,640 MW), with the addition of 77 MW of small hydroelectric-generating stations and 79 MW of wind power. The generation plan includes:

- Installation of environmental emissions controls at Holyrood (electrostatic precipitators, scrubbers and NOx burners) as per the Newfoundland and Labrador Government's policy directives
- Life extension projects at Holyrood with eventual replacement of the units in 2033 and 2036
- One 25 MW wind farm
- Two 27 MW wind farm replacements
- The 36 MW Island Pond Generating Station
- The 23 MW Portland Creek Generating Station
- The 18 MW Round Pond Generating Station
- 1 640 MW, composed of 50 MW combustion turbines and 170 MW combined-cycle combustion turbines. This includes 510 MW for replacement of the Holyrood units.

This review of the two generation supply options includes a more in-depth examination of the transmission line designs, ac integration studies, and HVdc converter station plans than was examined during the Decision Gate 2 review, as this material had not been available during that review. Detailed examination for the Muskrat Falls Generating Station, the Strait of Belle Isle marine crossing, and thermal power plants only include cost estimate and schedule details only as it relates to the project definition. The technical comments contained in this report are offered for Nalcor's consideration based on review of the available material, meetings with Nalcor, and MHI's past experience on similar projects. Comments of a significant nature that could potentially lead to impacts on the result of the CPW analysis are highlighted as such; the balance of the comments are for Nalcor to address as it sees fit in its detail designs.

For Decision Gate 3, the cost estimate accuracy range for all engineering estimates for the Muskrat Falls Generating Station and the Labrador-Island Link HVdc system was the Association for the Advancement of Cost Engineering (AACE), Class 3 (+30% to -20%). For the Isolated Island option, some costs were updated, whereas others were escalated to provide new base case numbers at the AACE Class 4 level that was used for Decision Gate 2.

This report is organized with the major elements of the Interconnected Island option being discussed first in Section 2. The items related to the Isolated Island option are discussed in Section 3, with the CPW financial analysis described in Section 6. A number of documents have been provided to MHI by Nalcor to assist in this review and these are described in Appendix A: Bibliography of Documents.

The Interconnected Island option, as detailed in Section 2, encompasses several generation items that are added to the system according to the generation master plan. These items and installation dates are shown in Figure 1. The time and sizing of new generation sources are essentially the same as in Decision Gate 2.

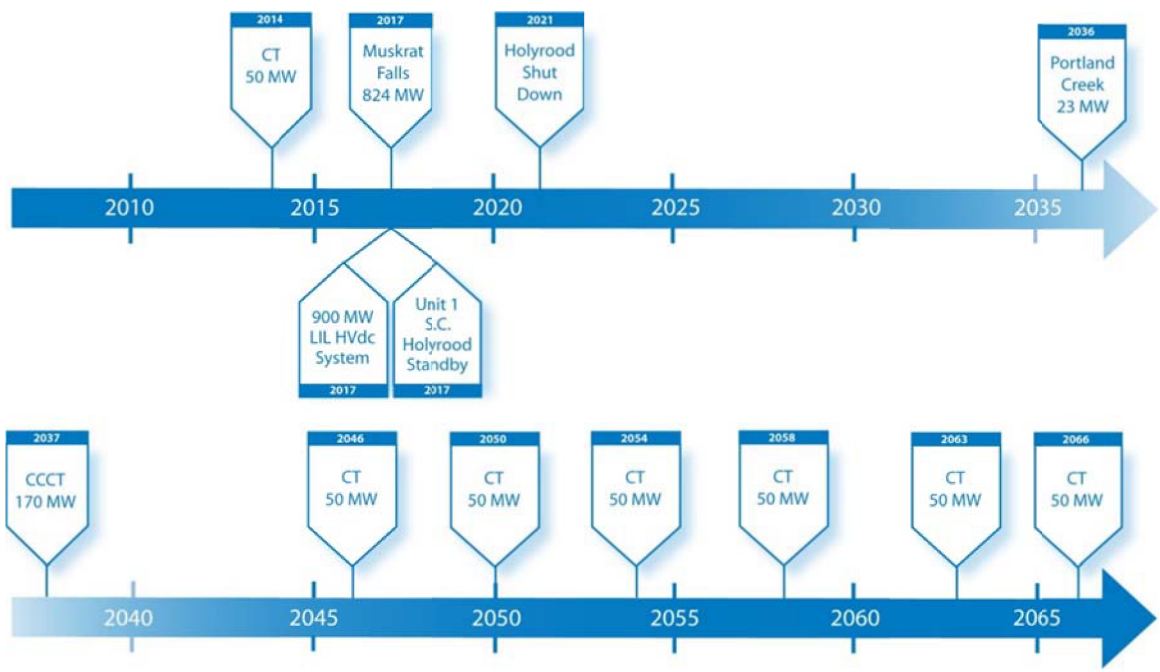


Figure 1: Project Time Line - Interconnected Island Option

The Isolated Island option as detailed in Section 3, encompasses several generation items that are added to the system according to the generation master plan. These items and installation dates are shown in Figure 2. The time and sizing of new generation sources are essentially the same as in Decision Gate 2.

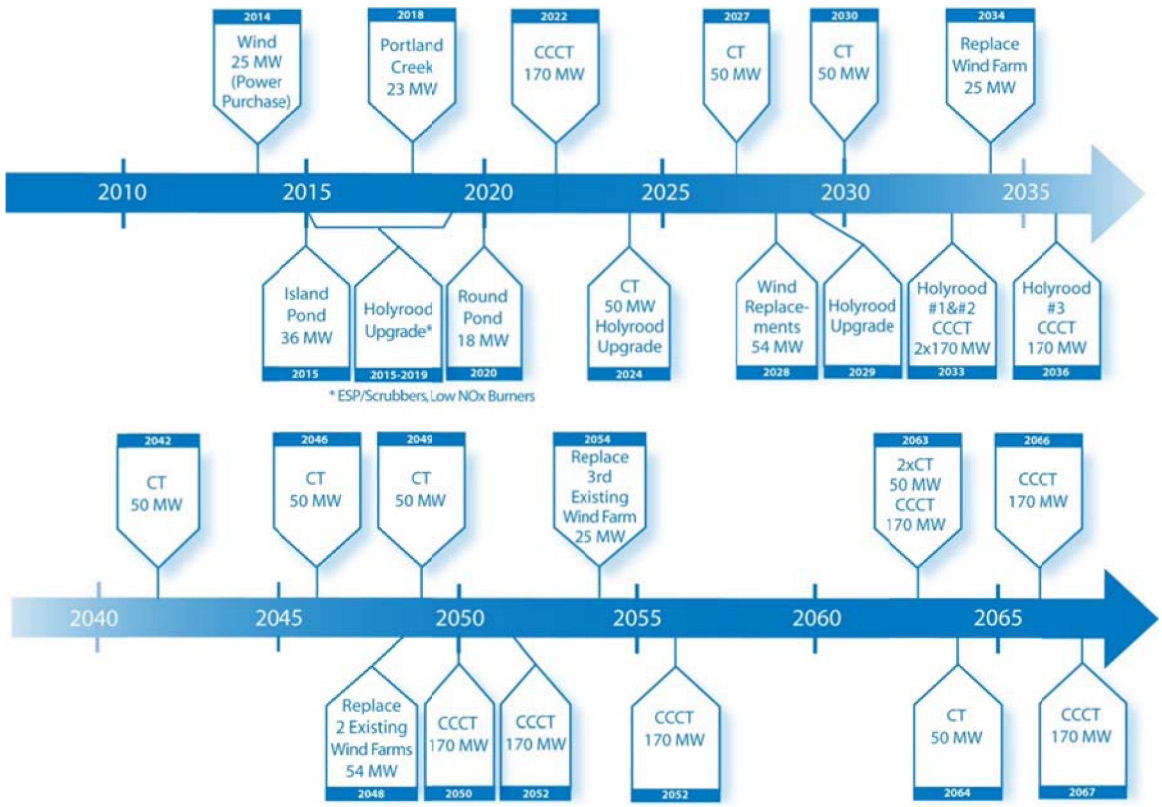


Figure 2: Project Time Line - Isolated Island Option

2 Interconnected Island Option

The Interconnected Island option is depicted in Figure 3 showing the HVdc transmission system, and important elements as part of the generation master plan.

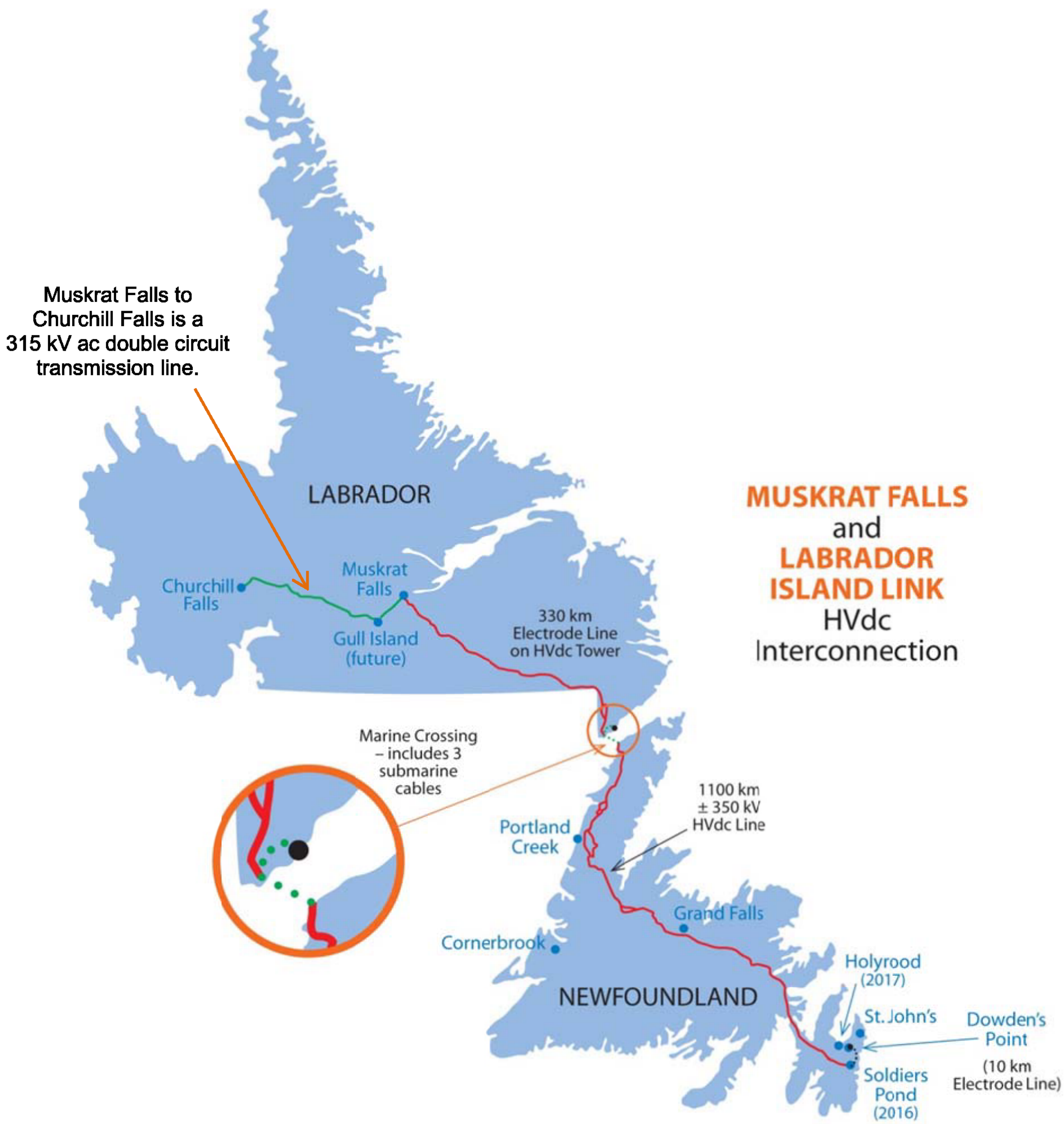


Figure 3: Interconnected Island Details

This section of the report describes the Load Forecast, ac integration studies undertaken by Nalcor, HVdc converter station and associated equipment, transmission system elements, the Strait of Belle Isle marine crossing, Muskrat Falls generating station, and other thermal and small generation sources added for this option. Detailed examination of the hydrology, reliability studies, or thermal supply options were not undertaken as part of this Decision Gate 3 review and this material did not change from the prior Decision Gate 2 review.

2.1 Interconnected Island Load Forecast

The purpose of this section is to analyze the 2012 Interconnected Island option to determine whether it was conducted with the due diligence, skill and care expected from an operation of this magnitude. This section outlines the differences between the Load Forecast for 2012 Interconnected Island option and that prepared in 2010, compares levels of forecast growth versus historical growth, and updates the forecast accuracy tables. The analysis focuses on the total electric energy peak requirements on the Island of Newfoundland. The data reviewed focuses on the 20-year forecast period (2012-2031). The extrapolated forecast (from 2031-2067) is also reviewed for total Island energy requirements and interconnected Island system peak.

2.1.1 Comparison of the 2012 Interconnected Island option Load Forecast and the 2010 Load Forecast

This analysis compares the forecasts prepared in 2012 and 2010. The 2010 Load Forecast was used as a basis for Decision Gate 2, and the 2012 Interconnected Island option is being used as the basis for Decision Gate 3. Generally, the 2012 energy and peak forecasts are higher over the 20-year forecast period. The 2012 energy and peak forecasts converge towards 2010 forecast levels over the extrapolation period and cross over around 2057 (see Figure 4 and Figure 5).

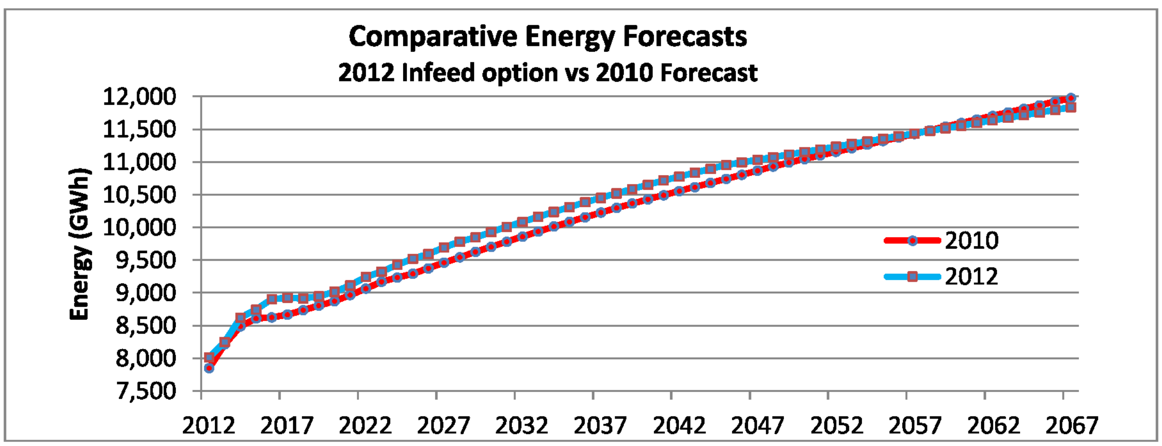


Figure 4: Comparative Energy Forecasts - the 2012 Interconnected Island option versus 2010 Load Forecast[2]

[2] CEnn, Nalcor, reference required.

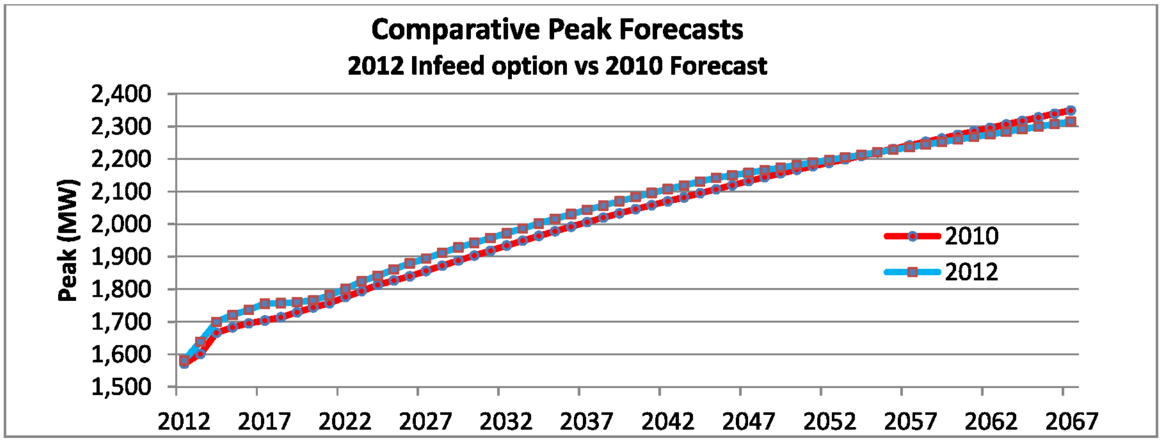


Figure 5: Comparative Peak Forecasts - the 2012 Interconnected Island option versus 2010 Load Forecast[3]

Since the econometric sector forecasts prepared in 2010 covered the period of 2010 to 2029, this comparative analysis has a forecast start year of 2012, a forecast mid-point year of 2020, and a forecast long-term year of 2029. The results are included in Table 1.

Table 1: Comparison of the 2012 Interconnected Island option and the 2010 Forecast - Net Difference

	Energy (GWh)					Peak (MW)
Year	Domestic	General Service	Industrial	Other	Energy	Peak
2012	177	-4	-53	44	164	10
2020	160	-67	37	14	144	22
2029	326	-156	37	14	222	41

In the year 2012, the 2012 Interconnected Island option predicts that total Island energy and peak requirements will be greater than the 2010 Load Forecast by 164 GWh and 10 MW, respectively. This increase is the result of a higher actual domestic load growth experienced in 2010 and 2011, caused by a significant number of new domestic customers and an increase in domestic weather-adjusted average use.

By 2029, the 2012 Interconnected Island option predicts that total Island energy requirements will be greater than the 2010 Load Forecast by 222 GWh. This increase is due to the higher domestic sector forecast, by 326 GWh, which is the result of a higher customer forecast and a higher average-use forecast.

Table 2 lists the differences between the 2012 Interconnected Island option and 2010 Load Forecast for the key economic assumptions and domestic consumption variables for the 2029 forecast long-term year. The higher domestic forecast for the 2012 Interconnected Island option (by 326 GWh) was due to a lower marginal price of electricity forecast (-1.17 cents),

[3] CEnn, Nalcor, reference required.

which encourages electricity consumption such as electric space-heating, and revises key economic assumptions prepared by the Newfoundland Department of Finance, which raised forecasts for personal disposable income (by $1,501) and population (by 6,500). By 2029, the domestic average-use forecast was increased by 984 kWh in the 2012 Interconnected Island option, primarily due to a lower marginal price of electricity forecast, a higher saturation of electric space-heating forecast (2.0%), and a higher personal disposable income per customer forecast. By 2029, the domestic forecast predicted a greater number of total customers (3,496) and electric space-heating customers (7,437), primarily due to a higher actual customer growth in 2010 and 2011 than previously forecast.

Table 2: Comparison of the 2012 Interconnected Island option and 2010 Load Forecast in 2029 - Net Difference

Forecast	Avg Use	Electric Space Heat Customers	Total Customers	Electric Space Heat%	Marginal Price	PDI	Population
2012 Interconnected Island option	17,015	178,824	254,627	70.2%	8.72	$15,196	513,200
2010 Load Forecast	16,032	171,387	251,131	68.2%	9.89	$13,695	506,700
Difference	984	7,437	3,496	2.0%	-1.17	$1,501	6,500

Manitoba Hydro International (MHI) considers the significant increase in the domestic forecast as an improvement over the 2010 Load Forecast because the 2012 Interconnected Island option is based on the higher customer growth and higher weather-adjusted average-use growth experienced over the last two years. The 2012 Interconnected Island option is also based on higher personal disposable income and population forecasts, which MHI considers more reasonable.

The higher domestic forecast was offset by a general service forecast that was 156 GWh lower, caused by a lower commercial business investment forecast, which was provided by the Department of Finance. The decrease in commercial business investment is questionable, considering that most other key economic assumptions were increased. Usually, an increase in the number of domestic customers and their relative prosperity will lead to an increase in general service investment and general service electricity consumption. Consequently, MHI considers the general service forecast prepared in 2010 as more reasonable and representative of an economy with moderate, consistent growth.

The industrial forecast was 37 GWh higher due the combination of a higher energy consumption forecast for Vale Newfoundland and Labrador Limited (Vale) and a lower energy consumption forecast for Corner Brook Pulp and Paper Limited (Corner Brook mill). The other sector forecast, which consists primarily of distribution and transmission losses, was increased by only 14 GWh. System losses will increase as a result of higher total electricity sales.

By 2029, the 2012 Interconnected Island option predicts that the total Island interconnected peak will be 41 MW more than the 2010 Load Forecast. This increase is the result of a higher electric space-heating customer forecast and a lower marginal price of electricity forecast. MHI considers the increase in the peak forecast as an improvement over the 2010 Load Forecast because the 2012 Interconnected Island option is based on a higher number of electric space-heating customers.

By 2020, the 2012 Interconnected Island option predicts that total Island energy and peak requirements will be greater than the 2010 Load Forecast by 144 GWh and 22 MW, respectively. The domestic forecast was increased by 160 GWh, the general service forecast was decreased by 67 GWh, the industrial forecast was increased by 37 GWh, and the other sector forecast was increased by 14 GWh. Generally, the differences in the 2020 forecast mid-point year are caused by the same factors that explained the differences for the 2029 forecast long-term year.

2.1.2 Comparison of the 2012 Interconnected Island option with Historical Growth

Table 3 compares the 2012 Interconnected Island option with historical growth. Total Island energy and peak requirements are expected to grow at a steady rate over the next 20 years. These forecasted growth levels are very similar to the historical growth experienced over the last 40 years. One apparent concern is that the total Island energy and peak forecasts over the extrapolation period (from 2031 to 2067) are too low. The extrapolated energy forecast (51 GWh) is only 44% of the load expected over the 20-year forecast growth rate (115 GWh). The extrapolated peak forecast (10 MW) is only 48% of the load expected over the 20-year forecast growth rate (21 MW). These reductions in future growth are significant and may be overly conservative. For example, the 10 MW of annual peak growth can be achieved by adding only 1 565 electric space-heating customers per year, which is much lower than the average addition of 3 551 electric-space heating customers per year over the last ten years. The extrapolated growth rates are lower due to lower growth of electric space-heating as the market becomes saturated and the assumption of no new industrial loads will locate on the Island over the extrapolation period.

Table 3: Annual Growth per Year – The 2012 Interconnected Island option and Historical Growth

Sector	Historical Growth Rate			Interconnected Island option	
				Forecast Growth Rate	Extrapolated Growth Rate
	1971-2011 (40-Year)	1991-2011 (20-Year)	2001-2011 (10-Year)	2011-2031 (20-Year)	2031-2067 (36-Year)
Domestic (GWh)	77	42	65	56	NA
General Service (GWh)	44	24	32	21	NA
Industrial (GWh)	-13	-58	-132	31	NA
Other (GWh)	8	3	13	7	NA
Island Energy (GWh)	117	12	-23	115	51
Island Peak (MW)	25	3	11	21	10

The 20-year forecast growth rate for the domestic sector (56 GWh) is expected to be less than the 10-year historical growth rate (65 GWh). This is because most electric space-heating conversions have already occurred, so fewer conversions are expected in the future. Conversely, the 20-year forecast growth rate is expected to be greater than the 20-year historical growth rate (42 GWh). This is because the economy is expected to outperform the historical period that included the economic downturn of the 1990s. MHI considers the 20-year forecast growth rate for the domestic sector to be reasonable.

The 20-year forecast growth rate for the general service sector (21 GWh) is expected to be similar to the 20-year historical growth rate (24 GWh). However, the historical growth rate covered a period of economic downturn in the 1990s, and since another economic downturn is not anticipated in the future, the 2012 Interconnected Island option forecast for the general service sector seems to be conservative. MHI considers the 2010 Load Forecast for the general service sector to be more reasonable and representative of an economy with moderate, consistent growth. By 2029, the 2010 Load Forecast predicts that the general service load will increase by 156 GWh, or 8 GWh per year, over the 20-year forecast period. This would raise the 20-year forecast growth rate to 29 GWh per year, which would be similar to the 10-year historical general service growth rate (32 GWh).

The 20-year forecast growth rate for the industrial sector (31 GWh) is expected to grow due to the expansion of Vale and the assumption of continued operation of the Corner Brook mill. The viability of the Corner Brook mill operation is outside the scope of this analysis and should be evaluated in the framework of a sensitivity analysis during the public review process.

The 20-year forecast growth rate for the other sector (7 GWh) is expected to be similar to the 40-year historical growth rate (8 GWh). The 20-year forecast growth rate for total Island energy (115 GWh) is expected to be similar to the 40-year historical growth rate (117 GWh).

The 20-year forecast growth rate for total Island peak (21 MW) is expected to be 16% lower than the 40-year historical growth rate (25 MW).

2.1.3 Forecast Accuracy

A reasonable performance measure for forecast accuracy is a maximum forecast deviation of ±1% per year. A 10-year-old forecast, for example, should be within ±10% of the actual energy load observed. Table 4 measures forecast accuracy in terms of percentage of deviation from the actual load.

Table 4: Energy Forecast Accuracy Measured in Percentage of Deviation from the Actual Load

Years of History	1	2	3	4	5	6	7	8	9	10
Domestic (%)	-1.4%	-2.2%	-3.2%	-3.9%	-4.4%	-4.8%	-6.0%	-7.4%	-8.5%	-10.2%
General Service (%)	0.1%	0.1%	0.1%	0.3%	0.2%	0.4%	0.3%	0.5%	1.5%	2.5%
Industrial (%)	5.0%	13.3%	26.0%	40.8%	59.6%	70.4%	88.0%	100.5%	122.4%	125.3%
Other Loads (%)	-3.1%	-4.3%	-5.0%	-6.7%	-7.9%	-8.7%	-8.1%	-7.6%	-7.1%	-9.2%
Island Energy (%)	0.3%	1.7%	3.5%	5.8%	8.7%	10.4%	12.4%	13.5%	15.9%	15.3%

Past domestic forecasts have been reasonable, but have under-predicted future energy needs at a rate of 1% per year into the future. The domestic forecast under-predicted energy consumption in 63 of the 65 cases analyzed. This under-prediction generally results from conservative assumptions for key economic variables and not from the model specification. Past forecasts for the general service sector have produced remarkably good results.

The industrial sector forecast has not performed well. The assumption of continued operation of the pulp and paper industry was overly optimistic, causing problems that have affected the industrial forecast accuracy. The total Island energy forecast is prepared by summing the four sector forecasts, and consequently, the industrial forecast has affected the results for total Island energy requirements. Table 5 shows that all of the total Island energy forecast deviation can be associated with the overly optimistic industrial forecast. In fact, the Island energy requirements would be under-forecast if the industrial forecast was accurate.

Table 5: Energy Forecast Accuracy Measured in GWh of Deviation from Actual Load

Years of History	1	2	3	4	5	6	7	8	9	10
Domestic (GWh)	-45	-72	-108	-130	-149	-163	-209	-260	-303	-366
General Service (GWh)	2	3	2	7	5	9	6	12	33	55
Industrial (GWh)	86	221	403	617	866	1,014	1,209	1,330	1,524	1,544
Other Loads (GWh)	-19	-26	-30	-40	-47	-52	-50	-47	-44	-58
Island Energy (GWh)	24	127	268	454	675	809	956	1,035	1,209	1,175

Table 6 measures forecast accuracy in terms of percentage of deviation from the actual peak load observed. The Newfoundland Peak demand regression equation accounts for 80%

of the interconnected Island demand and has performed extremely well. The other peak forecast, which includes the peak demand associated with the Newfoundland and Labrador Hydro (NLH) rural system, the NLH transmission system, and the industrial customers served by NLH, has not performed well. The interconnected Island system peak demand has been over-predicted as a result of a high industrial peak demand forecast. The interconnected Island system peak demand forecast is prepared by summing the two sector forecasts, and as a result, the other loads (rural, transmission & industrial) peak demand forecast has affected the overall results for the interconnected Island peak load.

Table 6: Peak Forecast Accuracy Measured in Percentage of Deviation from the Actual Load

Years of History	1	2	3	4	5	6	7	8	9	10
NP Peak (%)	2.1%	0.8%	1.2%	0.6%	0.8%	1.3%	1.1%	0.6%	-0.2%	0.2%
Other Peak (%)	-4.5%	-1.9%	3.5%	11.6%	19.5%	24.3%	30.0%	36.1%	40.8%	57.8%
Island Peak (%)	0.3%	0.1%	1.6%	2.9%	4.7%	6.1%	7.1%	7.8%	7.9%	11.1%

Table 7 shows that the entire interconnected Island peak forecast deviation can be associated with the high other peak demand forecast (rural, transmission & industrial).

Table 7: Peak Forecast Accuracy Measured in MW of Deviation from Actual Load

Years of History	1	2	3	4	5	6	7	8	9	10
NP Peak (MW)	22	9	14	8	10	15	13	7	-2	3
Other Peak (MW)	-18	-8	9	37	63	78	96	113	125	166
Island Peak (MW)	4	0	24	44	73	93	109	120	122	169

2.1.4 Summary

Regression models for the domestic sector are well founded and produce reasonable results. The 2012 Interconnected Island option increased domestic load by 326 GWh by 2029. MHI considers the increase reasonable and an improvement over the 2010 Load Forecast because the latest forecast is based on more current information for the number of customers, the weather-adjusted average use and the marginal electricity price, and higher economic forecasts for personal disposable income and population.

Regression models for the general service sector are well founded and produce extremely good results. The 2012 Interconnected Island option decreased general service load by 156 GWh by 2029 due to lower levels of growth for commercial business investment. MHI considers the lower forecast for commercial business investment conservative, thus producing a conservative forecast for the general service sector.

The customer-specific methodology used to prepare the industrial forecast is reasonable. If the Corner Brook mill remains in operation, the 2012 Interconnected Island option forecast should perform well over the next 5 to 10 years. In the longer term, the potential for new industrial loads would increase the likelihood of under-predicting future industrial energy requirements. If the Corner Brook mill closes, the 2012 Interconnected Island option forecast will over-predict energy requirements in the next 5 to 10 years. In the longer term, the Corner Brook mill load could be replaced by new potential industrial loads. The 2012 industrial forecast does not include any potential increase for new industrial customers after the expansion to Vale is completed. The industrial forecast should contain some allocation for potential future industrial loads.

The total Island energy and peak requirements have been over-predicted as a result of pulp and paper closures that were not accounted for in the industrial forecast. Otherwise, the total Island energy and peak forecasts have performed extremely well. The primary concern is that the total Island energy and peak forecasts over the extrapolation period are too low. The extrapolated energy forecast is only 44% of the load expected over the next 20 years. The extrapolated peak forecast is only 48% of the load expected over the next 20 years. These reductions in future growth are significant and may be overly conservative.

MHI finds that the Interconnected Island Load Forecast is sufficiently well founded and supported to be used as an input into the Decision Gate 3 process.

Figure 6: Newfoundland and Labrador Generation and Transmission System Map

2.2 AC Integration Studies

The ac system integration studies made available by Nalcor to MHI for the Decision Gate 2 review were for a different project definition. The ac integration studies reviewed as part of the Decision Gate 3 analysis use the latest project definition with generation at the Muskrat Falls Generating Station using a point-to-point HVdc transmission system (Labrador-Island HVdc Link) with the inverter station at Soldiers Pond. For Decision Gate 2, there was insufficient information provided to form an opinion on the suitability of the ac system integration studies for the project, however, with the documents provided to MHI as part of the Decision Gate 3 review, this step has now been completed.

A total of six studies were provided, and comprise the ac integration studies for Muskrat Falls Generating Station (CE13 through to CE19). These studies are reviewed in detail in Sections 2.2.1 through to 2.2.6, and in Section 2.2.9.

2.2.1 Construction Power Study

The construction power study examines options to supply a maximum load of 12 MW, which is expected to be reached in 2015, at the Muskrat Falls construction site in Labrador. The SNC Lavalin study[4] recommended the following:

- Replace the two existing 25/33/42 MVA 230/138 kV transformers at Churchill Falls with a larger 125 MVA bank that has an on-load tap changer with a tap range of +5% to -15%. The two existing transformers and the gas turbine at Happy Valley are expected to remain connected for back-up supply during the construction period to cover for failure of this new transformer.
- Install a temporary 6-km 25 kV transmission line to connect the construction power site to the Muskrat Falls tap station. An additional 10-km 25 kV transmission line will be constructed to connect the construction site to the camp site.
- Use direct line to line motor starters for the large motors connected at the construction power site.
- Install six 3.6 MVAr capacitor banks at the Muskrat Falls tap station on the 25 kV bus. Each capacitor bank is equipped with a 0.1-mH series reactor.
- Install a new 30/40/50 MVA 138/25 kV transformer at the Muskrat Falls tap station. The size and impedance need to be checked to ensure motors at the construction power site will successfully start. The contractor is expected to supply a 25/0.6 kV transformer.

[4] CE14, SNC Lavalin, "Construction Power System Study", April 16, 2012

The impedance and size of this transformer also need to be checked to ensure that the motors will successfully start.

The construction power supply study meets good utility practice. The above plan is robust and can supply up to 15 MW of peak load while meeting voltage criteria.

The original estimate of 6 MW used in 2010 was an old estimate calculated by Hatch Consultants in the early 1980s that did not include detailed engineering. Nalcor has good confidence in the 12 MW estimate as it was calculated by SNC Lavalin using recent information and detailed engineering calculations.

A 600 hp motor was considered to be the largest size that might be used at the construction site. Starting this motor resulted in a 4% voltage drop at the point of common coupling and 20% at the 600 V motor bus. This was considered acceptable in the report. Depending on the actual construction power motor load, such as larger motors, larger starting current, and frequent starts, there could be issues with voltage flicker or with motors tripping depending on their protection settings. Nalcor has indicated that the load estimate is mature including the number of large motors. The two 600 hp motors will at most start one or two times per day. The contractor will be made aware of the network limitations.

Only one 138/25 kV supply transformer is being proposed. In discussions with Nalcor, MHI indicated that it would be good utility practice to install two banks to ensure a reliable supply for the duration of the construction period. These two supply transformers should have staggered in-service dates to eliminate common mode failures during transport and installation. Nalcor indicated that a spare 138/25 kV transformer already exists at Happy Valley. This 28 MVA transformer has been a cold standby transformer at Happy Valley for the past twenty-five years. This transformer will be fully tested prior to the in-service date of the construction power substation and will be moved to Muskrat Falls if a failure occurs. In addition, two 2 MW diesel generators will be on-site for emergency power. ***Nalcor's construction power contingency plan is reasonable.***

The recommended capacitor bank size of 3.6 MVAr results in a 2.7% voltage change assuming maximum fault level. This voltage change is at the borderline of flicker visibility. If this were a permanent installation, normal utility practice would be to consider sizing the banks to avoid voltage flicker based on the minimum fault level. Adding a second transformer bank to improve supply reliability will help to reduce voltage flicker and will lower the net impedance, which will improve the motor starting performance. Nalcor indicated preference to not move the bank unless absolutely necessary to minimize risk and cost. The long term plan is to use the transformer at Happy Valley. Customer loads connected to the 138 kV network are not sensitive to voltage flicker.

If there are sources of harmonics on the 138 kV network, then the series impedance of the 138/25 kV transformer and capacitor banks should be sized to avoid a characteristic harmonic; especially the fifth harmonic. Transformer saturation due to elevated voltage levels is one common source of fifth harmonic. Nalcor indicated no known sources of harmonics and system voltages were typically less than 1.0 pu, which generally means the transformers are not saturated and not supplying fifth harmonic current.

2.2.2 Stability Studies

The stability studies in the SNC Lavalin report[5] examined the impact of the 900 MW Labrador-Island Link HVdc system and the 500 MW Maritime Link on Newfoundland primarily, as well as the ac network between Churchill Falls and Muskrat Falls in Labrador. The Labrador-Island Link HVdc system is expected to be in service on July 1, 2017 and first power is expected at Muskrat Falls in October 2017 with each subsequent unit coming online every two months.

Simple equivalents were used to represent the Nova Scotia and Quebec networks. Several load and generation assumptions were studied for the in-service year of 2017 and one additional case representing peak load in 2041. Year 2041 corresponds to the termination date of the Churchill Falls contract with Hydro Quebec.

The four-unit (4x206 MW, 0.9 pf) Muskrat Falls generation case was examined as Nalcor indicated this is the base plan that has been selected. Also, part of the 300 MW recall option from Churchill Falls is available to be used to supply Newfoundland load with a 100% capacity factor. As a result, the availability of generation at the rectifier of the Labrador-Island Link HVdc system is very high. Availability is only limited by the availability of the Labrador Island Link HVdc system. Currently, this surplus generation (265 MW) is wheeled through Quebec to New Brunswick but can be curtailed as required.

Contingencies examined included permanent dc pole faults, temporary bipole faults and three-phase normal clearing ac transmission faults. The selection of faults generally conforms to NERC category B or n-1 disturbances.

It was recommended in the study to:

- Install line-commutated HVdc converters for the Labrador-Island Link HVdc system. The link should be designed with a 10-minute, 200% overload rating, and 150% continuous overload rating while in monopolar operation.

[5] CE19, SNC Lavalin Inc., "Stability Studies", March 6, 2012

- Install three 150 MVAr high-inertia synchronous condensers at Soldiers Pond. Two units would always be connected, with the third used as a cold spare to save on losses and maintenance.
- Install voltage source converters for the Maritime Link. Consideration should be given to terminate the converter station in Bay d'Espoir instead of Bottom Brook. This avoids the need to add ac transmission reinforcements between Bottom Brook and Bay d'Espoir and also avoids the need for a fourth 150 MVAr synchronous condenser at Soldiers Pond.
- Evaluate settings of under-frequency relays to ensure proper coordination, such as avoiding operation for high rate of change of frequency if not required.
- Reduce the Maritime link HVdc transfer to 0 MW for outages of the Labrador-Island Link HVdc system or 230 kV ac network near Bottom Brook.

Given the simple equivalents used for Nova Scotia and Quebec, there may be issues in these networks that have not been identified. For example, if Churchill Falls and Muskrat Falls are both operating at maximum nameplate, one must determine whether the Quebec network absorb the total generation following a permanent bipole block on the Labrador-Island Link HVdc system. There may need to be a generator cross-tripping scheme installed at Muskrat Falls or additional transmission reinforcements installed. Muskrat Falls may need a dual input power system stabilizer to operate securely while connected to the Quebec network or when islanded. In discussions with Nalcor it became clear additional studies have been done by Quebec and Nova Scotia but they were not available for review. For the Quebec system, there is no additional transmission capacity available in its network for a long-term firm power sale. Approximately $3 billion in upgrades would be needed to interconnect Muskrat Falls in parallel with Churchill Falls onto the Quebec grid. Short-term power fluctuations (±1000 MW) are permitted by Hydro Quebec as they do not impact Quebec's system frequency. This helped Nalcor decide to limit the size of the Labrador-Island Link HVdc system to 900 MW. Automatic generation control will be used to quickly control generation in Labrador to maintain the area control error near zero and eliminate the concern with transmission congestion in Quebec. Protection and control addition to manage power on the collector system are not anticipated to impact the CPW analysis.

The stability study assumed the Maritime Link could be reduced to zero MW very quickly if a disturbance in Newfoundland occurred. There could be voltage issues in Nova Scotia that would prevent such a fast ramp rate, which would require mitigation. Nalcor indicated Nova Scotia was studying the impacts of the Maritime Link on its network closely and would be determining import/export and rate of change limits. It was not clear what type of power sale might be considered for the Maritime Link in terms of magnitude, duration, and level of firmness. A memorandum of understanding was signed between Nalcor and Emera Inc. on

November 18, 2010 with agreements signed July 30, 2012. For the purposes of the MHI Decision Gate 3 review, the Maritime Link is out of scope for this analysis.

There is fair amount of uncertainty as to the location of the Maritime Link converter station and technology. Both line-commutated converters with static var compensators and voltage source converters could work. Nalcor is showing some preference for the original Bottom Brook location with voltage source converters and appropriate ac transmission upgrades. However, the final topology is yet to be decided.

The largest contingency is currently loss of the entire Holyrood plant for a nearby three-phase fault. After 2021, it is proposed to retire Holyrood and only operate the plant as a synchronous condenser. If these synchronous condensers do not remain connected for the worst case disturbance there are concerns the Labrador-Island Link HVdc system may also trip due to the network being too weak. Nalcor indicated the Holyrood generators were tripping off due to the plant auxiliaries not having sufficient low voltage ride-through. With retirement of the boilers, Nalcor does not expect there to be any remaining plant auxiliaries that would trip the synchronous condensers due to low voltage.

Nalcor provided information on generator under-frequency protection settings. The Holyrood units have a setting of 58.8 Hz and 45 seconds. For the cases simulated, the worst case was roughly 58.8 Hz for a temporary bipole block. There are no concerns with loss of additional generation with the Labrador-Island Link HVdc system as the minimum frequency is planned to remain above the first block of load shed trip point of 58.8 Hz with 0.1 second pickup time.

There could be advantages to specifying some overload capability while in bipolar operation to cater for large generator outages on the Newfoundland network. Nalcor will be including this question in the converter request for proposal. They agree that having access to additional spinning reserves from Labrador will have operational advantages. There are concerns with having the nameplate of the link larger than 900 MW. Also, the proposed reactive power support may be insufficient unless the new 150 MVAr cold standby spare is made a hot standby.

Nalcor indicated they had upgraded some of their generating units with high-speed exciters that had power system stabilizers, and had plans to modernize the remaining units. However, all of the power system stabilizers on Newfoundland are turned off. The stability studies did not indicate any issues with poor damping of power oscillations and Nalcor indicated no issues have been reported during real time operations. It is recommended that a small signal stability study be undertaken to confirm that power system stabilizers are not needed or to determine the preferred settings for the power system stabilizers.

Permanent Bipole Block

A permanent bipole fault is a low probability event; however, it is a credible event. This is a major difference between the Isolated Island option and Interconnected Island options.

From an n-1 perspective, the two options are different in terms of the impact from loss of the largest generator. No load-shedding is planned to occur following the loss of the largest generator in the Interconnected Island option. The Isolated Island option is a continuation of the status quo, which permits under-frequency load shed to occur. The Isolated Island option would require significant investment to match the improved reliability of the Interconnected Island option. Additional inertia would be required as well as additional generation to supply spinning reserves. A minimum of three 150 MVAr high-inertia synchronous condensers and a 170 MW combustion turbine would be required to make the two options perform similarly. This would need to be confirmed by additional stability studies.

From an n-2 perspective, the permanent bipole block results in a potential loss of up to 900 MW at the rectifier for the Interconnected Island option. The Isolated Island option would have an n-2 loss of from 340 MW (loss of two generators) to 520 MW (loss of the Holyrood plant). There is no planning criteria on Newfoundland that require prevention of instability for a permanent bipole fault. However, there is a requirement to minimize under-frequency load-shedding. It may be possible to separate Newfoundland into separate zones following a permanent bipole block to minimize the amount of load shed as well as to improve system restoration times. Nalcor indicated during the meeting that it was already investigating this as a potential mitigating measure.

In addition, the synchronous condensers recommended to be installed at Soldiers Pond to strengthen the inverter bus could be combustion turbines. The decision gate 2 generation plan assumes a 170 MW combustion turbine is needed in 2037. This unit could be advanced, installed at Soldiers Pond and operated as a synchronous condenser until needed. In the event of a permanent bipole loss, this unit could be utilized to supply load. The Maritime Link, if it was built and generation was available in Nova Scotia, could be used to supply load in Newfoundland if a permanent bipole block occurred. Having 300 to 500 MW of import capability from Nova Scotia would eliminate the need to install additional combustion turbines in Newfoundland to cover for a permanent bipole outage. During the decision gate 2 review, Nalcor had estimated the potential unserved energy for a two-week bipole outage both with and without the Maritime Link and with varying levels of additional combustion turbines in Newfoundland[6]. Nalcor found, for example, the Maritime Link with 300 MW of import capability would completely cover a bipole loss until 2022 and an additional 170 MW

[6] Exhibit 106, Nalcor, "Labrador-Island HVdc Link and Island Interconnected System Reliability", October 30, 2011

combustion turbine would cover the loss until 2037. These additional combustion turbines are not factored into the Interconnected Island option base case.

If the Maritime Link were to be cancelled, it would be prudent to re-evaluate the need for additional combustion turbines to partially or totally cover the permanent loss of the Labrador-Island Link HVdc system. However, the additional cost should not be added to the project at this time because covering the loss is beyond the current planning criteria in Newfoundland.

2.2.3 Load Flow and Short-Circuit Studies

Short-circuit and load flow studies were reviewed by MHI as part of the Decision Gate 3 review[7]. ***Short circuit and load flow studies were performed according to good utility practice. No equipment concerns were noted in this study.***

From the study it was unclear whether the 138 kV and 69 kV networks are radial or networked. These networks were ignored in the study and assumed radial. Higher loading on the 230 kV network could impact underlying low voltage networks. In meetings with Nalcor, they indicated that there are three 138 kV transmission lines that are networked as follows:

- Holyrood to Western Avalon
- Sunnyside to Stony Brook
- Stony Brook to Deer Lake

These were studied recently by Nalcor as part of the Decision Gate 2 review and either no issues were noted or no issues were resulting from the Isolated Island or Interconnected Island options[8]. Local issues were noted in this document for the Sunnyside to Stony Brook circuit but plans are in place to address these. There are two 230-66 kV transformers that form a meshed circuit in St. John's. No issues were noted on this circuit. In general, slow clearing faults on the 66 kV network have impacted the Holyrood plant. Six-cycle clearing has been implemented (three-cycle breaker, 1-cycle relay time, 1-cycle transfer trip and 1-cycle margin), which corrected the problem. 66 kV fault clearing was included in the contingency list and no HVdc commutation failure issues were noted.

There was no clear criteria identified by Nalcor for setting up spinning reserve requirements in the power flow cases. The 2041 case is set up without generation reserves, which means any generator outage results in load-shedding. The 2041 case should have had

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[7] CE17, SNC Lavalin, "Load Flow and Short-Circuit Studies, April 5, 2012

[8] Exhibit 24, Nalcor, "Island Transmission Outlook", Decision Gate 2 review, December 2010.

an extra 170 MW generator added as per the generation plan (in-service date 2037). Nalcor indicated that it does not currently have a spinning reserve criterion. For loss of the largest generator today, it relies on under-frequency load-shedding to prevent a widespread blackout. Under-frequency load shed is being used instead of spinning reserves. Nalcor provided a guideline for Unit Maximum Loading that indicates the secure limit for the maximum plant as a function of system load. The guideline ensures that sufficient load is able to be dropped to prevent the frequency from falling below 58 Hz. Nalcor has made some investigations into adding spinning reserve to match the size of the largest unit loss and doubling the inertia of all existing units. This approach does not eliminate under-frequency load shed. The Interconnected Island option, with the addition of high-inertia synchronous condensers at Soldiers Pond, is able to improve this situation and avoid load-shedding for a single contingency.

From the report, it was unclear what the Soldiers Pond synchronous condenser assumption was for the minimum fault level case in determination of the equivalent short circuit ration (ESCR). Nalcor clarified in the meeting that the minimum ESCR was calculated with two 150 MVAr synchronous condensers at Holyrood and none at Soldiers Pond.

If both the Maritime Link and Island Link converters are planned to import simultaneously, then it is recommended to use the multi-infeed ESCR method documented by CIGRE (Council on Large Electric Systems)[9]. In discussions with Nalcor, the Maritime Link planned for import when the Labrador-Island HVdc Link was out of service.

2.2.4 HVdc System Modes of Operation and Control Strategies Study

The HVdc System Modes of Operation and Control Strategies Study[10] conformed to good utility practice and properly identified the different configuration modes and operational modes.

Some items of technical concern were raised during the meeting with Nalcor. One item was that a pole block while in the loop power flow control mode could result in over-voltages requiring filter tripping[11]. This contingency was not tested in the stability[12] or power flow[13] studies. MHI noted to Nalcor that it is recommended to simulate tripping of either pole and confirm the over-voltage impacts. Other issues raised were whether there a need to utilize overload capability while in this mode to increase the speed of ice melting, and whether there

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[9] Brett Davies et al., "Systems with Multiple DC Infeed", CIGRE Working Group B4.41, Publication 364, December 2008.
[10] CE16, SNC Lavalin, "HVdc System Modes of Operation and Control Strategies Study", May 3, 2012.
[11] CE16, SNC Lavalin, "HVdc System Modes of Operation and Control Strategies Study", April 17, 2012, pg 15.
[12] CE19, SNC Lavalin, "Stability Studies", March 6, 2012.
[13] CE17, SNC Lavalin, "Load Flow and Short-Circuit Studies", April 5, 2012

concern if the import pole trips. The loop power flow control mode should automatically switch off if a pole trip occurs, but the control strategy document was not clear on this issue. Nalcor indicated that it will clarify this item during HVdc design studies. There should be no impact on cost. The worst case would be the addition of a filter overvoltage relay.

2.2.5 Harmonic Impedance Studies

The harmonic impedance of the ac network was calculated at Muskrat falls and at Soldiers Pond. This study[14] was conducted according to good utility practice.

The harmonic impedance study should consider operation with three 150 MVAr synchronous condensers as this may occur for high loads or outages of transmission lines near Soldiers Pond. Nalcor noted this recommendation and will recalculate the harmonic sectors for the Labrador-Island Link Request for Proposal.

A list of shunt reactors and capacitors near the converter station should be compiled to ensure appropriate sensitivity cases were completed. Nalcor provided a list of capacitors and reactors up to four buses away and confirmed that sufficient variations were included in the harmonic study.

2.2.6 Reactive Power Studies

This SNC Lavalin report for Nalcor determined the steady-state reactive power capabilities of the ac network over the feasible operating voltage range of the HVdc converters[15]. Potential voltage instability was identified at Bottom Brook, which justifies the need for a static var compensator or voltage source converter at this location. ***The report is written following on good utility practice.***

The inverter could be thought of as a generator interconnection and the inverter could be required to supply reactive power over the range 0.95 leading to 0.95 lagging. Alternatively the link could be designed to be unity power factor or self-sufficient in reactive power. Nalcor does not have a published grid code that defines the reactive power or voltage control requirements for new generator interconnections. Requirements are determined on a case-by-case basis depending on the size and location of the generator. For Muskrat Falls, no reactive power exchange was assumed available from Churchill Falls. With one unit out at Muskrat Falls, assuming filters were in-service supplying 25% of the reactive power of the rectifier, the remaining Muskrat Falls units were required to hold the 315 kV voltage at 1.02 pu. This

[14] CE15, SNC Lavalin, "Harmonic Impedance Studies", March 6, 2012.
[15] CE18, SNC Lavalin, "Reactive Power Studies", December 7, 2011.

required the units to be rated at 0.9 pf. At the inverter, assuming the filters provide 25% reactive support, the synchronous condensers are required to hold the voltage to 1.02 pu at maximum loading. This methodology is reasonable.

2.2.7 Preliminary Transmission System Analysis – Muskrat Falls to Churchill Falls Transmission Voltage

The Preliminary Transmission System Analysis report examines the voltage options to interconnect the Muskrat Falls generating station to Churchill Falls[16]. Four single-conductor 230 kV lines, three two-conductor 230-kV lines, and two two-conductor 315 kV or 345 kV lines were compared. Two 345 kV lines with 45 MVAr shunt reactors located at both sending and receiving ends were recommended. The 345 kV lines could also be built to 315 kV. **This report is in accordance with good utility practice and makes sound recommendations.**

According to Nalcor, the voltage level was adjusted to 315 kV after the report was released to allow for the potential to expand the transmission network into Quebec in the future if desired. In addition, the 45 MVar shunt reactors were removed in favor of using on-load tap changer capability and the reactive power capability of the Churchill Falls and Muskrat Falls generating stations.

MHI noted one concern; Nalcor intends to implement single-pole trip and reclose on the new 315 kV transmission lines between Churchill Falls and Muskrat Falls. High voltage long lines greater than 300 kV quite often employ four-pole reactors to help improve the probability of extinguishing the secondary arc current, thus ensuring a successful reclose[17]. Without these reactors, a longer pole open dead time may be required or single-pole trip and reclose may need to be disabled. For the transfer levels studied, single-pole trip and reclose was not demonstrated as necessary to maintain stability. Nalcor noted the concern and will investigate the feasibility of single-pole trip and reclose with and without four-pole reactors. There is some minimal risk that one or two four-pole reactors will need to be added to each of the 315 kV lines.

2.2.8 Island Transmission Outlook

This Island Transmission Outlook report provided as part of the Decision Gate 2 review examines the ability of the current transmission system to meet the Newfoundland planning

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[16] Exhibit 59, Nalcor, "Preliminary Transmission System Analysis – Muskrat Falls to Churchill Falls Transmission Voltage", November 2010.

[17] IEEE Committee Report "Single Phase Tripping and Auto Reclosing of transmission Lines", pp. 185, Jan. 1992. In table III of the IEEE Committee report, they note for 345 kV lines greater than 140 miles, additional measures must be undertaken to reduce the secondary arc current.

criteria and provides an outlook for the requirements for system additions in the five to ten year frame[18]. The Bay d'Espoir east transmission network is noted as requiring an additional 230 kV circuit. The circuit is needed for power system stability reasons if a future HVdc tie is constructed or if the Island of Newfoundland remains isolated. When the island remains isolated, additional thermal capability is required to supply load in the Avalon Peninsula from new generation from Portland Creek, Island Pond and Round Pond. This report expected the line to be added to the capital plan in 2011 with construction expected to be complete by 2016.

2.2.9 Labrador-Island HVdc Link and Island Interconnected System Reliability

The Labrador-Island HVdc Link and Island Interconnected System Reliability study compares the reliability of the Island Link HVdc to the existing system reliability[19]. The impact of the Maritime link is quantified and the design criterion of the HVdc transmission line is discussed.

With the Island link transmission line designed for a 1:50 return period, assuming a 14 day restoration time to fix transmission outages results in a maximum 1% maximum annual unserved energy. The report characterized the 1:50 return period being for ice-loading only but Nalcor clarified that this was for both wind and ice-loading.

This study meets good utility practice. A more accurate calculation would have required the use a probabilistic assessment tool as recommended in the Decision Gate 2 review. However, the purpose of the study was to provide a simple quantitative comparison between the status quo and potential futures in terms of the impacts of major outages due to ice storms. The report fulfills this purpose.

2.2.10 Summary

The AC Integration Studies that were reviewed follow good utility practice and are adequate to define the minimum transmission facilities needed to:

- Supply the expected maximum construction power load of 12 MW at Muskrat Falls,
- Interconnect four 206 MW Generating units at Muskrat Falls, and
- Deliver the output from approximately 900 MW of generation in Labrador to Newfoundland load.

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[18] Exhibit 24, Nalcor, "Island Transmission Outlook", December 2010.
[19] CE13, SNC Lavalin, "Reliability & Availability Assessment of the HVdc Island Link", April 10, 2012.

There is a remote possibility that up to four 45 MVAr 315 kV four-pole shunt reactors may be needed to permit successful single pole tripping and reclosing on the new 315 kV lines between Churchill Falls and Muskrat Falls.

For a fair comparison, the Isolated Island option should be designed to not rely solely on underfrequency load shed following loss of the largest generator. Additional studies would be needed to confirm but it is estimated that three high-inertia 150 MVar synchronous condensers would be needed at or near Soldiers Pond as well as a 170 MW Combustion Turbine for spinning reserves. However, the costs for these additions should not be added to the Isolated Island base case until a supporting engineering study is performed.

MHI recommends:

Harmonic impedance sector calculations includes cases where all three 150 MVAr synchronous condensers at Soldiers Pond are in operation for both system intact conditions and 230 kV ac transmission line prior outages.

Further work should be conducted to design a special protection scheme that will balance available generation with load following a permanent bipole outage on the Labrador Island HVdc Link. The 230 kV transmission system on the Island can be configured to trip specific transmission lines with the use of an appropriate underfrequency or rate of change of frequency relay, or direct tripping signal from the HVdc converter station at Soldiers Pond to balance load with generation.

A power system stabilizer study should be conducted to determine appropriate settings for the Muskrat Falls Generating Station as well as for generators and synchronous condensers in Newfoundland.

2.3 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 Decision Gate 3 review of the two options. This review was carried out by HVdc experts on staff at MHI through meetings with Nalcor and reviews of a number of confidential documents provided by Nalcor. Many of these documents were not available during the Decision Gate 2 review, thus are examined here.

2.3.1 HVdc Configurations

The system single line diagrams were reviewed for the HVdc converter stations (dc yard) at both terminals with electrode sites, the new 315 kV ac switching station at Muskrat Falls, the ac system extension at Churchill Fall 735 kV / 315 kV switching station, and the new 230 kV ac station at Soldiers Pond [20],[21],[22],[23],[24],[25],[26]. The dc and ac yard layouts as shown in the single line diagrams follow good utility practice and the identified system upgrades are well supported by the study reports described in AC Integration Study Review Sections 2.2.2, 2.2.4, and 2.2.6. The planned transmission outlet facilities at Muskrat Fall and Soldiers Pond are adequate for the proposed HVdc Link rating. Three 150 MVAr high-inertia synchronous condensers are planned at the Soldiers Pond 230 kV ac station to strengthen the system and assist in voltage and frequency control.

2.3.2 Reliability and Availability Assessment

The Reliability & Availability Assessment report presents the results of the reliability and availability analysis carried out to determine the expected reliability performance of the proposed Labrador-Island Link HVdc system[27]. The Reliability and Availability performance indices for key system components including the converter stations, the HVdc transmission line from Muskrat Falls to Soldiers Pond, the submarine cables, the electrode lines and the composite reliability performance of the complete Labrador-Island Link HVdc system were derived and considered to be in the reliability performance range of the HVdc schemes in-operation today. The recommendations on provision of spare equipment such as converter transformers and smoothing reactors follow good utility practice.

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[20] CE38, SNC Lavalin, "Churchill Falls Location Drawing Extension of 735 kV New 315 kV Substation", 2012.
[21] CE39, SNC Lavalin, "Soldiers Pond Station Location Plan 230 kV Switchyard and Converter Substation", 2011.
[22] CE40, SNC Lavalin, "Muskrat Falls Station Location Plan 315-138kV Switchyard and Converter Station", 2011.
[23] CE41, SNC Lavalin, "230kV Soldiers Pond Switchyard Single Line Diagram", 2011.
[24] CE42, SNC Lavalin, "735-315 CF Switchyard Extension Single Line Diagram", 2011.
[25] CE43, SNC Lavalin, "Muskrat Falls HVDC Transmission System Overall Single Line Diagram", 2011
[26] CE44, SNC Lavalin, "315-138 kV Muskrat Falls Switchyard Single Line Diagram", 2011
[27] CE13, Nalcor, "Reliability and Availability Assessment of the HVdc Island Link", April 2012.

The study determined that the repair time of the HVdc transmission line failure has significant impact on the availability of the island HVdc link. Line design enhancement such as anti-cascading tower and a good emergency response plan is recommended for further evaluation in the detailed design stage. Special care shall also be paid to the electrode line reliability, such as insulation coordination and arc extinguishing capability, due to its unique overload operation mode under pole outages and extreme long distance.

The electrode line and electrode section is dealt with in a limited fashion and requires more attention as this element is critical for the overload capability during mono-polar operation. Because of the long-distance of the electrode line on the Labrador side and the fact that during normal operation there is virtually no voltage or current (just the bipolar unbalance current), detecting the soundness of the electrode line is very difficult. Investigation into fault detection and locating systems such as Pulse Echo systems for the electrode lines is recommended by MHI. Addition of this item would not material impact the CPW of the overall project.

2.3.3 HVdc Master Schedule

The HVdc system master scheduling documents outline the schedules for procurement, installation, and commissioning of the HVdc converter stations and related components[28],[29]. The project schedules and execution times including engineering, procurement, constructions are comparable to similar HVdc projects.

2.3.4 HVdc Cost Estimates

Master cost estimates provided by Nalcor for the HVdc converter stations, ac switchyards, synchronous condensers, and electrode sites were examined as part of the Decision Gate 3 review[30].

The capital cost estimate includes the system upgrades at the HVdc converter stations (both ac and dc yards) and the island system enhancement, such as synchronous condenser conversions of Holyrood Thermal Generating Station as well as replacement of high voltage breakers. Two shoreline electrodes and associated electrode lines are included in this estimate. The first electrode line from the Muskrat Falls converter station has a significant length of about 400 km and most electrode line will be mounted on the same HVdc overhead tower. The second electrode line will emanate from Soldiers Pond approximately 10 km to the electrode site near Dowden's Point in Conception Bay. MHI finds that the estimates are

[28] CE05, Nalcor, "LCP HVdc Project Control Schedule", April 2012.
[29] CE32, Nalcor, "Nalcor Energy – Lower Churchill Project MS Project", June 2012
[30] CE26, Nalcor, "LCP Phase 1 DG3 Final Estimate Excl Maritime Link Project", 2012.

reasonable as inputs to the Decision Gate 3 screening process and CPW analysis. The estimates on synchronous condensers are, however, low but are within the bands of cost estimate variability.

The capability of maintaining full HVdc power rating while losing one ac filter branch element was verbally indicated by the proponent but this information was not included in the Short Form Specification sent to the suppliers so it cannot be determined if this is included in the cost or not. For example adding the third ac filter bank for 3 X 50% ac filter redundancy could add $20 to 25 million to the base cost.

System study Reports

The scope of work in the study reports included power flow and short circuit analysis, harmonic study, reactive power study, transient stability analysis, HVdc control strategy and HVdc modes of operations.

The Load Flow and Short Circuit Studies[31] and the Reactive Power Studies[32] have determined the short circuit levels (fault levels) at converter stations, power dispatches under various load flow scenarios, and reactive power requirements for the proposed Labrador-Island Link HVdc system. The proposed system upgrades at Muskrat Falls and Soldiers Pond are adequate for the HVdc operating modes considered and the overload requirement. The ESCR requirements are met at both converter terminals with the proposed system upgrades and the HVdc system is expected to provide acceptable performance based on industry experience. The harmonic impedance study[33] provides preliminary information for the filter designs with no adverse low-frequency system resonance identified.

Detailed HVdc performance under various contingencies is evaluated in the stability study report[34]. It is worthy to note that Nalcor disclosed in a meeting that one of the main system development criteria is to achieve the same or better reliability than today's system considering its unique island electrical system configuration. The study results demonstrated the acceptable HVdc system responses of the proposed HVdc link following various ac and dc contingencies. Two 150 MVar high-inertia synchronous condensers plus one spare are required at the Soldiers Pond 230 kV ac station based on system stability requirements.

The HVdc configurations, operation modes, control hierarchy and strategies, communication requirements were presented in the study report[35]. The basic philosophy

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[31] CE17, SNC Lavalin, "Load Flow and Short Circuit Studies", April 5, 2012.
[32] CE18, SNC Lavalin, "Reactive Power Studies", December 7, 2011.
[33] CE15, SNC Lavalin, "Harmonic Impedance Studies", March 6, 2012.
[34] CE19, SNC Lavalin, "Stability Studies", March 6, 2012.
[35] CE16, SNC Lavalin, "HVdc System Modes of Operation and Control Strategies Study", April 17, 2012.

outlined in this report conforms to good industry practice. The report stated that the final implementation requirements were to be developed and presented as part of the Technical Specifications. During islanded operation, the impact of frequency excursions on control strategy will need to be evaluated. However, no implications on the additional costs are expected.

Short Form Technical Specification

Lower Churchill Project Short Form Technical Specification datedOctober 13, 2011[36] was reviewed as part of the Decision Gate 3 review by MHI. This document was provided to three suppliers to obtain cost estimates for the HVdc converter stations: ABB, Siemens and Alstom Grid. The Specification forms the basis for the costs estimates received from the suppliers. The typical practice was to discard the lowest estimate and average the two highest for budget preparation. This philosophy was carried forward in all cost estimates prepared for Decision Gate 3 where applicable. MHI also noted the following items:

- In Section 4.3.1 of the Short Form Technical Specification, the maximum short circuit faults appear low given the size of generators at the Muskrat Falls Generating Station and the three 150 MVar synchronous condensers at Soldiers Pond.
- In Section 4.3.3 of the Short Form Technical Specification, the last line states "Furthermore 3X150 MVAR synchronous condensers are planned to be installed, one of which will be off line." This position is not reasonable since a third unit is available. It would make sense to place it on line in case one synchronous condenser unit trips off.
- The creepage distance in Section 4.4 appears reasonable.
- Section 5, paragraph 3 of the Short Form Technical Specification states, "The Contractor shall provide sufficient ac filters to meet the normal filtering requirements." In meetings with Nalcor it was disclosed that the ac filters would be 100% redundant. No such requirement for redundancy was included on the Short Form Technical Specification.
- No Reliability, Availability and Maintainability (RAM) Criteria and Guarantees are specified in the document. The only mention of this is in Section 5.4, where "Reliability and availability shall be demonstrated during this period."
- There is no list of required studies included in the specification.

Given the above omissions, there is a possibility of additional costs, depending on what the suppliers assumed for the missing information. For example, adding the third ac filter

[36] CEXX, Nalcor, "Lower Churchill Project Short Form Technical Specification", October 13, 2011.

bank for three times 50% ac filter-redundancy could add $20 to 25 million to the base estimate. Given that Nalcor verbally indicated that they have used the two higher estimates of three submitted, and that they were both close to each other, indicates that this approach is reasonable for providing a budgetary cost estimate.

2.3.5 Summary

MHI through its review notes the following important points:

- The study determined that the repair time of the HVdc transmission line failure has significant impact on the availability of the Labrador-Island Link HVdc system. Line design enhancement such as anti-cascading tower and a good emergency response plan is recommended for further evaluation in the detailed design stage.
- The electrode line and electrode section of the Reliability & Availability Study analysis appeared minimal and requires more attention as the electrode is required for the reliable overload capability during mono-polar operation. Because of the long-distance of the electrode line on the Labrador side and the fact that during normal operation there is virtually no voltage or current (just unbalance current), this makes detecting the soundness of the electrode line very difficult. Investigation into fault detection and location systems such as Pulse Echo systems for the electrode lines is recommended. Addition of these detection systems is expected to have a minimal cost impact.
- In verbal discussion with Nalcor it was indicated that the ac filters would be 100% redundant. No such requirement was included on the Short Form Technical Specification. No Reliability, Availability and Maintainability (RAM) Criteria and Guarantees are specified in the document. The only mention is in Section 5.4 where "Reliability and availability shall be demonstrated during this period." There is no mention of security, safety and environmental requirements. A list of required studies was not included in the specification. The fact that type test older than normally five years must be repeated was not included in the specification. Given the above items there is a possibility of increased costs depending on what the suppliers assumed for the missing information. For example adding the third ac filter bank for three times 50% ac filter redundancy could add $20 to 25 million. Given that Nalcor verbally indicated that they have used the two higher estimates and they were both close to each other indicates that this approach is reasonable.
- The estimates on synchronous condensers appear low but costs have been provided by several manufacturers. The cost estimates are within the bands of cost estimate variability for an AACE Class 3 estimate range.

Overall the project as indicated by Nalcor both verbally and in documents provided appears reasonable. MHI has made some recommendations as outlined above that may provide improvements to the project.

The system upgrades identified in the single line diagrams for HVdc converter stations, ac switchyards, and electrodes are well supported by the study reports provided to MHI by Nalcor and are reasonable as inputs to the Decision Gate 3 CPW analysis.

2.4 HVdc Transmission Line, Electrodes and Collector System

The purpose of this section is to conduct a high level review of the high voltage dc (HVdc) lines, the electrode sites, and the high voltage ac (HVac) collector transmission system Nalcor proposed at Decision Gate 3 as compared to the configuration in place at Decision Gate 2.

Cost estimates, construction schedules, and the design methodology undertaken by Nalcor in preparation for Decision Gate 3 were examined and an assessment made of the reasonableness as inputs to a CPW analysis.

2.4.1 Schedule

Nalcor's proposed schedule for the HVdc and ac line designs, procurement, and construction were reviewed through a series of interviews with key Nalcor personnel. Only a high level schedule for the existing scope was provided in Nalcor's document "Project Schedule – Transmission."[37]

At this time, detailed design of the transmission line structures is under way, and testing of critical line structures scheduled later this year. Nalcor projected to extend detailed design right through to construction completion in the schedule. This is a prudent industry practice to support construction on large transmission projects with changing terrain necessitating field-specific design solutions.

Procurement activities have been staged to in the first quarter of 2012. MHI understands much work has been done to verify pricing and supply of the various transmission line materials pending official Decision Gate 3 project sanction. To date, a total of 21 material procurement management packages are being prepared to fulfill the transmission requirements. To maintain the project construction schedule as planned, the majority of material contracts for long lead-time items such as towers, insulators, and conductors should be awarded by the end of 2012 for a fall 2013 or early 2014 construction start.

The construction window for all high voltage transmission line construction activities for the project complex has been allocated approximately four years with clearing activities starting in the second quarter of 2012. MHI finds the schedule to be reasonable and achievable provided construction work and equipment access is possible during all four construction seasons.

[37] CE12, Nalcor, "Transmission Schedule", not dated.

2.4.2 Cost Estimate Evaluation

Nalcor did not provide MHI with access to the detailed cost elements, nor costing reports defining the Decision Gate 3 estimate and variance from the Decision Gate 2 estimate for the transmission facilities. However, totals are provided and overall the Decision Gate 3 estimate increased significantly from Decision Gate 2. The Decision Gate 2 estimates increased approximately 120% for the HVdc lines, and 45% for the HVac lines[38].

Nalcor described the methodology in preparing the Decision Gate 3 estimate and MHI considers that it adequately reflects the costs forecasted for the construction of the transmission lines.

The Decision Gate 3 estimate is based upon the following contributory factors:

- Costing from suppliers for detailed material breakdowns and known bulk quantities such as number of towers, insulators, and hardware
- Transmission contractor budgetary feedback based upon the proposed schedule and construction methodology and timelines
- Engineering concepts that are virtually complete, and scope changes tracked and identified[39]
- Labour unit costing assuming a negotiated master labour agreement, equipment and commodity rates are identified
- Productivity factors for labor, equipment, while factoring in seasonal impacts.

Comparing the Decision Gate 3 cost estimate evaluated on a cost-per-line-km basis with other similar projects under way in Canada, MHI finds the Muskrat Falls transmission line complex costs are at an acceptable level and accuracy for this stage of the estimate. The costs are within an AACE Class 3 estimate accuracy congruent to the requirements of Decision Gate 3.

2.4.3 Risk Assessment

Nalcor has identified the key areas of project risk in its project management strategy. At the current stage of project progress, the majority of major engineering decisions affecting transmission line design and construction as to project scope have been made and costs estimated for Decision Gate 3. Nalcor has displayed appropriate controls and signing

[38] CE31, Nalcor, " Nalcor Comparative Study & Cost Growth Since DG2", not dated
[39] CE25, Nalcor, "Basis of Design Document", not dated

authority managing scope changes with the Transmission Deviation Alerts and the Change Notice document MHI reviewed.

With the level of engineering complete to date and the tracking system in place, the probability of major scope changes to the design affecting cost and schedule is assessed as very low. At this stage minor route changes will not affect cost or schedule significantly.

Material costing has been calculated with estimated line quantities at current market values and as such is likely to only vary with the final tower optimization quantities. These variations should not be significant from the quantities currently estimated.

At this stage, the major risks to be addressed for the transmission line complex remain with contractor cost and labour availability. There are several other high-profile transmission line and generation projects in the design stage in Canada set for construction in the same time frames as Nalcor's Lower Churchill project. These, along with other natural resource projects could attract skilled labour away from this project and create an escalation factor for contractor labour.

Nalcor has identified these issues as the major risks and has identified a strategy to attract skilled labour back into the province through a master labour agreement, training, and other self-development programs. While these programs and compensation levels were not identified in detail, MHI is aware of the issue of contractor availability in a very competitive skilled labour market.

2.4.4 Assessment of Line Routes

MHI has reviewed the general route corridor provided in Google Earth format. The route corridor MHI reviewed is the publically available 2-km-wide corridor running from Muskrat Falls across the Strait of Belle Isle to the Soldiers Pond Converter Station[40]. The 60-metre-wide final transmission line alignment remains confidential to Nalcor until it receives final permitting, and completes its property acquisition and easement process. As the detailed routing alignment is not available, MHI's assessment will be limited to only the route suitability in the most general terms.

HVdc Transmission Line Route

The route selected for the HVdc line is reasonably optimal considering the primary criteria required for an efficient bulk point-to-point transmission line. The line has been designed to be as straight as possible between the source and load stations, minimizing angle locations

[40] CE-24 Lower Churchill Project –Asset Schematic by Project (Excluding Maritime Link)

where possible. The route navigates the more difficult areas of Labrador, by-passing the numerous large lakes, ponds, and swampy terrain with a minimal number of line angles. All water crossings appear achievable with minimal custom site designs typified as shown in Figure 7.

Figure 7: HVDC Transmission Line Route Water and Highway Crossing

The above figure shows a typical water crossing and the river crossing spans are achievable with the given design basis.

The route proceeds as directly as possible through the Long Range Mountain Ridge before it turns east heading through the Newfoundland Island to the Soldiers Pond Converter Station.

Portions of the route are adjacent to major roads such as the Trans-Canada and Trans-Labrador highways. This will help facilitate access to clearing, construction of the line, maintenance, and with planning an emergency response scenario. A review of the corridor displayed numerous access trails which enables fairly good access to the line in most seasons. MHI recommends that once the route is finalized, other access trails should be constructed for future use in emergencies or maintenance.

The route corridor through Labrador is finalized with the island portion of the corridor set for public input and approval. Nalcor has expressed confidence that final approval is forthcoming with minimal unforeseen changes to the routing. While MHI does not have access to information and cannot comment on local issues which may affect the final routing, the route appears to be well suited for its purpose.

AC Transmission Line Routing

The routing for the two 315 kVac lines connecting Churchill Falls to Muskrat falls essentially follows the corridor of existing 138 kV transmission line TL 240. The corridor is well established and will be widened to an appropriate width to contain the additional two lines. MHI reviewed the Google Earth transmission line corridor and does not foresee any difficulties with this planned corridor addition. Nalcor still needs to obtain appropriate approvals and easements.

Electrode Line Routing

Detailed routing for the small lengths of electrode line to the Labrador (the electrode line is to be carried on the HVdc towers) and Newfoundland Electrode sites were not made available for this review, and as such MHI cannot comment as to the appropriateness of the routing. These small lengths of electrode line have a small cost when compared to the overall project and thus would not have a material impact.

2.4.5 Structure Families

MHI reviewed Nalcor's proposed structure families for the new transmission lines in meetings with Nalcor's Principal Design Engineer and reviewed formal and informal printed documentation from design files. Final design drawings are neither complete nor available in an appropriate format for detailed review.

Nalcor's design philosophy used to determine the structure families for the ac and dc transmission lines follows an industry-accepted practice of apportioning out structures into "families" classified by their function along the transmission line. Structure families proposed in the designs include tangent suspension structures, various degrees of angle structures, heavy angle, and termination structures used to sectionalize the line.

The tangent suspension towers Nalcor has selected for both ac and dc systems are composed of guyed lattice steel mast-type structures modifiable by height extensions to maximize tower utilization in the rolling terrain common along the entire corridor. These types of structures are the best economical choice given the variety of geophysical soil conditions, terrain to be crossed, and remoteness of the route selected. Use of these structure types is common throughout the industry, and there are many other examples of these towers successfully installed throughout North America.

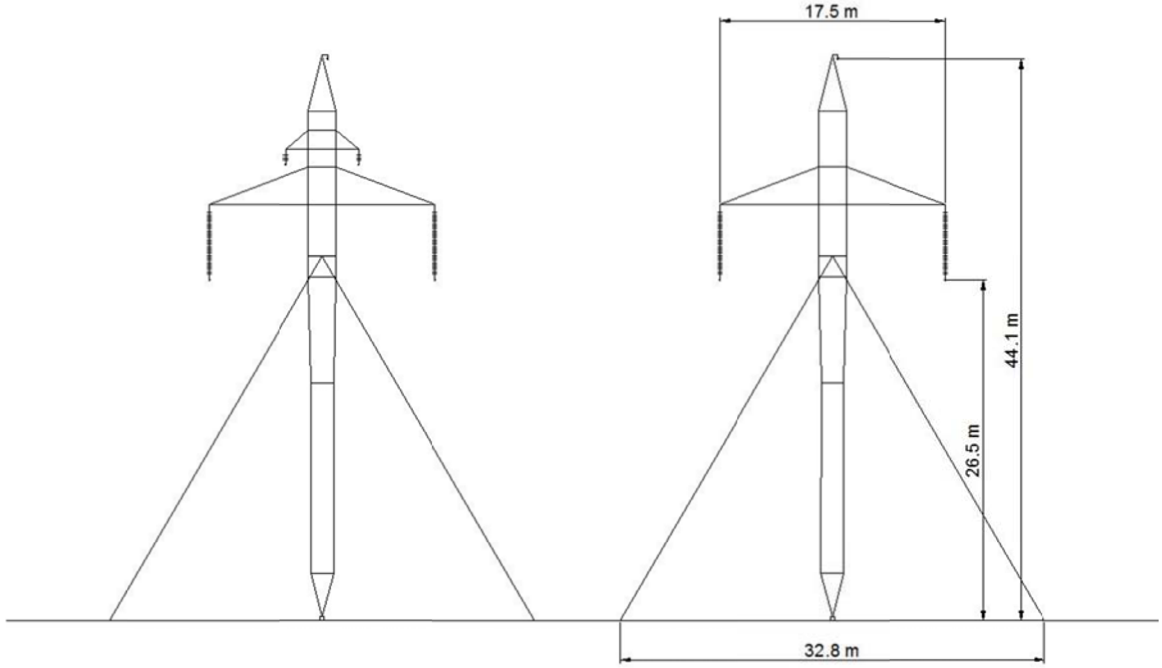
Other structures proposed are lattice steel self-supporting towers typically positioned at angle locations and other sections in the line for termination purposes or boundaries between weather-loading zones. Critical to the performance and maintenance of self-supporting structures are suitable foundations for the terrain type. Nalcor has identified these tower locations for detailed geotechnical exploration which is acceptable methodology for structures of these types. MHI concurs with the selection made on structure families and types for use in this project.

HVdc Transmission Line Structure Family

MHI reviewed Nalcor documents[41] "+/- 350 kV HVdc Tower Design Criteria A1 Dec 14, 2011" and "+/- 350 kV HVdc Transmission Line Design Criteria A1 Dec 2, 2011" which summarize Nalcor's design approach in determining the tower window geometry, span spacing, load capacity, and other detailed engineering criteria pertinent to the proposed HVdc transmission system. From extensive meteorological research, Nalcor determined that the transmission line would require 16 unique weather zones to adequately model the ice-and-wind loading on line structures.

Engineering work is in progress to complete the detailed design for the HVdc line. Nalcor has defined 12 structure families, with a total of 25 structure types[42], required to economically construct the line. Wherever possible, an effort was made to use common structures in the various loading zones in an effort to minimize the number of unique, custom structures which mitigates design and construction cost.

[41] Exhibit documents were presented at the meetings with Nalcor, but MHI was not allowed to retain copies.
[42] CE07, Nalcor, "350 kV HVdc Tower Types", June 12, 2012



HVdc Segment 1 (with electrode) HVdc Segment 2 (without electrode)

Figure 8: Typical HVdc Transmission Guyed Tangent Structures

Typical guyed tangent tower which comprise approximately 85% of the towers in the Labrador-Island HVdc transmission line.

Nalcor's design controlled the various combined ice-and-wind loading to the line structures by reducing or increasing the ruling span in the 16 weather-zone regions. Generally, as the ice-and-wind-combined loading increased, the design ruling span was reduced. This is an acceptable approach to controlling the structure size and weight, and ultimately construction and logistics costs.

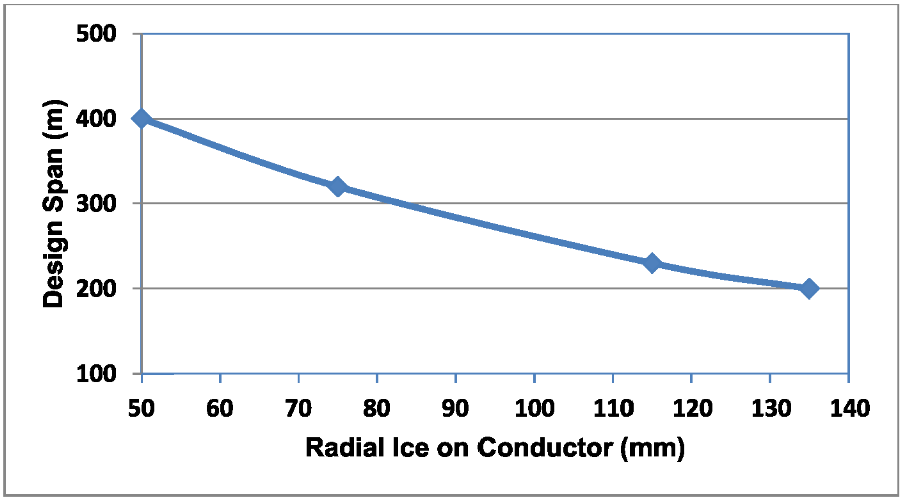


Figure 9: Design Spans for Ice Loading

MHI has reviewed the various ice-and-wind loading cases and required structure families and has determined 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.

AC Transmission Line Structure Family

MHI reviewed Nalcor documents[43] "+/- 315 kV HVac Tower Design Criteria B2 March 23, 2012" and "+/- 315 kV HVac Transmission Line Design Criteria B2 February 2, 2012" which summarized Nalcor's design approach in determining the tower window geometry, span spacing, load capacity, and other detailed engineering criteria pertinent to the proposed HVac transmission system running from the Churchill Falls Switching Station to the Muskrat Falls Switching Station.

Two 315 kVac lines are proposed, and Nalcor has advised that only one structure family with five different tower types is required for the route. The structure family is composed of guyed steel lattice structures with self-supporting angle and termination structures. As this line is predominantly in one weather-loading zone, MHI concurs with Nalcor's decision in selecting this structure family design.

Electrode Line

For reasons of life-cycle economics and reliability, the electrode line on the Labrador portion of the HVdc line was recently moved from individual wood pole structures located along the right-of-way edge to a position on the HVdc line structures from Muskrat Falls to

[43] Exhibit documents were presented at the meetings with Nalcor, but MHI was not allowed to retain copies.

Forteau point. MHI finds it is a prudent decision to consolidate the HVdc pole and electrode conductors onto one supporting structure in the Labrador transmission line section. There are considerable cost savings in construction effort, material, and the long-term maintenance required of wood pole structures.

From Forteau point to the Labrador Electrode site at L'Anse-au-Diable, and from the Soldiers Pond Converter Station to the Dowden Point electrode site, the electrode line is suspended on standard wood pole structures of similar size to a distribution pole system. MHI concurs with the design methodology that Nalcor selected for the electrode line system.

2.4.6 Assessment of Transmission Line Reliability

Nalcor made several prudent decisions regarding the detailed transmission line design to reduce the probability of an outage, and failure or progression of failures in line structures with the intent to increase the line's overall reliability. The following salient points highlight these decisions:

- The guyed structure configuration will naturally resist failure from cascading events and is more stable in the rugged terrain found along the route
- Provision of special anti-cascade towers every 10 to 20 structures to contain and isolate failures and prevent them from impacting large sections of line
- In sections of the transmission line with the most severe combined ice-and-wind loading, the spans have been shortened appropriately to reduce structure loading to manageable levels
- Selection of a single large conductor in place of a multi-bundled conductor arrangement[44]. This prevents ice accumulations bridging across sub-conductors to form large shapes which would transfer high wind loads to structures. Nalcor has selected a large 3 640 MCM 91-Strand all-aluminum conductor (AAC) family for the entire transmission line, and is currently investigating the use of high-strength aluminum alloy conductors of identical size for use in the extreme ice regions required to maintain reliability.
- Insulator purchase is limited only to vendors with international reputations for quality, operational reliability who have established distribution networks to comply with delivery schedules
- Due to the effect the rolling terrain has on tower locations and optimization, the average tower strength utilization on tangent towers will be somewhat less than the designed capacity, with utilization possibly averaging between 75% and 85% of the

[44] CE23, SNC Lavalin, "350 kV HVdc Conductor Optimization and Selection", Feb 7, 2012

ultimate strength. This has the effect of increasing tower resistance and stability during extreme weather events, thus increasing overall reliability.

- Selection of the final alignment within the route corridor attempted to minimize exposure to the extreme climatic-loading regions such as Long Range Mountain Ridge, and to avoid areas where the terrain acts to accelerate and funnel the wind
- Tower window dimensions and spans are designed to comply with the most up-to-date theory predicting conductor motion in extreme wind and ice events. This will reduce or eliminate outages during these events, increasing the overall transmission line reliability.
- Tower prototype testing on the most common line structures to affirm capacity and behavior under loading is scheduled for late 2012.

MHI finds Nalcor has completed a thorough assessment of the various climatic regions impacting the ±350 kV HVdc line from Muskrat Falls to the Soldiers Pond transmission line route and past meteorological research resulting with the line being apportioned into 11 sections, each with a unique zone-specific climatic loading[45].

The climatic loadings for each line section selected on a 1:50-year return period based on Nalcor's past research studies, as outlined in the document "Muskrat Falls Project –Exhibit 97, Appendix A Revision 1," are approximately equivalent to the climatic loading calculated assuming a Canadian Standards Association (CSA) 1:500-year return period.

There are additional recommendations in CAN/CSA C22.3 which recommend a greater reliability of design to 1:150-year or 1:500-year return periods for lines of voltages greater than 230 kV which are deemed of critical importance to the electrical system. The ±350 kVdc and 315 kVac lines proposed and configured for the Lower Churchill Project will, once operating, operate as a critical backbone for Newfoundland's electrical supply in the foreseeable future. These lines should, in MHI's opinion, be classified in the critical importance category due to their operating voltage and role in Nalcor's long term strategic plan for its transmission system.

Nalcor is aware of these additional reliability recommendations; however, through its own internal design policy, it has elected to not incorporate them in this project. With experience of Nalcor's existing transmission infrastructure, and after internal management review, Nalcor has adopted a 1:50-year climatic return which meets the minimum reliability requirements outlined in CAN/CSA C22.3 for high voltage transmission lines.

[45] CE22Exhibit 97, Appendix A Revision 1, Muskrat Falls Project

2.4.7 Emergency Response Plan

MHI is not aware of any formalized emergency response plan that Nalcor has made for an HVdc outage scenario. Informal discussions with key Nalcor staff were held on the topic to determine what, if any formalized emergency restoration is planned. Emergency response times to restore the line to normal operating conditions are very difficult to predict due to the remoteness of the transmission line and levels of failure possible. Outage periods up to one month or greater in remote line sections are possible.

The items addressed for possible follow-up in a restoration plan may include:

- Purchase and strategic storage of material caches. Material for caching may be purchased with the primary material orders to take advantage of bulk costing.
- Development of access and restoration trail-way system. This should be done during primary construction.
- Design of temporary emergency structures and anchoring devices which may be flown in to remote tower sites.

Since Nalcor has selected the minimum reliability period of 1:50 years as its design basis, ***MHI recommends Nalcor undertake a formal study to examine conceivable emergency response scenarios.***

2.4.8 Summary

The following is a summary of the key findings from the review of the information gathered and interviews held with the Nalcor project team.

The Nalcor project management team is utilizing an experienced consultancy firm to prepare the detailed design, material, and construction cost estimate taken forward to Decision Gate 3. Nalcor is utilizing highly professional staff with engineering and project management backgrounds to manage, track, and direct the consultant using accepted project management practices.

The transmission line structures and routes selected for all transmission facilities are cost-effective considering the terrain, route, and climatic loading expected. From the review of the written documentation provided, design methodology, and information recorded in the Nalcor staff interviews, MHI is satisfied the Decision Gate 3 estimate for all transmission facilities was prepared with high skill and diligence and is expected to be accurate to AACE International Class 3 level (+30% to -20%).

MHI recommends that Nalcor develop an emergency response restoration plan including access routes, material caches and equipment which can be mobilized quickly.

The design and construction schedule proposed by Nalcor is achievable provided there are no major changes to the project scope, unusual weather encountered during construction seasons, and adequate contractors retained with resources available.

The risk of cost escalation during the construction stage is high considering very competitive labour rates and compensation that will be required to attract qualified contractors and personnel. This escalation risk may not be fully accounted in the Decision Gate 3 estimate.

In its evaluation of the conductor optimization and selection report prepared by SNC Lavalin, MHI noted to Nalcor the report did not examine in sufficient detail the reliability issues of the recommended conductor operating in the severe icing regions along the Long Range Mountains. Nalcor has indicated a study of this technical issue is under way to examine the use of extra high-strength aluminum alloy conductors in these regions. The approximate 20% cost premium for these conductors is not included in the Decision Gate 3 estimate, but since the severe icing regions represent only 15% of the transmission line length, the impact to the total project budget if the alloy conductor is implemented is negligible.

In MHI's opinion, Nalcor undertook extensive due diligence in its design methodology designing the transmission line to withstand the many unique and severe climatic loading regions along its line length. However, by Nalcor assessing and selecting only a 1:50-year climatic return period, the HVdc line will only meet the minimum reliability requirements for the high voltage transmission line.

2.5 Strait of Belle Isle Marine Crossing

The configuration of the Strait of Belle Isle (SOBI) cable crossing has not changed significantly from Decision Gate 2.

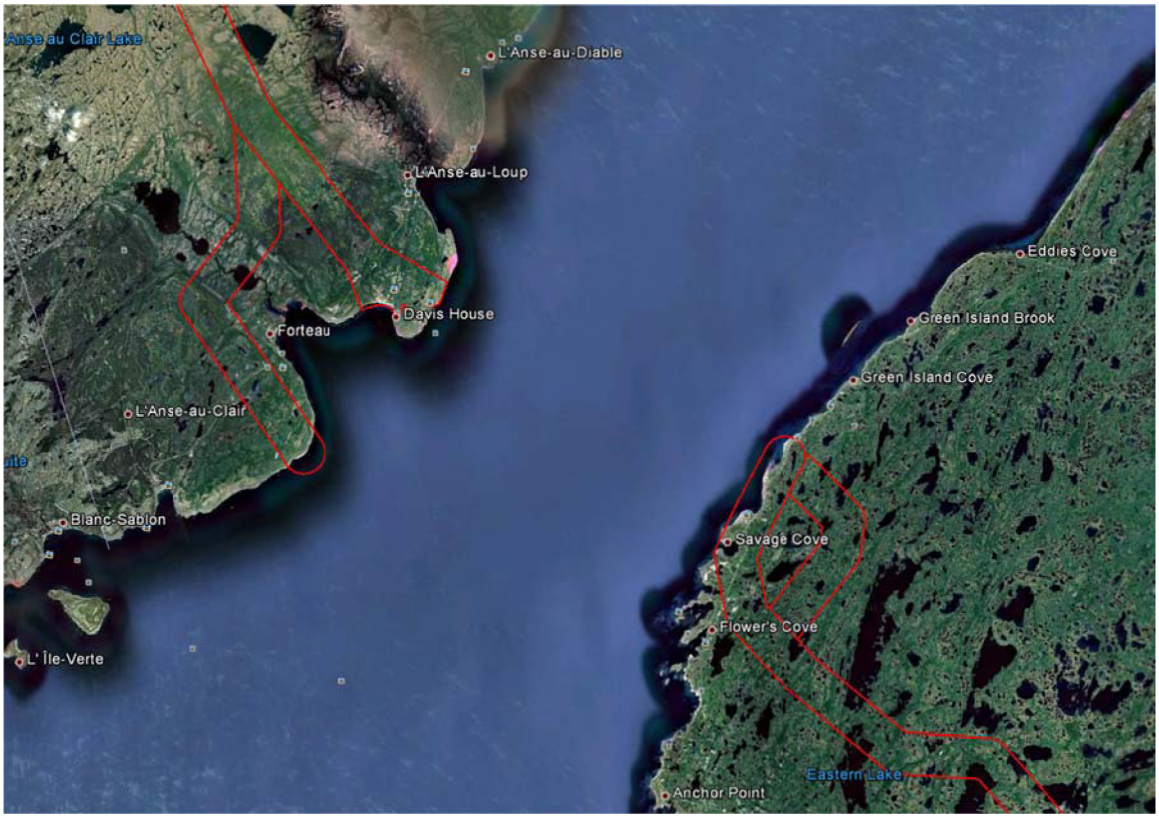


Figure 10: Strait of Belle Isle Marine Crossing Location

Further refinement of the route is being investigated to firm up the shore approaches, the horizontal directional drilling (HDD) techniques, the sea floor routing, the cable-laying technology, and the rock berm placement. There are ongoing studies of the currents and tides in the Strait, and continued surveillance of iceberg movements and roll rates in the vicinity. An observation tower has been erected to track movement of icebergs through the Strait and record actual roll rates. The status of these works was reviewed during meetings with Nalcor and the Engineer responsible for this segment of the project.

2.5.1 Comparison of Decision Gate 2 with Decision Gate 3 Findings

Significantly more knowledge has been gleaned in all aspects of the marine crossing project. There have been ongoing discussions with the potential cable suppliers, the cable has been tendered and an award is imminent. A decision has not been reached as to embedding a fibre-optic cable for communications, and while this would enhance reliability, it would also add to the cost but is not expected to materially impact the outcome of the CPW analysis.

Considerable work has also been done with cable-laying contractors, rock berm contractors and a test HDD bore hole was drilled from the Mistaken Cove Landing site on Newfoundland for a distance of approximately 1,500 m. Drill rates were assessed during this test and were slightly longer than previous Decision Gate 2 estimates. Some problems were encountered with fractured rock but grouting procedures proved workable. The bore hole was reamed out to 14 in. in some areas and 24 in. in others without any significant problems. These diameters are a specified requirement for the steel liner to be placed. It may be possible that the other two bore holes may be drilled at a lower depth to prevent the intersection of the fractured rock and subsequent requirement for grouting. Although the bore hole was not completed to the subsea floor, it is very likely that drilling re-entry will be done and the test hole used for one of the three cables.

From discussions with potential installers, it is expected that the laying of the cable on the sea bed can be completed in approximately 45 days. Iceberg flows typically prevent a startup of work in the Strait until at least June 1. The work season in the area usually extends to late October so there appears to be ample time to complete this work in one summer season, rather than the two-year program originally envisioned at Decision Gate 2.

The undersea cable market is extremely tight at present, and receiving an adequate supply of cable in 2015 is unlikely, thus this further reinforces the decision to defer to one construction season, in 2016. This of course increases the risk of completing the project as planned, but due to the delay of the in-service date for the first unit from Muskrat Falls until July, 2017, there would likely be time in the spring of 2017 to complete and commission the project.

On the positive side, if the project is completed and the HVdc lines and convertor stations are in service by the fall of 2016, it may be possible to transmit a portion of the recall power from Churchill Falls over the line with significant savings in fossil fuels at the Holyrood Generation Station.

It has been determined that all of the cables can be placed on the laying vessel, reducing the time required to reload during the installation exercise. It is expected that the cable can be floated at the Labrador side and a joint made on board the laying ship with the cable from the shore approach.

Discussions with rock berm suppliers may facilitate a reduction in the size of the berm required as a means of saving capital expenditures, although this decision has not been made at this point. Subsequent to Decision Gate 2, information has also been made available on a new technique for removing the rock berm should it be necessary to facilitate a repair to the cable. This new method would involve vacuuming the rock off the berm, which allows removal of rock up to 16 inches in diameter. Several qualified Canadian contractors have been trained in the use of this equipment.

2.5.2 Schedule and Estimates

The cable for the 32-km crossing has been tendered and three bids have been received. Suppliers have quoted firm prices in Canadian dollars for cable delivery in2015-2016. As noted earlier, a decision is pending on whether or not to embed fibre for communications. This inclusion would add to the cost but improve reliability rather than rely on line-of-site communication towers on either side of the Strait.

The conductor was originally specified at 320 kV and has subsequently been upgraded to 350 kV with a corresponding increase in price. However the increase in line-carrying capacity will result in minimizing line losses and improve the business case for the higher voltage cable. The larger conductor will also support an increased pulling capacity, better facilitating installation.

The Strait of Belle Isle cable crossing will likely create a 1-km to 1 ½-km drag-free no-fish zone. Scallop trawlers are the most likely vessels to create a problem with the cable. There are approximately 55 licences issued to fishers with equipment capable of fishing in the area but only 13 of the licensed are currently active. Discussions are ongoing with these fishers to educate them on the characteristics of the cable and rock berms.

The land-trenching costs are likely to be somewhat higher than DG2 based upon the observed rate of progress on the test bore hole and unit costs for construction.

There are also several opportunities to reduce costs from the Decision Gate 2 estimate. There may be potential to shorten the crossing distance from 32 km to 29 km after further investigation of the profile of the trench in which the cable will lay. There is also potential to optimize the amount of rock used on the berm. Approximately 900,000 cubic metres has been estimated at Decision Gate 2. Rock placement has been estimated to cost $75/ton placed. A request for proposal is scheduled to be issued at the end of summer 2012 which will firm up both the quantity and cost of rock to be placed.

It may also be possible to reduce the planned size of the HDD bore hole. Any reduction in size will increase drill rates, shrink the size of the steel liner and therefore lower the overall cost of the SOBI crossing. The SOBI cable crossing has been adequately redefined from Decision Gate 2 to Decision Gate 3 and the planned approach to the project optimized. While there has been an increase in overall costs, there have also been several opportunities noted for possible reduction in costs.

MHI considers the project construction schedule to be reasonable but all onshore and HDD should be completed in advance of receipt of the cable. Completing the subsea portion of the project in one construction season adds additional risk to the planned project.

2.5.3 Summary

The costs have increased from Decision Gate 2 to Decision Gate 3 but are considered to be reasonable and within the AACE Class 3 estimate range. MHI is of the opinion that there is an equal likelihood that the costs will decrease, as a result of changes in route selection, size of bore holes used, and reduction in size of the rock berms, as there is of costs increasing.

2.6 Muskrat Falls Generating Station Development

In January, 2012, Manitoba Hydro International submitted the "Report on Two Generation Expansion Alternatives for the Island Interconnected Electrical System"[46], which included a review of Nalcor's Muskrat Falls Generating Station plans from the perspective of technical and construction feasibility and cost estimate. Nalcor's work was assessed as to its suitability for Decision Gate 2 purposes and input to a cumulative present worth (CPW) analysis. The new review covers Nalcor's work since Decision Gate 2 in preparation for Decision Gate 3 and is based on information provided by Nalcor in June, 2012.

This section of the report describes the schedule and cost implications of the Muskrat Falls Generating Station including ac Switchyard Upgrades and Transmission Lines to Churchill Falls.

2.6.1 Scope of Work

A high-level review of the Muskrat Falls Generating Station post-Decision Gate 2 design changes, associated switchyards, and 315 kV transmission lines to Churchill Falls was completed. Cost estimates and construction schedules completed by Nalcor in preparation for Decision Gate 3 were examined and an assessment was made of their reasonableness as inputs to a CPW analysis.

The following meetings and reviewed information were used to prepare this study:

- A briefing by Nalcor's Project Director, Deputy Project Director, and Engineering Manager on post-Decision Gate 2 design, schedule, and budget changes. Review of

[46] Weblink, http://www.pub.nf.ca/applications/MuskratFalls2011/MHIreport.htm

the change management process used to manage these changes. This briefing transpired on June 18, 2012.

- CE25, Nalcor, "Muskrat Falls and LIL Basis of Design", not dated.
- Overarching Contracting Strategy (LCP – PT-MD-0000-PM-ST-0002-01)
- Lower Churchill Project (LCP) – Phase 1 Master Package Dictionary
- CE27 Rev. 02, Nalcor, "LCP Phase 1 DG3 Estimate; Excludes Maritime Link Project"
- CE32, Nalcor, "High-level Muskrat Falls milestone construction schedule DG2 (LCP MF & IL MS Project JHE 2010-07 05.mpp)", June 19, 2012.
- CE28, Nalcor, "High-level Muskrat Falls milestone construction schedule DG3", June 6, 2012.
- CE29, SNC Lavalin, "Project Schedule – Overview of the Project Schedule covering the area powerhouse", April 8, 2012.

2.6.2 Muskrat Falls Generating Station

Design and Engineering

The major changes in project scope since Decision Gate 2 are as follows:

- Reorientation of the powerhouse in the river by approximately 30^0
- The spillway configuration change from a four-radial gate to a five-vertical gate arrangement
- A significantly more massive powerhouse intake structure
- The south dam changed from a roller-compacted concrete (RCC) structure to a rock fill dam
- The addition of a second service bay at the north end of the powerhouse
- The addition of an RCC cofferdam to the bulk excavation work contract.

From discussions with the Lower Churchill Project (LCP) team and a review of sample change management documents, the changes in project scope appear to be based on sound engineering principles and have been effectively incorporated into the current project schedule and budget.

The Lower Churchill Project team believes that the overall design and engineering are currently approximately 40% complete. Although a comprehensive review of the design was not within the scope of this review, the level of detail provided and evidence in the selected samples of the schedule and budget information supports this degree of completion.

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

2.6.3 Schedule

The major schedule changes post-Decision Gate 2 are as follows:

- Delay of the project start by 11.5 months to September 21, 2012, primarily as a result of delays in the Environmental Assessment and licensing process
- Revisions to work package timing and durations as a result of post-Decision Gate 2 design and engineering changes and refinements
- First power date delayed by approximately 10 months to July 15, 2017.

The high-level schedule that was reviewed reflected the project contracting strategy and depicted the key project activities that impact the project schedule. The schedule is consistent with the current contract packaging strategy and has considered labour workforce levelling. Based on a sample review, the schedule is sufficiently supported by a very detailed work breakdown structure that should address project and construction management, and cost control during project execution.

There are a few areas in the schedule that will be challenging, for example, early installation of the project infrastructure, RCC cofferdam construction, and the main structures concrete. In discussion with the project team, however, it is apparent that they are well aware of these issues and are taking measures to manage the risks associated with the components of the schedule.

From an overview perspective, the project scheduling is comprehensive, detailed, and consistent with best industry practice for similar projects. The current project schedule is appropriate and reasonable to meet the requirements of Decision Gate 3.

2.6.4 Cost Estimates

From Decision Gate 2 to Decision Gate 3, the Muskrat Falls Generating Station project cost estimate increased by 21% after allowing for a decrease of escalation and contingency funds in 2012 relative to 2010.

The Decision Gate 3 estimate incorporates the design changes subsequent to Decision Gate 2 and is based on upgraded quantities derived from design development, recent pricing and quoting from suppliers, and updated labour pricing.

Nalcor considers the Decision Gate 3 cost estimate to be better than a Class 3 estimate through the Association for the Advancement of Cost Engineering International (AACE), which has an accuracy of +30% and -20%, and thus would be considered reasonable for the Decision Gate 3 project sanction stage.

It is noted that the overall Muskrat Falls project contingency in the Decision Gate 3 estimate is 6.7%, which in MHI's experience, is low for this level of estimate. This has been discussed with the Nalcor project team, and the Nalcor project team believes that the current Decision Gate 3 estimates input detail and conservative assumptions justify the chosen contingency amount.

From an overview of the methodology and detail of the current project estimate, the Muskrat Falls project contingency has been reduced substantially from Decision Gate 2 and may be somewhat low.

2.6.5 Labrador Transmission Assets

The Labrador Transmission Assets (LTA) include the 315-kV transmission lines from Muskrat Falls to Churchill Falls, and the switchyards at both Muskrat Falls and Churchill Falls.

The major design engineering changes post-Decision Gate 2 are as follows:

- The inclusion of the 735-kV equipment into the Churchill Falls Switchyard, which had previously been attributed to the Gull Island Generating Station project
- The power lines from the powerhouse unit transformers to the switchyard were changed from underground cables to overhead lines. This change was due to the reorientation of the powerhouse by approximately 30° with the river bed. This allows for a more conventional overhead line arrangement and which would be advantageous from both cost and schedule perspectives.

The current LTA schedule reflects the 11.5-month delay in project startup from Decision Gate 2, and has a projected service date of May 12, 2016.

The schedule, which is 33 months long and includes three winter construction periods, accounts for the clearing and construction of the 245-km-long 315-kV transmission line. This is a prudent and reasonable schedule given the length of line, the location, and the potential for unusual weather conditions. The schedule durations for HVdc switchyard design and construction, and procurement of the required transformers and switchgear appear reasonable.

The LTA estimate increased significantly from Decision Gate 2 to Decision Gate 3 as a result of including the 735-kV equipment at the Churchill Falls Switchyard, utilizing current international instead of local construction costs, and increased indirect costs such as construction camps. In consideration of the anticipated significantly increased transmission line construction activity across Canada over the planned period, the increased estimates for construction costs and construction camps are considered appropriate. The LTA has been redefined from Decision Gate 2 to Decision Gate 3 and has increased in costs significantly but now represents a reasonable estimate consistent with best industry practice.

2.6.6 Summary

The Lower Churchill Project team developed a comprehensive work breakdown structure for the Muskrat Falls Project that is consistent with the proposed contracting strategy. It is detailed enough to support a Decision Gate 3 level review of the scope, schedule, and budget, and to provide a framework for managing the project going forward.

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 approximately the 40% level, provides a significant increase in confidence in the Decision Gate 3 schedule and cost estimate over Decision Gate 2.

From a review of the information provided, Nalcor has performed the post-Decision Gate 2 design, scheduling and cost-estimating work for the Muskrat Falls Generating Station and the Labrador Transmission Assets with the degree of skill and diligence required by customarily accepted professional practices and procedures utilized in the performance of similar work. The current Lower Churchill Project design schedules and cost estimates are considered consistent with good utility practice. However, consideration should be given to the relatively low contingency remaining in the estimate. Other than the contingency factor, cost and schedule are sufficiently detailed and comprehensive to support a Decision Gate 3 and are appropriate for input into a cumulative present worth analysis with other options.

3 Isolated Island Option

3.1 Load Forecast

The purpose of this section is to compare the forecasts prepared for the 2012 Isolated Island option and the 2012 Interconnected Island option. The Isolated Island option is based on a higher marginal electricity price because the cost of future generation is more expensive. The higher marginal electricity price is expected to reduce future electricity consumption by encouraging conservation and discouraging electric space-heating installations, which will reduce or delay the need for future generation additions.

3.1.1 Comparison of the 2012 Isolated Island option and 2012 Interconnected Island option

The energy and peak forecasts for the Isolated Island option are lower than the respective forecasts for the Interconnected Island option (see Figure 11 and Figure 12). These differences are maximized by 2045, when the Isolated Island option energy forecast and peak forecast are lower by 487 GWh and 86 MW, respectively. After 2045, the gap narrows so that by 2067, the Isolated Island option energy forecast and peak forecast are lower by 276 GWh and 44 MW, respectively.

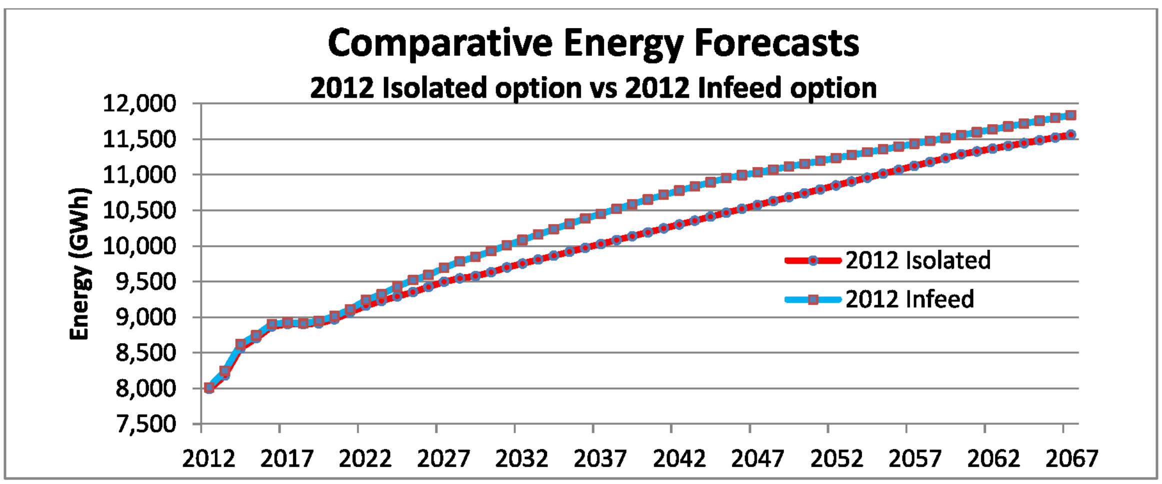


Figure 11: Comparative Energy Forecasts – The 2012 Isolated option versus 2012 Interconnected Island option

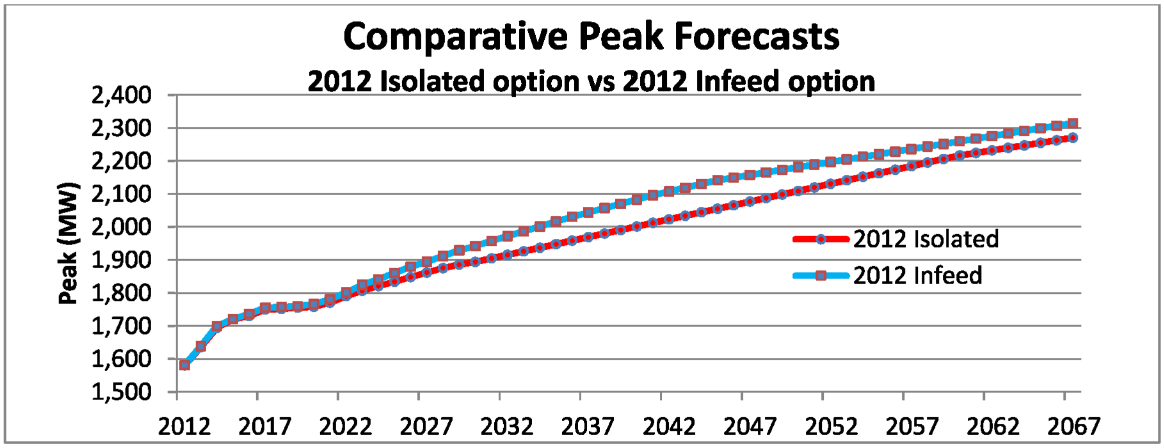


Figure 12: Comparative Peak Forecasts – The 2012 Isolated option versus 2012 Interconnected Island option

Table 8 demonstrates that the energy and peak differences between the two options are minimal in 2012. The main cause for the difference in energy consumption is energy reductions in the domestic sector. The general service and other load reductions are minimal throughout the forecast. There is no difference in the industrial load because both options use the same forecast.

Table 8: Comparison of the 2012 Isolated Island option and the 2012 Interconnected Island option – Net Differences

	Energy (GWh)					Peak (MW)
Year	Domestic	General Service	Industrial	Other	Energy	Peak
2012	-13	-6	0	-2	-21	0
2020	-48	-1	0	3	-46	-8
2029	-257	-4	0	-7	-269	-43
2045	NA	NA	NA	NA	-487	-86
2067	NA	NA	NA	NA	-276	-44

The reduction in the domestic forecast occurs because the Isolated Island option is based on a higher marginal electricity price. The higher marginal electricity price is due to the future generation for the Isolated Island option being more expensive than the Interconnected Island option. The higher marginal electricity price reduces the usage of electricity by encouraging conservation and by discouraging the installation of electric space-heating systems. By 2029, the difference in marginal electricity price is 1.13 cents, creating a 928 kWh reduction in domestic average use and a 257 GWh reduction in domestic load.

For both options, the extrapolated forecast assumes that the rate of new electric space-heating loads will be reduced after the 20-year forecast period. Since there is less electric space-heating load in the Isolated Island option, less energy is allocated each year, which widens the energy gap until 2045. By 2045, the Interconnected Island option reaches the maximum constraint for saturation of electric space-heating. The Isolated Island option does not reach the maximum constraint and continues to capture new electric space-heating load beyond 2045, which causes the energy gap to diminish over the later years of the extrapolated forecast period.

3.1.2 Comparison of 2012 Isolated Island Option to Historical Growth

Table 9 compares the 2012 Isolated Island option to historical growth. Total Island energy and peak requirements are expected to grow at a steady rate over the next 20 years. The 20-year Island energy forecast growth rate is 100 GWh and the 20-year Island peak forecast growth rate is 18 MW. These forecasts assume no industrial closures, but the forecast growth rates are still lower than the growth experienced over the last 40 years, which has been adversely affected by pulp and paper mill closures.

Table 9: Annual Growth per Year – Historical Growth and the 2012 Isolated Island option

Sector	Historical Growth Rate			Isolated Island option	
				Forecast Growth Rate	Extrapolated Growth Rate
	1971-2011 (40-Year)	1991-2011 (20-Year)	2001-2011 (10-Year)	2011-2031 (20-Year)	2031-2067 (36-Year)
Domestic (GWh)	77	42	65	42	NA
General Service (GWh)	44	24	32	21	NA
Industrial (GWh)	-13	-58	-132	31	NA
Other (GWh)	8	3	13	6	NA
Island Energy (GWh)	117	12	-23	100	52
Island Peak (MW)	25	3	11	18	10

The 20-year forecast growth rate for the domestic sector (42 GWh) is expected to be the same as the 20-year historical growth rate, which included the economic downturn of the 1990s, and 45% lower than the 40-year historical growth rate (77 GWh). MHI considers the domestic forecast for the Isolated Island option to be overly conservative. The general service, industrial, and other sector forecasts are similar to the 2012 Interconnected Island option, which is discussed earlier in this report, Section 2.1.

3.1.3 Summary

Similar to the findings in the 2012 Interconnected Island option (Section 2.1.4), the primary concern with the 2012 Isolated Island option is that the total Island energy and peak forecasts over the extrapolation period are too low. The extrapolated energy forecast is only 52% of the load expected over the next 20 years. The extrapolated peak forecast is only 56% of the load expected over the next 20 years. These reductions in future growth are significant and may be overly conservative. The extrapolated growth rates are significantly lower due to lower domestic average use, lower electric space-heating saturation, and the assumption of no new industrial loads locating on the Island over the extrapolation period.

3.2 Holyrood Thermal Generating Station

There are a number of alternates for Holyrood Thermal Generating Station, some of which only apply for the Interconnected option, some for the Isolated Island option, and some for both options. All options for Holyrood Thermal Generating Station are collected and discussed here. As most of the plans have been fully documented in the Decision Gate 2 review report, only the changes in scope or costs are noted as part of this report.

3.2.1 Holyrood Pollution Control Upgrade

As part of the Isolated Island base case in both Decision Gate 2 and Decision Gate 3, sulphur dioxide scrubbers (flue gas desulphurization) and particulate collection devices (electrostatic precipitators) were considered to be installed by 2018 and maintained for the economic life of the plant until 2035. Stantec Consulting Ltd. (Stantec) provided an update to the costs outlined in the previous study conducted in 2008[47].

Changes in Decision Gate 2 Findings for Decision Gate 3

Stantec performed a thorough review of the probable cost of the project to the current economic conditions in Newfoundland and Labrador. Stantec also reviewed any changes to environmental regulations that may have occurred that would impact the findings in the original report. Stantec used information from Statistics Canada, Consumer Price Indices for Newfoundland and Labrador, economic indicators, and Engineering News Records to establish an estimated revised cost.

The productivity factor for labour used in the 2008 Report was still considered appropriate for this study. However, Newfoundland and Labrador are currently experiencing a shortfall of skilled labour due to the increase in construction activity in the region. This is putting pressure on labour rates which were called up to more adequately represent the trend in the construction timeframe. Material prices are somewhat higher in 2012 versus 2008, and despite steel prices being lower overall there was a slight increase in the price allowed for materials.

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[47] CE03, Stantec, "Updated Precipitator and Scrubber Installation Study (2012) Holyrood Thermal Generating Station", May 7, 2012

The review of major equipment and subcontracts concluded that equipment has increased in price equivalent to inflation while the subcontract price of labour and installation has increased significantly.

Summary

The Stantec study concluded that the overall cost to add the scrubbers and precipitators to the Holyrood Generating Station has increased but is generally in line with inflation. The costs outlined in the new report are appropriate for use in the Decision Gate 3 CPW analysis for the Isolated Island Option.

3.2.2 Holyrood Life Extension

The Holyrood Life Extension was re-evaluated by AMEC in the spring of 2012 to update the work done for Decision Gate 2. The assumption of retaining the thermal generation plant at a capacity factor of 75% is similar to what was envisioned in Decision Gate 2. Holyrood was the only station evaluated and the study did not examine any additional thermal plants.

Changes in Decision Gate 2 Findings for Decision Gate 3

Both Decision Gate 2 and Decision Gate 3 considered Holyrood operating in the Isolated Island Option until 2035. The reliable operation of all three units was assumed. Plant staffing and contract maintenance was assumed to be equivalent to current levels. In both cases, sulphur dioxide scrubbers (flue gas desulfurization – FGD) and particular collections devices (electrostatic precipitators – ESPs) were considered to be installed by 2018, and maintained for the economic life of the plant. There were no synchronous condenser conversions of Units 2 and 3, and Unit 1 has already been done. High operating reliability and availability will be required in both cases.

A typical near end-of-life refurbishment would be in the range of $400/kW or $200 million for Holyrood, excluding the costs for the FGD and ESPs. The FGD would likely need to be refurbished in the 2023 to 2027 time range and is estimated to cost approximately $80/kW or $40 million.

Some additional FGD start-up costs and annual capital expenditures of $2 million/year were also likely. A modest refurbishment would occur in the 2025 time frame. The timing of the Holyrood refurbishment would likely be staged from 2013 to 2017. This would allow the plant to continue to provide reliable service and capacity. A second minor refurbishment would also be staged in the 2024 to 2026 time period.

Summary

The AMEC study essentially updated the Holyrood Thermal Generating Station life extension by bringing forward the estimates from Decision Gate 2.

3.2.3 Holyrood Thermal Generating Station Replacement

(to be drafted, no changes from DG2)

3.2.4 Holyrood Thermal Generating Station Synchronous Condenser Conversion

(to be drafted, no changes from DG2)

3.2.5 Holyrood Thermal Generating Station Decommissioning

(to be drafted, no changes from DG2)

3.3 Wind farms

The wind farms proposed in Decision Gate 2 were updated for inflation to reflect current costs. The Isolated Island option comprises one new 25 MW wind farm in 2014, and replacement of wind farms after 20 years of operation. Existing 54 MW of wind farms at Fermeuse and St. Lawrence will be replaced in 2028.

Changes in Decision Gate 2 Findings for Decision Gate 3

There were no new studies conducted as part of this process and costs were nominally increased to reflect escalating costs of wind turbines.

Summary

The two wind farms proposed have been updated as base cost estimates in the Isolated Island option.

4 Simple and Combined-Cycle Combustion Turbines

The thermal generation facilities considered for both the Isolated Island and Interconnection Island options did not change in capacity between Decision Gate 2 and Decision Gate 3. The Acres International studies of 1997 and November, 2001 had been used to develop a scheme of simple-cycle combustion turbines (CTs) and combined-cycle combustion turbines (CCCTs) for the Island, and were also used to provide updated costs for the 170 MW combined-cycle plants and 50 MW simple-cycle units. These studies were updated in April, 2012 by Hatch to reflect the current cost and operating environments.

Changes in Decision Gate 2 Findings for Decision Gate 3

In 1977, Acres International and Stone & Webster conducted a feasibility study to install combustion turbines at the Holyrood Generating Station. This original study considered various combined-cycle plants between 150 and 200 MW. The study concluded that natural gas would be unavailable and heavy fuel was eliminated due to excessive maintenance requirements and engine performance derating. Thus the early decision was to fuel the plant using diesel. A two pressure nonreheat cycle was selected and a single turbine configuration was chosen.

In 2001, the study was updated for combined-cycle plants in two capacity ranges, 125 MW and 175 MW. The update included data on plant performance, project capital costs, project schedules, operating and maintenance cost updates and environmental impacts. These costs were then escalated using appropriate indices for use in Decision Gate 2 estimates.

As noted earlier in April, 2012 the estimates were updated using the 1997 and 2001 reports as the basis steam conditions and climate conditions were assumed to be consistent with the two previous studies. However in this case, budget prices were solicited from vendors for major equipment including a delivery schedule. In some instances values were updated based on factoring from previous projects.

Summary

While the actual April, 2012 Hatch study was not reviewed, the methodology used to develop a revised estimate was reasonable and reflects state of the art industry practices for a project at the Decision Gate 3 level.

5 Small Hydroelectric Plants

5.1 Island Pond and Portland Creek Generating Station Development

The configuration of the Island Pond Generating Station and the Portland Creek Generating Station developments remained unchanged in their configuration between Decision Gate 2 and Decision Gate 3. SNC Lavalin had conducted a detailed project design and engineering analysis in 2006[48]. This study was updated in April, 2012 to reflect the current cost and operating environments.

Changes in Decision Gate 2 Findings for Decision Gate 3

As the design and engineering from Decision Gate 2 to Decision Gate 3 did not change, a group of relevant escalation indices were tabulated, and a composite index was prepared for the years 2006 and 2012. The resulting escalation index, representing the general cost increase from 2006 to 2012, was applied to all of the unit prices and a revised lump-sum price was established.

Schedule and Cost Estimate for Decision Gate 3

The escalated unit and lump-sum pricing was compared to equivalent pricing from other similar projects. When it was found that the comparative pricing differed significantly with the escalated project pricing, an adjustment was made to the escalation index for that price in the updated project cost estimates. Where practical, such as gate and hoist equipment, an evaluation was made of estimated weights for equipment and applicable unit prices to determine a rational price.

No consideration was given to a premium which could reflect the current state of construction labour in Newfoundland and Labrador.

Unit prices for both Portland Creek and Island Pond hydroelectric projects are in many cases the same for equivalent work items, the exceptions being where there are different conditions from one project to the other.

Summary

[48] Exhibit 5b, SNC Lavalin, "Studies for Island Pond Hydroelectric Project", December 2006

The approach chosen to update the estimates on both the Island Pond Generating Station and Portland Creek Generating Station projects is reasonable given the static nature of the design and engineering. The revised costs are suitable for a representation of the Decision Gate 2 estimates.

5.2 Round Pond Generating Station

The Round Pond Generating Station development was initially investigated by Acres International in 1985, and the concept was updated in a feasibility study conducted by Shawinigan/Fenco in 1982/1988. Newfoundland and Labrador Hydro undertook companion studies of transmission, telecontrol, and environmental issues, and issued a Summary Report in February, 1989 incorporating the findings from the Shawinigan/Fenco investigations. This study was used for Decision Gate 2.

Hatch Consultants updated costs in April, 2012 to reflect current cost and operating environments. This study will be used for Decision Gate 3.

Comparison of Decision Gate 2 Findings with Decision Gate 3

Hatch updated the initial cost estimates by applying its own proprietary estimating package to unit prices for all civil works. Hatch applied labour rates based on current labour agreements applicable to the 2012 market environment in Newfoundland and Labrador. The equipment rates were based on leasing of equipment by contractors, with consideration for the present heavy schedule of projects in the province. This approach was considered to be reasonable, although different than the approach used for both the Island Pond Generating Station and Portland Creek Generating Station developments.

Schedule and Cost Estimates for Decision Gate 3

Electrical and mechanical direct costs include the purchase and installation of turbine and generator equipment, and all mechanical and electrical equipment including gates, guides, and hoists. Estimates for mechanical equipment are based on Hatch's database of applicable contract and tender pricing combined with appropriate escalation and rating adjustments to match the Round Pond Generating Station technical parameters and estimate date. Indirect costs were also sufficiently covered.

Summary

The approach selected by Hatch Consultants to update the original studies is reasonable given the static nature of the design and engineering. The revised costs represent a reasonable representation of a Decision Gate 2 estimate used for a Decision Gate 3 base case comparison.

6 Financial Analysis of Options

By Mack Kast, subsequent to the CPW visit.

6.1 Introduction

Capital cost sensitivities

Fuel Price sensitivities

Load forecast sensitivities

6.2 Isolated Island CPW Analysis

6.3 Interconnected Island CPW Analysis

6.4 Comparative Analysis and Sensitivities

7 Conclusions and Recommendations

(to be completed last)

Appendix A: Bibliography of Documents

Exhibit	Title / Description	Prepared by	Date
CE01	Long Term Planning Load Forecast 2012 PLF Presentation (Initial)	Nalcor Energy	2012
CE02	Isolated Island Base Cost Estimates and Escalation Factors	Nalcor Energy	2012
CE03	Updated Precipitator and Scrubber Installation Study Executive Summary	Stantec Consulting Ltd.	2012
CE04	Nalcor Comparative Study & Cost Growth Since DG2	Nalcor Energy	2012
CE05	LCP HVDC Project Control Schedule	Nalcor Energy	2012
CE06	Questions from Al Snyder - Isolated Island CE02	Paul Wilson	2012
CE07	350 kV HVdc Tower Types	Nalcor	June 12, 2012
CE08	350kV HVdc Conductor Sags - 400 m Ruling Span	SNC-Lavalin Inc.	2011
CE09	HVdc transmission corridor (Google earth file)	Nalcor Energy	2012
CE10	Transmission Deviation Alerts and Change Notices	Nalcor Energy	2012
CE11	3640 ASC HVdc Conductor Properties - Canadian Sizes	Nalcor Energy	2012
CE12	Transmission Line Project Schedule	Nalcor Energy	2012
CE13	Reliability and Availability Assessment of the HVdc Island Link	SNC Lavalin Inc.	2012
	This report presents the results of the reliability and availability analysis carried out to determine the expected performance of the ±350 kV, 900 MW HVdc interconnection between Muskrat Falls and Soldiers Pond (Island Link). The Maritime Link between Bottom Brook and the Nova Scotia power system was not considered in this study. The results consider the performance of each element of the Island Link as well as the composite reliability of the complete link from Muskrat Falls to Soldiers Pond.		
CE14	Construction Power System Study	SNC-Lavalin Inc.	April 2, 2012
	The construction power study examined options to supply a maximum of 12 MW of load in 2015 at the Muskrat Falls construction site on Labrador.		
CE15	Harmonic Impedance Studies	SNC-Lavalin Inc.	March 6, 2012
	This report presents the results of the harmonic impedance studies carried out to determine the range of harmonic impedances presented by the ac systems at the terminals of the HVdc interconnection between Muskrat Falls and Soldiers Pond (Island Link).		
CE16	HVdc System Modes of Operation and Control Strategies Study	SNC-Lavalin Inc.	April 17, 2012

	This report presents a description of HVdc configurations, HVdc control hierarchy, control locations, modes of operation, and operating and control strategies of the scheme, as applicable to the Island Link.		
CE17	Load Flow and Short Circuit Studies	SNC-Lavalin Inc.	April 5, 2012
	The Load Flow and Short Circuit studies examine the impacted power system for equipment ratings violations and voltages.		
CE18	Reactive Power Studies	SNC-Lavalin Inc.	Dec 7, 2011
	This report presents the results of the reactive power studies carried out to examine the steady-state reactive power capabilities of the ac systems at the converter ac buses with the HVdc interconnections between Muskrat Falls and Soldiers Pond (Labrador Island Link) and between Bottom Brook and the Nova Scotia power system (Maritime Link). Starting from the base case scenarios provided by Nalcor, the present studies are designed to determine the maximum and minimum levels of reactive power that can be provided/absorbed by the ac systems in both normal and single contingency outage conditions. These limits will be used by the converter manufacturer in the design of both the converters themselves and the associated harmonic filter banks, if these are required.		
CE19	Stability Studies	SNC-Lavalin Inc.	March 6, 2012
	The stability studies in this report examined the impact of the 900 MW Island Link and the 500 MW Maritime Link on the Island of Newfoundland as well as the ac network between Churchill Falls and Muskrat Falls in Labrador.		
CE20	HVDC tower outline	Nalcor Energy	2012
CE21	Nalcor Emera Term Sheet (signed)	Nalcor Energy	2010
CE22	Ice Loading Region Maps (DG2: Exhibit 97 rev 1)	Cox & Palmer	2012
CE23	350kV HVdc Conductor Selection, SNC Lavalin Report	SNC Lavalin Inc.	Feb 7, 2012
CE24	LCP Asset Schematic by Project (ex ML)	Nalcor Energy	2012
CE25	7.2 Muskrat Falls Generation Basis of Design Document	Nalcor Energy	2012
CE26	LCP Phase 1 DG3 Final Estimate Excl Maritime Link Project	Nalcor Energy	2012
CE27	LCP Phase 1 DG3 Estimate Rev 02 w DG3-DG2	Nalcor Energy	2012
CE28	Time Risk Model May 2012	Nalcor Energy	2012
CE29	SNC Project Schedule DG3 Planning Basis	SNC-Lavalin Inc.	2012
CE30	Project Control Schedule Doc Sec 7.4, 7.5	Nalcor Energy	2012
CE31	Duplicate (See CE04)	Nalcor Energy	2012
CE32	Nalcor Energy - LCP 001 JUNE	Nalcor Energy	2012

CE33	Costs: Intake & Powerhouse, Spillway Structure Direct Costs	Nalcor Energy	2010
CE34	Guideline for Unit Maximum Loading	NLHydro	2011
CE35	Capacitor and Reactor Locations	Nalcor Energy	2012
CE36	Generator Under Frequency Protection Settings	Nalcor Energy	2012
CE37	Current LCP-PCS Project Control Schedule 4.11.2012	Nalcor Energy	2012
CE38	Churchill Falls Location Drawing Extension of 735 kV New 315 kV Substation	SNC-Lavalin Inc.	2012
CE39	Soldiers Pond Station Location Plan 230 kV Switchyard and Converter Substation	SNC-Lavalin Inc.	2011
CE40	Muskrat Falls Station Location Plan 315-138kV Switchyard and Converter Station	SNC-Lavalin Inc.	2011
CE41	230kV Soldiers Pond Switchyard Single Line Diagram	SNC-Lavalin Inc.	2011
CE42	735-315kV Churchill Falls Switchyard Extension Single Line Diagram	SNC-Lavalin Inc.	2011
CE43	Muskrat Falls HVdc Trans System Overall Single	SNC-Lavalin Inc.	2011
	The system single line diagram (SLD) reviewed consists of the HVdc converter stations (dc yard) at both terminals with electrode sites, a new 315 kV ac switching station at Muskrat Falls, ac system extension at Churchill Fall 735 kV / 315 kV switching station, and a new 230 kV ac station at Soldiers Pond.		
CE44	315-138 kV Muskrat Falls Switchyard Single Line Diagram	SNC-Lavalin Inc.	2011
CE45	LCP Short Form Technical Specification Converter Stations	SNC Lavalin Inc.	Oct 12, 2011
	A Short Form Technical Specification is draft for the converter station to obtain budgetary pricing and additional information for the LCC converter stations at Muskrat Falls and Soldiers Pond Converter Stations in a 900 MW, +/- 350 kV for the Lower Churchill bipole HVdc project.		