Manitoba HYDRO INTERNATIONAL

Report on Two Generation Expansion Alternatives for the Island Interconnected Electrical System

Volume 2: Studies

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Permit to Practice

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

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Abbreviations

Abbreviation	Definition
A, kA	Amperes, kilo Amperes
ac	Alternating current
AACE	Association for the Advancement of Cost Engineering
ABB	Alstom (formerly ABB)
AEB	Atmospheric Environment Branch
AES	Atmospheric Environment Services
AFUDC	Allowance For Funds Used During Construction
AMP	Asbestos Management Plan
ARSP	Acres Reservoir Simulation Package
B&W	Babcock and Wilcox
BOOT	Build-own-operate-transfer
CAN/CSA	Canadian Standards Association
CCC	Capacitor Commutated Converter
CCCT	Combined Cycle Combustion Turbine
CCGT	Combined Cycle Gas Turbines
CDA	Canadian Dam Association
CDF	Construction Design Flood
CDM	Conservation and Demand Management
CE	Confidential Exhibit
CEA	Canadian Electrical Association
CEI/IEC	International Electrotechnical Commission
CF	Churchill Falls
CF(L)Co	Churchill Falls (Labrador) Corporation
Cigré	International Council on Large Electrical Systems
CO2	Carbon Dioxide
COS	Cost of Service
CPI	Consumer Price Index
CPW	Cumulative Present Worth
CS	Converter Station
CT	Combustion Turbine
Cu	Copper
DAFOR	Derating Adjusted Forced Outage Rate
dc	Direct current
DCF	Discounted Cash Flow
DG1	Decision Gate 1
DG2	Decision Gate 2

Abbreviation	Definition
DG3	Decision Gate 3
DGPS	Differential Global Positioning Systems
DOF	Department of Finance
DP	Dynamic Positioning
DSM	Demand Side Management
DTS	Distributed Temperature Sensing
DWA	Double Wire Armour
EIS	Environmental Impact Statement
EMF	Electromagnetic Force
EPCM	Engineer, Procure, Construct and Manage
EPP	Emergency Preparedness Plan
ERO	Electric Reliability Organization
ESCR	Equivalent Short Circuit Ratio
ESP	Electrostatic Precipitators
EUE	Expected Unserved Energy
FAST	Fast Actions for Secure Transmission
FD	Forced Draft
FEU	Forced Energy Unavailability
FGD	Flue Gas Desulphurization (i.e. Scrubbers)
FO	Fibre Optic Cable
FOR	Forced Outage Rates
GDP	Gross Domestic Product
GE	General Electric
GHG	Greenhouse Gas
GI	Gull Island
GLC	Ground Level Concentration
GS	Generating Station
GTRPMTF	Generation and Transmission Reliability Planning Models Task Force
GWAC	Guaranteed Winter Availability Contract
GWh	Gigawatt Hour
HADD	HarMuskrat Fallsul Alteration Disruption or Destruction of Fish
HDD	Horizontal Directional Drilling
HDPE	High Density Polyethylene Pipe
HEC-RAS	Hydraulic Engineering Centre – River Analysis System
HEP	Hydroelectric Projects
HFO	Heavy Fuel Oil
HQ	Hydro Quebec
HRSG	Heat Recovery Steam Generator

Abbreviation	Definition
HTGS	Holyrood Thermal Generating Station
HVdc	High Voltage Direct Current
IEA	International Energy Agency
ICESIM	Ice Simulation Model
ID	Induced Draft
IDC	Interest During Construction
IGBT	Insulated Gate Bipolar Transistor
IPP	Independent Power Producer
IRR	Internal Rate of Return
km	Kilometre
kV	Kilovolt
kW	Kilowatt
kWh	Kilowatt hour
LCC	Line Commutated Converter
LCG	Lassalle Consulting Group
LCP	Lower Churchill Project
LHV	Lower Heating Value
LIFO	Limestone Injection Forced Oxidation
LIL	Labrador-Island HVdc Transmission Link
LNG	Liquefied Natural Gas
LOLE	Loss of Load Expectation
LOLH	Loss of Load Hours
LOLP	Loss of Load Probability
MF	Muskrat Falls
MFL	Maximum Flood Level
MHI	Manitoba Hydro International Ltd.
MI	Mass Impregnated
WACC	Weighted Average Cost of Capital
WFGD	Wet Flue Gas Desulfurization
MVAr	Mega Volt Ampere Reactive
MW	Megawatt
MWh	Megawatt Hour
NERC	North American Electric Reliability Corporation
NLH	Newfoundland and Labrador Hydro
NOx	Nitrous Oxide
NP	Newfoundland Power
NPCC	Northeast Power Coordinating Council, Inc.
NPV	Net Present Value

Abbreviation	Definition
NUG	Non-Utility Generator
OASIS	Open Access Same Time Information Systems
O&M	Operating and Maintenance
PDI	Personal Disposable Income
PE	Polyethylene
PEACE	Plant Engineering and Cost Estimator
PLF	Planning Load Forecast
PM	Particulate Matter related to the size of the particle
PM10	Particulate Matter 10 micrometers or less
PM2.5	Particulate Matter 2.5 micrometers or less
PMF	Probable Maximum Flood
PMP	Probable Maximum Precipitation
PMSP	Probable Maximum Snow Pack
PPA	Power Purchase Agreement
PPI	Producer Price Index
PSSE	Power System Simulator for Engineering
PTI	Power Technologies Inc.
pu	Per Unit
RCC	Roller Compacted Concrete
RFC	Reliability First Corporation
RFI	Request for Information
RFP	Request for Proposal
ROV	Remotely Operated Vehicle
SCFF	Self-contained Fluid-filled
SCR	Selective Catalytic Reduction
SEU	Scheduled Energy Unavailability
SFC	Static Frequency Converter
SGE Acres	Hatch (formerly SGE Acres)
SNCR	Selective Non-Catalytic Reduction
SOBI	Strait of Belle Isle
SOx	Sulphur emissions
SSARR	Streamflow Synthesis and Reservoir Regulation
TLC	Telecommunication
TWh	Terawatt Hour
UC	Upper Churchill
USACE	US Army Corps of Engineers
VAr	Volt Ampere Reactive

Abbreviation	Definition
V, kV	Volts, kilovolts
VSC	Voltage Source Converter
WBS	Work Breakdown Structure

1 Load Forecast

Report by: C. Kellas

Newfoundland is Canada's easternmost province with a relatively small population of half a million residents. The Newfoundland economy has gone through some difficult times in the 1990's with the closure of the cod fishery and many people seeking out-of-province employment opportunities. Since 2000, the economy has improved significantly with the expansion of the off-shore oil fields and recovery of the inshore fishery. However, the pulp and paper industry has fallen on hard times, which has caused two of the three major mills to close. The economic hardship and recovery are reflected in the historical economic and demographic data.[1]

Newfoundland and Labrador Hydro (NLH) is a crown corporation and subsidiary of Nalcor Energy. NLH has 1,637 MW of installed generating capacity and is the primary generator of electricity in Newfoundland. NLH owns and operates most of the existing generation facilities on the island, but other utility generation and non-utility generation facilities exist and are included in the total interconnected system capabilities that are being reviewed in this project.

NLH currently serves three large industrial customers (a pulp and paper mill in Corner Brook, an oil refinery at Come-by-Chance and a copper mine at Duck Pond) and about 10% of the domestic and general service customers, who generally live in remote or rural areas. NLH also sells power at a wholesale rate to Newfoundland Power (NP), which is the dominant electric retailer on the island. NP is a privately owned electrical utility that distributes electricity to the vast majority (90%) of the island's domestic and general service customers. Since NP services the bulk of the domestic and general service customers, they retain most of the customer billing data. NP conducts customer surveys and load research analysis for their customer base. NP also provides NLH with summarized monthly sales by customer class for the domestic and general service sectors. The conservation demand management (CDM) programs are jointly designed by NP and NLH staff. These programs are available to all Newfoundland customers.

NLH is responsible for producing the long term forecast to assess future generation requirements on the island. NLH does not have access to the majority of customers on the island, which limits the company's ability to conduct detailed end-use analysis of customer billing information. NLH periodically conducts customer survey research of their domestic customer base. In 2010, NLH completed a survey of their domestic customers. In 2006, NLH conducted a two year load research program to measure hourly loads in the domestic and general service sectors.

This review examines the 2010 Planning Load Forecast (PLF) that was prepared by the Market Analysis Section of the NLH System Planning Department. This assessment and report was developed using information obtained during meetings with NLH staff as well as through formal Requests for Information (RFI). The load forecast analysis used information provided in Exhibits 1, 27, 45, 46, 58, 62, 63, 64, and 103, as well as responses to MHI-Nalcor 92 and Nalcor's Final Submission. The material was sufficiently detailed to allow a thorough review and the findings were developed based on complete data provided by NLH.

[1] Exhibit 45 Rev.1, Nalcor, "Key Regression Equations"

The domestic and general service forecasts are based on econometric equations that are estimated over the 1969-2008 period. The industrial sector forecast is prepared through direct customer contact to assess power requirements on a case-by-case basis. The load forecast is prepared using an iterative process in which the initial forecast is passed through a process of generation expansion, capital, financial and revenue requirement models to determine the future marginal electricity price. The forecast is recalculated on updated marginal price and commercial business investment figures, until the updated load forecast does not substantially change the generation expansion sequence and future capital requirements.

For analytical purposes, the 2010 forecast year was replaced with weather-adjusted actual figures so the analysis could be based on the most current data available. The island load forecast is extended over the 2029-2067 period using an extrapolation of the last five forecast (2024-2029) years. This extrapolation is reduced in five to ten year intervals to reflect the maturing market saturation for electric space heat. The extended forecast will only be reviewed for total island energy requirements and the interconnected island system peak demand requirements.

The load forecasting process was evaluated using criteria that examined the reasonableness of the methodologies and assumptions used to prepare the 2010 PLF. Past forecast performance was measured by examining the accuracy of the last ten forecasts prepared by NLH. The 2001 PLF was compared to actual figures for each year from 2001 to 2010; the 2002 PLF was compared to actual figures for each year from 2002 to 2010, etc. In total, 55 different combinations of forecast value and actual year results were analysed to assess forecast accuracy. The accuracy analysis was conducted for the domestic sector, general service sector, industrial sector, line loss sector, total island energy requirements and interconnected system peak demand.

1.1 Domestic Sector

1.1.1 Overview and Methodology

The domestic sector is comprised of the customers served by NP and the rural customers served by NLH. Electric heat growth is the dominant domestic end-use and a significant factor in the overall island load growth[2]. The space heating market is made up of electricity (60%), oil (25%) and wood (15%). Electric heat and non-electric heat customers consume an average of 19,500 kWh and 9,500 kWh, respectively. During 1980-2000, about 70% of new homes installed electric heat. Since 2000, the new home electric heat saturation has reached 85% due to convenience and increasing oil prices.

The domestic forecast is prepared multiplying an average use forecast by the number of customers forecast. The NP portion of the domestic forecast is prepared through the estimation of two regression equations to predict average use and the number of customers. This methodology is used because the domestic sector is relatively homogeneous, which implies that the average use is representative of all customers in the domestic class. Another two equations forecast the penetration rate of electric space heat for new customers and the conversion rate to electric space heat for existing customers. These

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[2] Exhibit 27, Nalcor, "Summary of Newfoundland and Labrador Hydro 2010 Long Term Planning Load Forecast", 2010

equations are used to develop a forecast for the saturation of electric space heat, which is a critical input variable to the NP average use equation.

The NLH portion of the domestic forecast is primarily prepared through the estimation of a regression equation explaining the average use of a rural NLH customer. The average use forecast is multiplied by a NLH customer forecast that is derived from the Department of Finance housing starts forecast.

The regression equations are derived from summarized NP and NLH customer billing data, electricity price data, and economic and demographic data supplied from the Newfoundland Department of Finance and Statistics Canada. Forecast assumptions for economic and demographic variables are prepared by the Department of Finance. The model specification and coefficients for the regression equations are shown in the Forecast Models section 1.10.

1.1.2 Comparison of Historical and Forecast Results

Figure 1 shows that the domestic sector grew rapidly over the 1969-1993 period and remained relatively flat during 1993-1999 due to the economic downturn. Since 1999, the domestic electricity consumption has grown steadily due to increasing levels of housing, income and electric space heat.

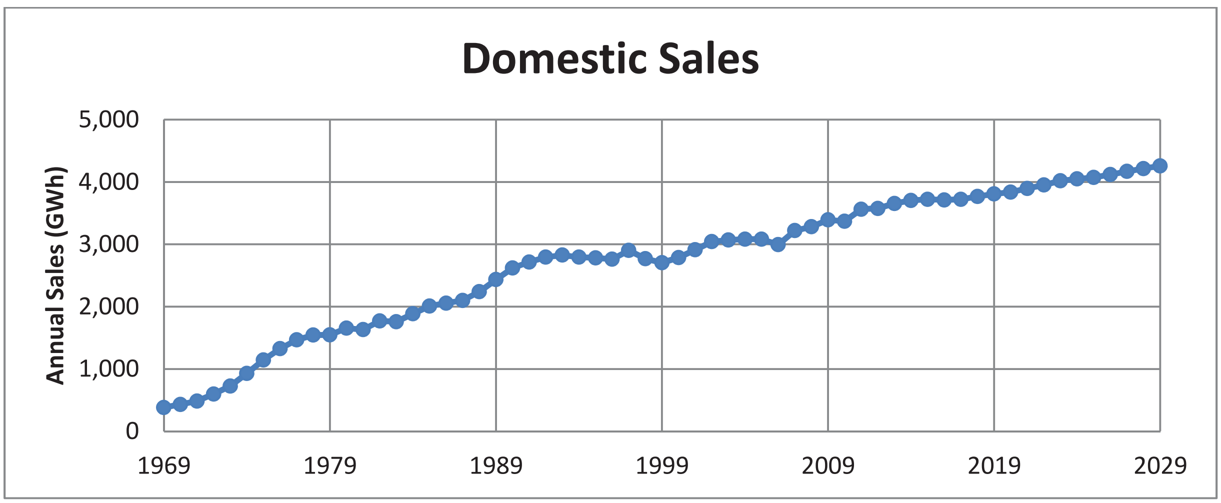

Figure 1: Domestic Energy Sales[3]

Table 1 shows that the domestic electricity forecast increases 38 GWh per year during the forecast period. This growth is 51% lower than the 78 GWh per year experienced in the last 40 years and 39% lower than the 62 GWh experienced in the last decade.

[3] Exhibit 1 - Addendum, Nalcor, "Planning Load Forecast Outline and Tables", and Exhibit 58, Nalcor, "Total Island Interconnected Load"

Table 1: Domestic Energy Growth per Year (GWh)[4]

Domestic Energy Growth Per Year (GWh)		
Last 40 Years	Last 10 Years	2010-2029
78	62	38

The primary components of the domestic forecast are the average use and customer forecasts. Table 2 shows that the average use forecast increases 19 kWh per year over the forecast period, which is 93% lower than the 261 kWh per year experienced in the last forty years and 82% lower than the 106 kWh per year experienced in the last decade. The lower average use forecast is the result of lower electric space heat growth, higher marginal electricity prices and continued efficiency improvement. The electric space heat saturation rate is forecast to increase 0.4% per year during the forecast, which is much lower than the 1.4% increase per year experienced in the last forty years or the 0.8% increase per year experienced in the last decade.

Table 2: Domestic Average Use Growth per Year[5]

Domestic Average Use Growth Per Year (kWh/Customer)		
Last 40 Years	Last 10 Years	2010-2029
261	106	19

Table 3 shows that the customer forecast increases by 2,133 per year. This is 40% below the 3,569 customers per year experienced in the last forty years and 19% below the 2,632 customers per year experienced in the last decade. The lower customer forecast is a result of a lower housing starts forecast provided by the Department of Finance, as shown in the Key Economic Assumptions section 1.7.

Table 3: Domestic Customer Growth per Year[6]

Domestic Customer Growth Per Year		
Last 40 Years	Last 10 Years	2010-2029
3,569	2,632	2,133

[4] MHI derived from Exhibit 1 Addendum, Nalcor, "Planning Load Forecast Outline and Tables", and Exhibit 58, Nalcor, "Total Island Interconnected Load"

[5] MHI derived from Exhibit 45 Rev. 1, Nalcor, "Key Regression Equations"
[6] MHI derived from Exhibit 45 Rev. 1, Nalcor, "Key Regression Equations"

1.1.3 Accuracy and Conclusions

Forecasting an uncertain future is a difficult task. Variation between actual and predicted results must be expected. Experience within the industry and results from Manitoba Hydro[7] and other utilities indicate that a reasonable performance measure for forecast accuracy is to expect a forecast deviation of one percent per year into the future. This means that a ten year old forecast should be within ten percent (plus or minus) of the actual load observed.

Table 4 shows that the domestic forecast meets this requirement because the accuracy level is similar to the age of the forecast (i.e. the number of years ago that the forecast was prepared). Therefore, even though the domestic forecast has consistently under predicted load growth, the forecast has met acceptable levels of accuracy and has performed reasonably well in the past. Based on past forecast performance, lower average use projections, lower customer projections and relatively conservative future assumptions, it is reasonable to assume that the long term domestic forecast will continue to under predict load growth, but at a rate of about one percent per future year.

Table 4: Domestic Energy Forecast Accuracy[8]

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 Accuracy	-1.3%	-2.2%	-3.3%	-3.8%	-4.0%	-4.7%	-5.8%	-6.9%	-7.9%	-10.0%

The main concern is the frequency in which the domestic forecast has under predicted energy consumption. The accuracy analysis compared 55 combinations of forecast value to actual year-end sales. The results showed that in 53 of the 55 cases, the domestic forecast was low. This bias would indicate that the load is growing for reasons not identified in the model (i.e. other end-uses, not just electric space heating) and/or that the assumptions driving the model are consistently conservative. Virtually all growth in the domestic average use model is attributable to electric space heat and other end uses are not specifically identified or forecast to grow within the current modeling framework. The domestic forecast regression models do not have the explanatory power of end-use analysis.

End-use models are based on detailed customer billing and survey analysis. End-use models are calculated using a bottom up approach, meaning that the forecast is calculated by summing up the energy associated with each of the major domestic end-uses. A good end-use forecast would estimate the domestic energy requirements associated with specific end-uses such as: electric space heat, electric water heating, fridges, stoves, washers, dryers, dishwashers, televisions, personal computers and lighting, plus a miscellaneous component to represent all other electrical uses.

[7] www.hydro.mb.ca/regulatory_affairs/electric/gra_2010_2012/Appendix_62.pdf (Pages 55 and 56)
[8] MHI derived from Exhibit 46, Nalcor, "PLF Key Forecast Units for Island Interconnected Systems 2001 - 2010" and Exhibit 64, Nalcor, "Actual NLH Rural Island Interconnected Loads and Customers"

The domestic sector represents about 50% of all electricity sales on the island; therefore the significance of the domestic load makes end-use modeling desirable for this sector. The recommendation to develop an end-use forecasting methodology for the domestic sector is primarily based on the ability of end-use models to quantify load growth by end-use, quantify energy-efficiency by end-use, incorporate new end-uses (e.g. electric cars), improve the design of CDM programs and improve the defensibility of the load forecasting process. Although the additional detail required to prepare an end-use forecasting methodology may likely improve forecast accuracy, increased accuracy is not guaranteed because any forecast is dependent on the accuracy of the assumptions on which it is based.

In summary, the domestic forecast methodology is acceptable, but does not meet the requirement of utility best forecast practice for this sector. The domestic forecast is entirely prepared using econometric modeling techniques. The domestic forecast model is primarily driven by electric space heat. Best utility practices would incorporate end-use modeling techniques into the forecasting process, so that electricity growth can be quantified for all major domestic end-uses of electricity.

1.2 General Service Sector

1.2.1 Overview and Methodology

The general service sector is also comprised of the customers served by NP and the rural customers served by NLH. Electric space heating is the most important component of this sector. The general service forecast is prepared through the estimation of four sub-groups: NP electric heat, NP small non-electric heat, NP large non-electric heat and NLH rural, which is primarily heated by electricity. The NP electric heat group is the most important sector, representing 54% of the total general service sales[9]. The NP electric heat and NLH rural groups are forecast using regression equations that predict total energy consumption. Average use is not forecast because the general service sector is comprised of many different business types (e.g. small industrials, offices, schools, hospitals, grocery stores, retail stores, restaurants, etc.) with significantly different usage patterns. The regression equations are derived from summarized customer billing data and economic data supplied by Statistics Canada, investment data supplied by the Department of Finance and furnace oil price data supplied by PIRA. The model specification and coefficients for the regression equations are shown in the Forecast Models section 1.10.

The NP forecast also consists of small non-electric and large non-electric groups. These groups are assumed to remain at constant levels of 300 GWh and 585 GWh, respectively, throughout the forecast period.[10]

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[9] MHI derived from Exhibit 46, Nalcor, "PLF Key Forecast Units for Island Interconnected Systems 2001 - 2010" and Exhibit 64, Nalcor, "Actual NLH Rural Island Interconnected Loads and Customers"
[10] Exhibit 46, Nalcor, "PLF Key Forecast Units for Island Interconnected Systems 2001-2010"

1.2.2 Comparison of Historical and Forecast Results

Figure 2 shows that the general service sector grew rapidly over the 1970-1990 period and remained relatively flat during the 1990's, as GDP and commercial business investment stalled. Since 1999, the general service load has grown at a steady, slow rate due to increasing levels of construction activity, GDP, commercial business investment and furnace oil prices, which make electric heat more desirable.

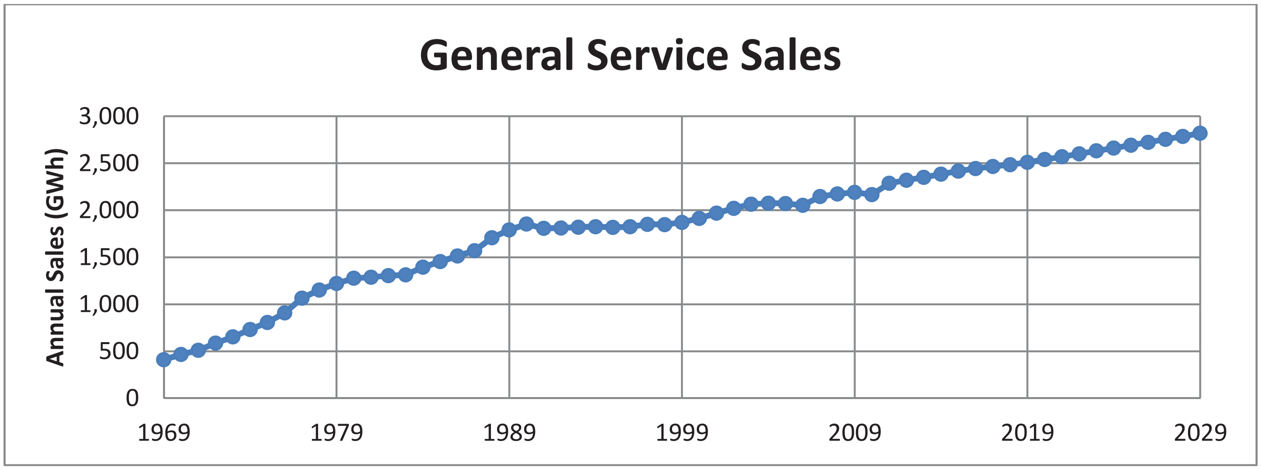

Figure 2: General Service Sales[11]

Table 5 shows that general service electricity consumption is forecast to increase 32 GWh per year. Forecast growth is 27% lower than the 44 GWh per year experienced over the last forty years or 23% higher than growth experienced in the last decade. The general service forecast is primarily based on slower levels of gross domestic product (GDP) growth and higher levels of commercial business investment growth provided by the Department of Finance and are shown in the Key Economic Assumptions section 1.7.

Table 5: General Service Energy Growth per Year (GWh)[12]

General Service Energy Growth per Year (GWh)		
Last 40 Years	Last 10 Years	2010-2029
44	26	32

1.2.3 Accuracy and Conclusions

Table 6 shows that the forecasting methodology for the general service sector has produced remarkably good results. Regression modeling and linear extrapolation techniques have worked extremely well. Implementation of an end-use forecasting model for the general service sector is not recommended at this time because the current models are performing very well and the additional allocation of resources required to implement an end-use methodology could not be justified based

[11] MHI derived from Exhibit 1 Addendum, Nalcor, "Planning Load Forecast Outline and Tables", and Exhibit 58, Nalcor, "Total Island Interconnected Load"
[12] MHI derived from Exhibit 1 Addendum, Nalcor, "Planning Load Forecast Outline and Tables", and Exhibit 58, Nalcor, "Total Island Interconnected Load"

on improvement in forecast accuracy. The complexity and diversity of the building stock make end-use modeling of the general service sector a difficult task. NLH should focus on developing an end-use model for the domestic sector, which represents a larger proportion of the load.

Table 6: General Service Energy Forecast Accuracy[13]

Forecast Accuracy Measured in Percentage of Deviation from the Actual Load										
Years of History	1	2	3	4	5	6	7	8	9	10
General Service Accuracy	-0.1%	0.0%	0.0%	0.1%	0.3%	0.4%	0.4%	1.0%	2.0%	6.0%

In summary, the general service forecast methodology is based on a combination of regression modeling and linear extrapolation techniques that have performed extremely well in the past. The general service forecast has produced accuracy levels within 1 to 2%, as far as eight to nine years into the future. The general service forecasting process is relatively unbiased. Under prediction of actual weather-adjusted energy consumption occurred 24 times and over prediction occurred 31 times of the 55 cases examined. NLH should continue using the current general service forecasting methodology.

1.3 Industrial Sector

1.3.1 Overview and Methodology

The industrial sector consists of only three existing large industrial customers: a pulp and paper mill in Corner Brook, an oil refinery at Come-by-Chance and a copper mine at Duck Pond. Contractual arrangements have been made to supply electric power to the new Vale hydrometallurgical processing plant being constructed at Long Harbour. The industrial forecast is prepared on an individual, case-by-case basis, with direct customer contact concerning future operational plans.

This forecast assumes that the pulp and paper mill and oil refinery will continue at current operational levels throughout the forecast horizon. The copper mine is forecast to cease operation in 2013. The load forecast includes new load based on contractual arrangements with Vale, which will be staged in over the 2013-2015 period. The industrial forecast does not include any further large customer additions throughout the forecast horizon. Conversely, the long term forecast does not include a probability for the potential closure of industrial customers.

The principal risk in the forecast is the long term viability of the pulp and paper mill. If the Corner Brook mill closes, there will be a large gap created between excess supply and demand. In the long

[13] MHI derived from Exhibit 46, Nalcor, "PLF Key Forecast Units for Island Interconnected Systems 2001 - 2010" and Exhibit 64, Nalcor, "Actual NLH Rural Island Interconnected Loads and Customers"

term, this gap will diminish as new industrial loads potentially locate on the island throughout the forecast horizon. The original load forecast covers a twenty year period and is extended out to 2067. Unforeseen events can and likely will happen during the forecast period and beyond.

1.3.2 Comparison of Historical and Forecast Results

Figure 3 shows that the industrial sector grew rapidly over the 1975-1984 period and fluctuated, but remained relatively constant throughout 1984-2005. Since 2005, the industrial load has declined sharply due to the closure of two Abitibi pulp and paper mills at Stephenville (2006) and at Grand Falls (2009).

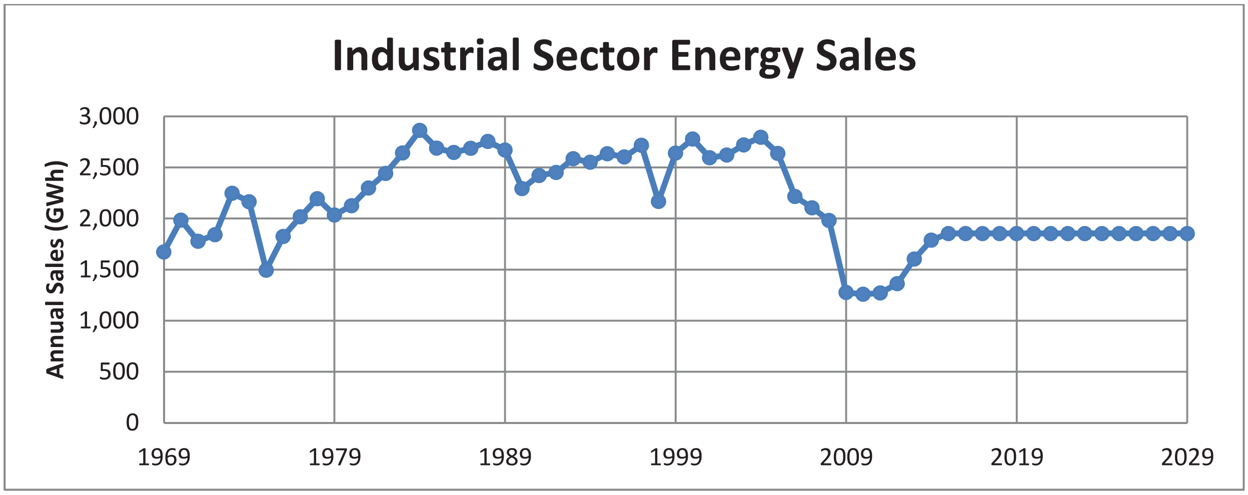

Figure 3: Industrial Sector Energy Sales[14]

Table 7 shows that the industrial forecast predicts that electricity consumption will grow 31 GWh per year. This growth is specifically associated with the Vale hydrometallurgical load coming online during the 2013-2015 period. The load remains constant after 2015. Industrial consumption decreased an average of 152 GWh per year in the last decade, primarily due to pulp and paper mill closures.

Table 7: Industrial Energy Growth per Year (GWh)[15]

Industrial Energy Growth Per Year (GWh)		
Last 40 Years	Last 10 Years	2010-2029
-18	-152	31

1.3.3 Accuracy and Conclusions

Table 8 shows that the industrial forecast has consistently over predicted load growth by a considerable amount, resulting from unanticipated mill closures.

[14] Exhibit 1 Addendum, Nalcor, "Planning Load Forecast Outline and Tables", and Exhibit 58, Nalcor, "Total Island Interconnected Load"
[15] MHI derived from Exhibit 1 Addendum, Nalcor, "Planning Load Forecast Outline and Tables", and Exhibit 58, Nalcor, "Total Island Interconnected Load"

Table 8: Industrial Energy Forecast Accuracy[16]

Forecast Accuracy Measured in Percentage of Deviation from the Actual Load										
Years of History	1	2	3	4	5	6	7	8	9	10
Industrial	5%	14%	27%	37%	50%	67%	76%	92%	119%	124%

The customer specific methodology used to prepare the industrial forecast is reasonable, but in hindsight, the assumption of continued operation of the pulp and paper industry was too optimistic and has caused problems that have affected overall forecast accuracy. A method to potentially improve the industrial forecast accuracy could be to assign a probability of operation to the large industrial loads. This probability could increase or decrease over time, depending on the likelihood of expansion or contraction of business operations in the future. However, this may be difficult to implement given the limited size of the industrial customer base.

If the pulp and paper facility at Corner Brook stays operational throughout the forecast horizon, the industrial forecast should be about 90 GWh low, because the ongoing customer consultation process has recently upgraded consumption estimates of the Vale hydrometallurgical processing plant by 90 GWh. In the longer term, the industrial forecast runs the risk of being too low because no new industrial loads are forecast for the entire review period to 2067. Any new industrial load would increase industrial consumption above forecast levels.

If the Corner Brook operation closes, then the load forecast will be too high and the forecast errors of the past will be replicated. In the long term, it is likely that new potential industrial loads will eventually replace the load lost due to a Corner Brook closure. Any scenario that includes the closure of the pulp and paper mill will have to be evaluated in a sensitivity analysis because the facility is the island's largest customer and consumes a significant portion of all the electric generation on the island. The amount of variability due to potential industrial load changes is high and impacts the results of the cumulative present worth (CPW) analysis.

1.4 Line Losses and Other Loads

1.4.1 Overview and Methodology

This sector includes street lighting, distribution losses, transmission losses and company use. It represents 8% of the total island energy requirements.[17] Transmission and distribution losses comprise the majority of this sector's load. These losses increase proportionally as sales in the domestic, general service and industrial sectors increase. Distribution and transmission losses are forecast as a

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[16] MHI derived from Exhibit 46, Nalcor, "PLF Key Forecast Units for Island Interconnected Systems 2001 - 2010"
[17] MHI derived from Exhibit 58, Nalcor, "Total Island Interconnected Load"

percentage of sales. Street lighting and company use are assumed to remain constant throughout the forecast period.

1.4.2 Comparison of Historical and Forecast Results

Figure 4 shows that the loss sector grew slowly in the 1989-2005 period. Actual line losses will vary based on the frequency and severity of outages and the proximity of generation to load centers. It should be noted that the forecast for transmission line losses is based on historical loss percentages.

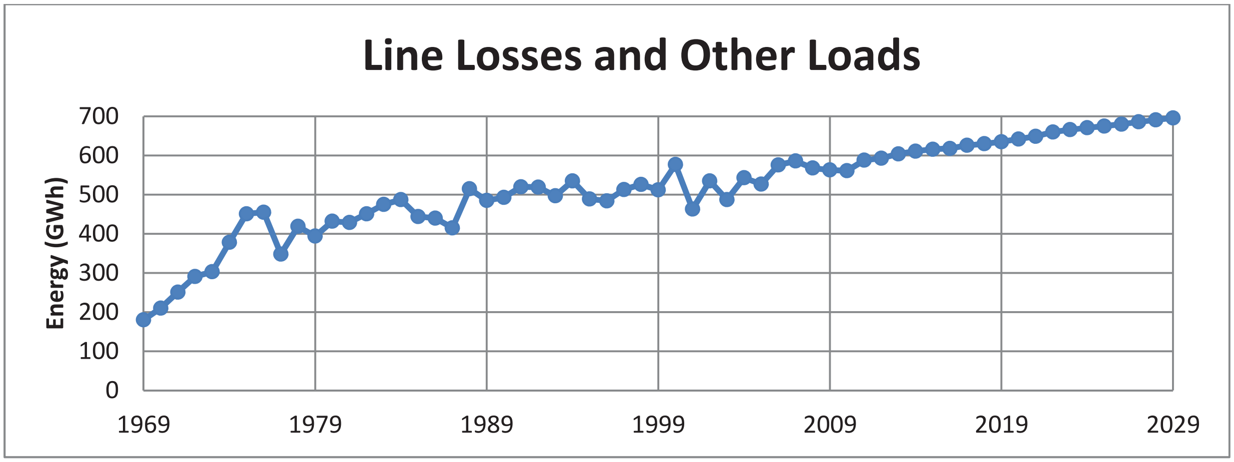

Figure 4: Other Load Forecast[18]

Table 9 shows that this sector is forecast to increase 6 GWh per year. Forecast growth is similar to the growth experienced in the last forty years.

Table 9: Line Losses & Other Loads Growth per Year (GWh)[19]

Line Losses & Other Loads Growth Per Year (GWh)		
Last 40 Years	Last 10 Years	2010-2029
9	0	6

1.4.3 Accuracy and Conclusions

Table 10 shows that the forecast methodology used to prepare the line losses and other loads forecast has produced reasonable results. Forecast accuracy results vary due to fluctuations in actual year-to-year line losses.

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[18] MHI derived from Exhibit 1 Addendum, Nalcor, "Planning Load Forecast Outline and Tables", and Exhibit 58, Nalcor, "Total Island Interconnected Load"
[19] MHI derived from Exhibit 1 Addendum, Nalcor, "Planning Load Forecast Outline and Tables", and Exhibit 58, Nalcor, "Total Island Interconnected Load"

Table 10: Line Losses & Other Loads Energy Forecast Accuracy[20]

Forecast Accuracy Measured in Percentage of Deviation from the Actual Load										
Years of History	1	2	3	4	5	6	7	8	9	10
Line Losses & Other Loads	-2.5%	-3.8%	-4.5%	-6.2%	-6.6%	-6.7%	-5.6%	-4.6%	-3.4%	-4.1%

1.5 Total Island Energy Requirements

1.5.1 Overview and Methodology

The total island energy requirements forecast is calculated by summing the domestic, general service, industrial and line loss forecasts.

1.5.2 Comparison of Historical and Forecast Results

Figure 5 shows that the domestic and general sectors have grown steadily throughout the historical period, except for the economic slowdown of the 1990's. Figure 5 also shows the decline in the industrial sector due to the pulp and paper mill closures in 2006 and 2009. Steady growth is expected in the domestic and general service sales. The Vale expansion stimulates growth in the 2013-2015 period.

[20] MHI derived from Exhibit 46, Nalcor, "PLF Key Forecast Units for Island Interconnected Systems 2001 - 2010", Exhibit 64, Nalcor, "Actual NLH Rural Island Interconnected Loads and Customers", and Exhibit 103, Nalcor, "Island Interconnected Requirments – Actual and Forecast"

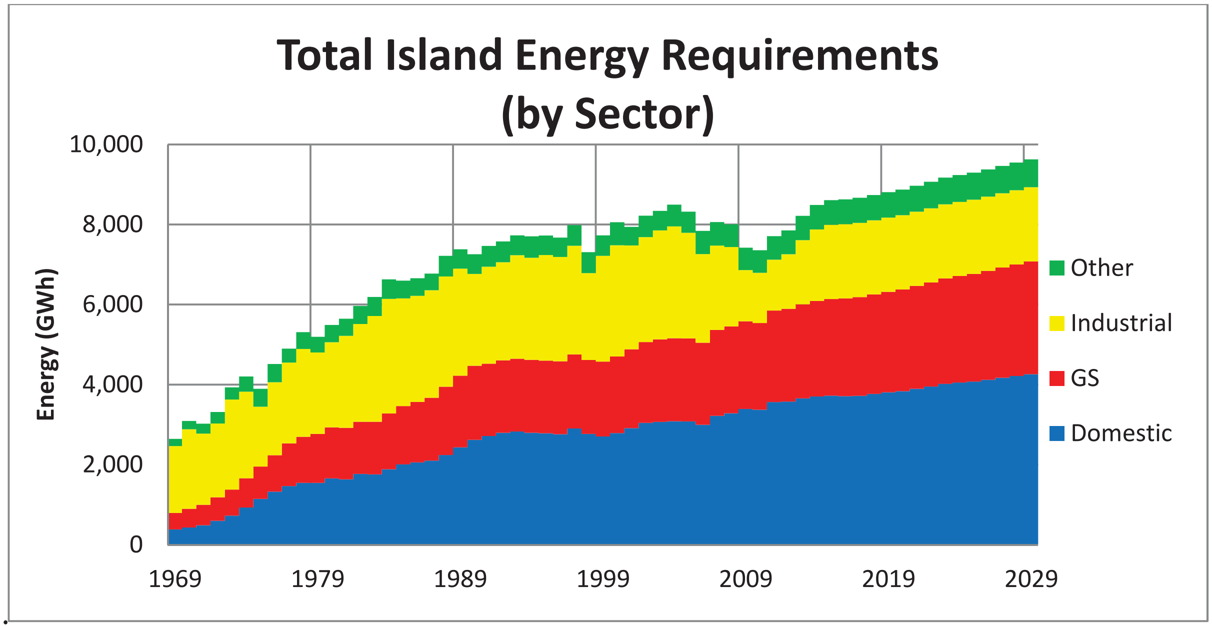

Figure 5: Total Island Energy Forecast by Sector[21]

Figure 6 shows the total island energy requirements forecast over the extended period of time. The extended forecast (2029-2067) is based on an extrapolation of the last five years (2024-2029) of the 2010 Planning Load Forecast.

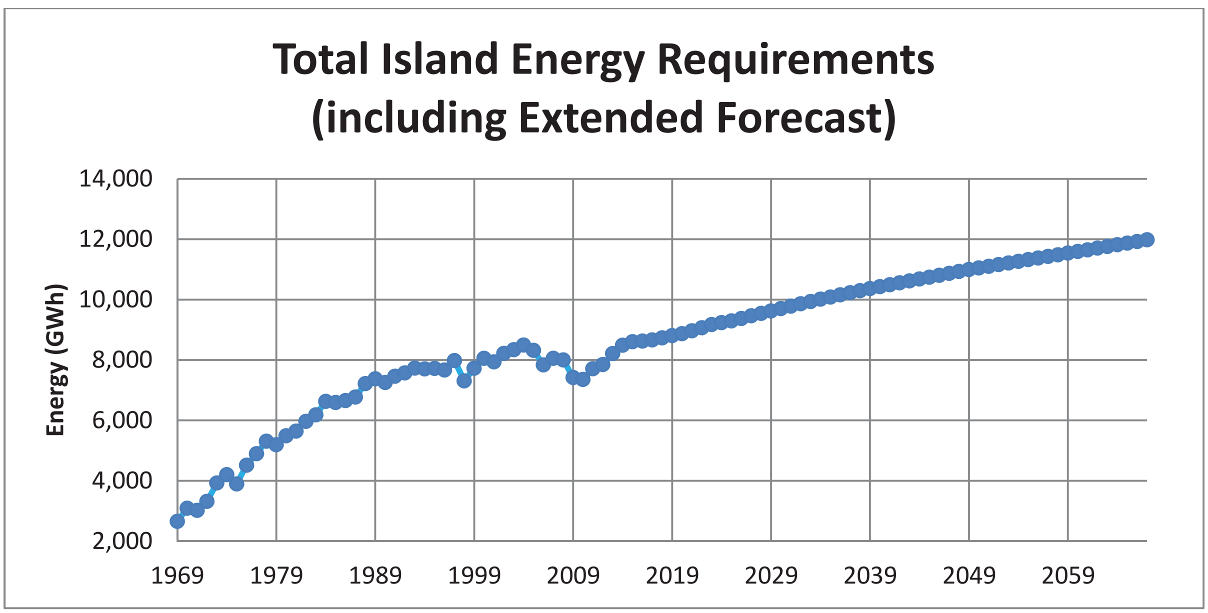

Figure 6: Total Island Energy Requirements to 2067[22]

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[21] MHI derived from Exhibit 1 Addendum, Nalcor, "Planning Load Forecast Outline and Tables", and Exhibit 58, Nalcor, "Total Island Interconnected Load"

[22] Exhibit 1 Addendum, Nalcor, "Planning Load Forecast Outline and Tables", and Exhibit 58, Nalcor, "Total Island Interconnected Load"

Table 11 shows that the total island energy requirements decreased 63 GWh per year in the last decade. Total island energy requirements are forecast to increase 106 GWh per year in the 2010-2029 forecast period, which is 6% lower than the 113 GWh growth experienced in the last forty years. The lower load growth is primarily due to the lower domestic energy forecast. Total island energy requirements are forecast to increase 62 GWh per year over the extended period. The extended load growth is 45% lower than the growth experienced in the last forty years and 42% lower than the growth expected in the first forecast period (2010-2029). The lower growth in the extended period is a result of no industrial load increase and limited electric space heating growth in the domestic and general service sectors.

Table 11: Total Island Energy Growth per Year (GWh)[23]

Total Island Energy Growth Per Year (GWh)			
Last 40 Years	Last 10 Years	2010-2029	2029-2067
113	-63	106	62

1.5.3 Accuracy and Conclusions

Table 12 shows that in the last ten years, the total island energy requirements forecast has significantly over predicted load growth. The vast majority of the forecast deviation can be associated with the industrial forecast. Previous load forecasts assumed that the pulp and paper industry would continue operations at normal energy consumption levels, without any mill closures. The loss of load associated with the two pulp and paper mills caused an adverse effect on the overall forecast accuracy results.

Table 12: Total Island Energy Forecast Accuracy[24]

Forecast Accuracy Measured in Percentage of Deviation from the Actual Load										
Years of History	1	2	3	4	5	6	7	8	9	10
Island Energy	0.4%	1.9%	3.7%	5.5%	7.9%	10.6%	11.4%	13.3%	16.6%	17.4%

Table 13 shows that the total island energy requirements forecast would have been exceptionally accurate, if the timing and magnitude of mill closures were accurately predicted in the previous load forecasts. For the purpose of this analysis, load forecasts prepared before 2006 were reduced by a maximum of 1,100 GWh and load forecasts prepared from 2006-2009 were reduced by a maximum of 600 GWh.

[23] MHI derived from Exhibit 1 Addendum, Nalcor, “Planning Load Forecast Outline and Tables”, and Exhibit 58, Nalcor, “Total Island Interconnected Load”
[24] MHI derived from Exhibit 103, Nalcor, “Island Interconnected Requirments – Actual and Forecast”

Table 13: Total Island Energy Forecast Accuracy Adjusting for Mill Closures[25]

Forecast Accuracy Measured in Percentage of Deviation from the Actual Load										
Years of History	1	2	3	4	5	6	7	8	9	10
Island Energy	-1.2%	-1.4%	-0.8%	-0.6%	-0.3%	1.0%	1.0%	1.5%	2.0%	2.9%

1.6 System Peak

1.6.1 Overview and Methodology

The system peak is the maximum hourly demand placed on the interconnected island system. This maximum load is usually reached at 5:00-6:00 PM on a very cold winter day. The interconnected system peak demand forecast is prepared by estimating four peak demand forecast sub-groups: NP peak demand, NLH rural peak demand, industrial demand and NLH transmission peak demand.

The NP peak demand is the most important component of the peak forecast and is estimated using a regression equation. The model specification and coefficients for the regression equation is shown in the Forecast Models section 1.10. Since the NP peak forecasting methodology is prepared separately (i.e. separate regression equation) from the NP sales forecast, an adjustment is made to the NP peak forecast to ensure that changes to the NP load factor occur in a smooth and consistent basis. The results from the NP forecasting model were increased by 2.5 MW per year for each forecast year, which translates to a 50 MW increase over the twenty year forecast. This adjustment is based on the assumption that peak efficiency improvements will be 30% more difficult to achieve in the future because the most cost-effective improvements have already been done.

The NLH rural peak demand, industrial peak demand and NLH transmission peak demand forecasts are prepared by applying historical coincident load factors to the energy consumption forecast associated with each of these groups. The interconnected system peak demand forecast is prepared by adding the four peak forecasts together.

1.6.2 Comparison of Historical and Forecast Results

Figure 7 shows that the interconnected island peak demand grew rapidly over the 1970-1990 period as the NP electric heat saturation rate increased from 4% to 48%. The peak remained relatively constant throughout the 1990's as electric heat growth was offset by economic stagnation. When the economy recovered, the peak started to grow again, until the two mill closures in 2006 and 2009.

Figure 7 also shows that the NP peak forecast is the most significant (80%) contributor to the interconnected island system peak forecast and has accounted for almost all of the peak load growth

[25] MHI derived from Exhibit 103, Nalcor, "Island Interconnected Requirments – Actual and Forecast" and includes two plant closure assumptions

since 1999. The vast majority of the peak load growth (excluding the Vale expansion), is expected to come from the NP service area.

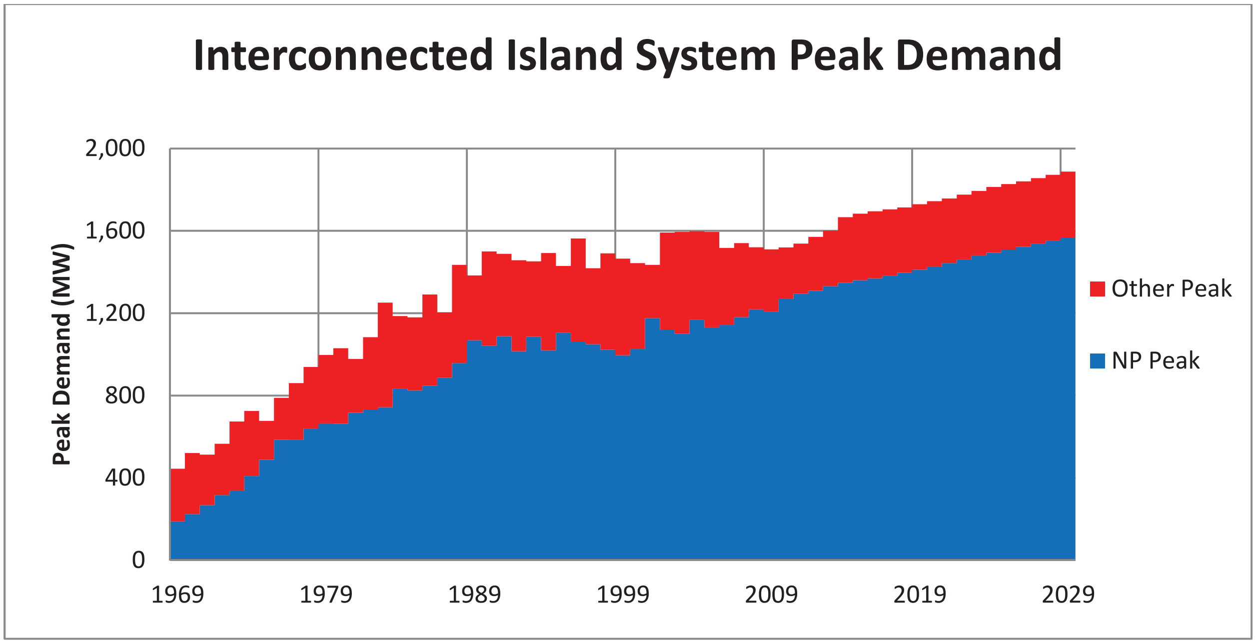

Figure 7: Interconnected Island Peak Demand[26]

Figure 8 shows the interconnected island peak forecast over the extended period of time. The extended forecast (2029-2067) is based on an extrapolation of the last five years (2024-2029) of the 2010 Planning Load Forecast.

[26] Exhibit 1, Nalcor, "NLH 2010 Planning Load Forecast (PLF) for the Island Interconnected System", Exhibit 45 – Rev. 1, Nalcor, "Key Regression Equations" and Response to RFI MHI-Nalcor-92

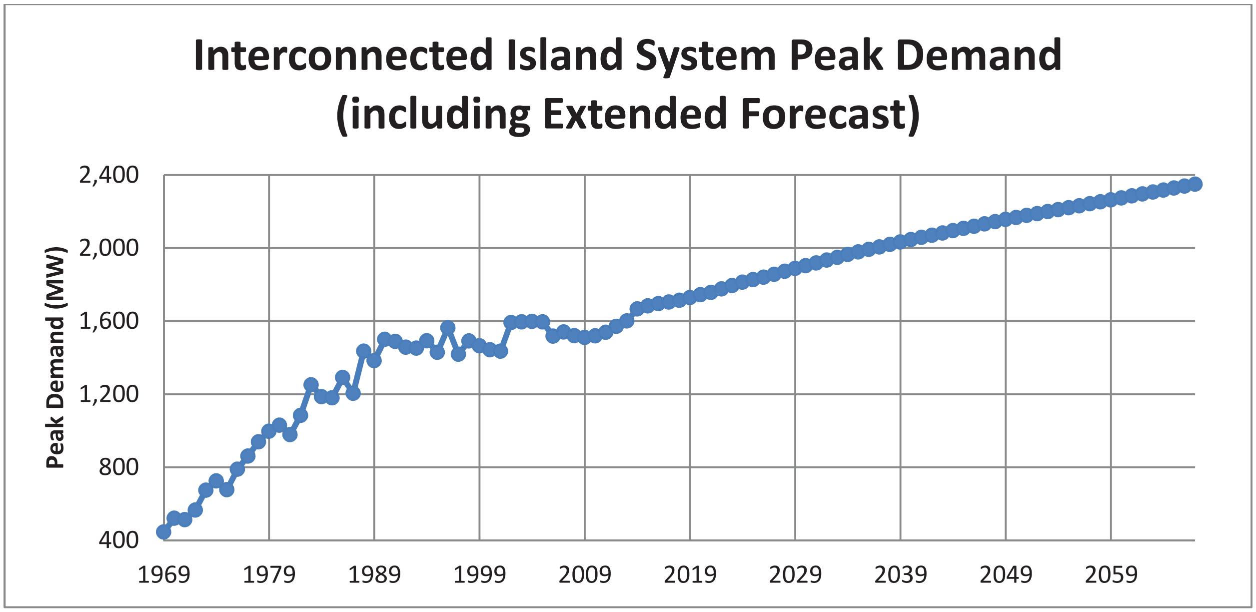

Figure 8: Interconnected Island Peak Demand to 2067[27]

Table 14 shows that the interconnected island peak load is forecast to increase 20 MW per year in the 2010-2029 forecast period. This growth is 20% lower than the 25 MW per year experienced in the last forty years. The forecast drops to 12 MW per year in the extended forecast period, which is 52% lower than the growth experienced in the last forty years.

Table 14: Interconnected System Peak Demand Growth Per Year (MW)[28]

Interconnected System Peak Demand Growth Per Year (MW)			
Last 40 Years	Last 10 Years	2010-2029	2029-2067
25	7	20	12

1.6.3 Accuracy and Conclusions

Table 15 shows that in the last ten years, the NP system peak demand forecast has performed exceptionally well. The "other" peak category includes peak demands associated with the NLH rural system, the NLH industrial customers and the NLH transmission system. The "other" peak and interconnected island peak forecasts have been adversely affected by the pulp and paper mill closures.

[27] Exhibit 1, Nalcor, "NLH 2010 Planning Load Forecast (PLF) for the Island Interconnected System", and Response to RFI MHI-Nalcor-92

[28] MHI derived from Exhibit 1, Nalcor, "NLH 2010 Planning Load Forecast (PLF) for the Island Interconnected System", and Response to RFI MHI-Nalcor-92

Table 15: Interconnected System Peak Demand Forecast Accuracy[29]

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%	0.7%	1.0%	0.6%	1.0%	1.2%	1.3%	0.6%	0.2%	2.5%
Other Peak	-3.5%	-0.5%	5.3%	11.3%	15.7%	25.8%	28.1%	37.1%	43.8%	73.7%
Island Peak	0.6%	0.3%	1.8%	2.8%	4.1%	6.4%	6.8%	8.0%	8.6%	15.3%

Although the regression-based peak forecasting methodology has performed very well in the past, there is a possibility that continuation of this methodology may lead to under forecasting the peak in the future.

The electric space heat end-use has a very low load factor (probably in the range of 35-40% in Newfoundland), so the system load factor should decrease as electric space heating represents a larger proportion of the total island energy requirements. Since 1990, the overall system load factor has changed very little, fluctuating around 60%, even though the number of electric space heating customers has risen dramatically and the high load factor industrial load has declined sharply.

The peak forecasting adjustment assumes that the rate of technological change will continue at a rate of 30% lower in the future. This may not be enough of a reduction. If future efficiency gains from the existing building stock shell improvements (e.g. insulation upgrades, EE windows, caulking, etc.) become even more difficult to achieve, then the rate of future technological change could diminish more than 30%. This would have the effect of increasing the peak forecast (i.e. technological improvements reduce peak requirements). The key point is that the continued addition of electric space heating load should have the effect of lowering the future system load factor more than the current forecasted level of 58%.

The main concern with this methodology is that the system peak is being calculated separately from the energy portion of the forecast. This makes it necessary to calculate adjustments to the peak in order to ensure consistency with the energy growth and produce a smooth load factor for the island. The system peak forecasting methodology could be improved by incorporating domestic, general service, industrial and end-use (e.g. space heating) load research information into the forecasting process to develop an integrated energy and peak forecasting methodology. NLH staff should partner with Newfoundland Power to develop a coordinated load research program that is designed to develop load shape information by sector and by end-use. Sector or end-use energy forecasts could be distributed on an hourly basis throughout the year, using the hourly load shape profiles developed from the load research information. These hourly load forecasts could then be added together to produce an hourly forecast model for the interconnected system.

[29] MHI derived from Exhibit 46, Nalcor, "PLF Key Forecast Units for Island Interconnected Systems 2001 - 2010", and Exhibit 103, Nalcor, "Island Interconnected Requirments – Actual and Forecast"

1.7 Key Economic Assumptions

Key economic and demographic assumptions provided by the Department of Finance (DOF) form the basis on which the domestic and general service forecasts are developed. A regression-based forecast can only be as good as the assumptions on which they are developed.

Table 16 shows that most of the key factors (i.e. income, population, housing, GDP) are assumed to grow at a significantly lower rate than experienced over the last ten or forty years. Using the personal disposable income (PDI) variable as an example, the line entitled “Forecast/Last 10” is derived by dividing the PDI Forecast value ($118) by the PDI Last 10 value ($241), which equals 49%. Thus, the forecast is assuming that PDI will grow at a much slower rate (49%) than it has in the last ten years.

The forecast assumptions of PDI, income, population and housing are all used in the domestic forecast models and contribute to the relatively conservative domestic forecast. The forecast assumption of GDP and commercial business investment are used in the general service forecast models and produce a good forecast.

Table 16: Key Economic and Demographic Assumptions[30]

History	Personal Disposal Income 2002$	Personal Income 2002$	Pop.	Housing Starts	Adjusted GDP 2002$	Commercial Business Investment 2002$
Last 10 Years	$241	$269	-2,443	2,467	$259	$340
Last 40 Years	$181	$235	-344	2,937	$233	$290
Forecast	$118	$147	-110	2,275	$151	$425
Forecast/Last 10	49%	55%	5%	92%	58%	125%
Forecast/Last 40	65%	62%	32%	77%	65%	147%

1.8 Conservation in the Load Forecast

It should be noted that the domestic forecast does not include any specific, exogenous adjustment for specific Conservation Demand Management (CDM) programs. The NLH method of capturing and estimating CDM effects is through the technological change variable contained in the regression equations.

For the NP domestic sector the technological change variable has a -35.37 coefficient, see the Forecast Models section 1.10. This means that the average use is forecast to decline (35.37*20) 707 kWh per

[30] MHI derived from Exhibit 45 Rev. 1, Nalcor, “Key Regression Equation”

customer over the 2010-2029 forecast period. When this figure is multiplied by the NP number of customers, the load forecast includes (707*251,131 customers) 178 GWh due to domestic CDM effects.

The NP general service forecast also captures CDM effects through the estimation of a technological change variable that has a -10.52 coefficient, as shown in the Forecast Model section 1.10. This means that the general service electricity consumption will decline (10.52*20) 210 GWh over the forecast period.

The industrial sector does not include any specific adjustment for CDM. The total sales forecast includes 388 GWh of load reduction for CDM effects. Assuming that system losses average 8%, the total island energy requirements forecast inherently includes 419 GWh of load reduction, which represents 20% of the total energy growth over the forecast period.

1.9 Comparison to Other Utilities

Table 17 was derived from reviewing load forecasts of Canadian electric utilities that were available on the web. Utilities may perform some of these tasks, but they were not observed in the forecast report. This is not intended to be a complete and exhaustive comparison, rather it is meant to provide some insight into the data collection, analysis and forecast methodologies that are used by other Canadian utilities.

The two key points to be made are that other utilities use end-use models to prepare the domestic (residential) forecast and hourly load shape modeling to prepare the peak forecast.

Table 17: Forecast Methods Used by Other Canadian Utilities

FUNCTIONS PERFORMED	RESIDENTIAL				COMMERCIAL				INDUSTRIAL			
	NLH	ON	MB	BC	NLH	ON	MB	BC	NLH	ON	MB	BC
Customer Billing Data	x	x	x	x	x	x	x	x	x	x	x	x
Economic/Price Data	x	x	x	x	x	x	x	x		x	x	x
Demographic Data	x	x	x	x	x	x	x	x		x	x	
Weather Data	x	x	x	x	x	x	x	x	x	x	x	x
Business Type Coding					x	x	x	x	x	x	x	x
Customer Survey Data	x	x	x	x		x	x	x		x		
Appliance/End-Use Data	x	x	x	x		x		x		x		
Commercial Floor Space						x		x				
Industrial Output										x		x
Load Research Data	x	x	x	x	x	x	x	x	x	x	x	x
Load Shape Data		x	x	x		x	x	x	x	x	x	x
Regression Model	x	x	x	x	x	x	x	x		x		x
End-Use Model		x	x	x		x		x		x		
Weather Adjustment Model	x	x	x	x	x	x	x	x		x	x	x
Hourly Load Shape Model		x	x	x		x	x	x	x	x	x	x

1.10 Forecast Models

1.10.1 NP Domestic Average Use Model

This model is the most important component of the domestic forecast. This model is based on the market share of electric heat (percentage of customers using electric space heat), degree days heating, marginal price of electricity, disposable income per customer and the population of Newfoundland. The regression has an R-squared of 99.8%. The R-squared measures the goodness of fit or the percentage of total variation explained by the model. The equation takes the following form:

Y= (3.072308*X1) + (7963.467*X2) + (-524.7547*X3) + (0.064911*X4) + (-35.36781*X5) + (0.008005*X6) + (-617.9116*X7)

Y=Domestic Average Use per Customer in the NP Service Area
X1=Domestic Market Share of Electric Heat *Degree Days Heating
X2=Domestic Market Share of Electric Heat
X3=Domestic Marginal Price of Electricity in the Previous Year (t-1)
X4=Personal Disposable Income per Customer in $2002
X5=Technological Change (<1981=0, 1981=1 increasing by 1 each year, 2010=30)
X6=Population of Newfoundland
X7=Recession Dummy for 1982 (1982=1, otherwise=0)

1.10.2 NP Domestic Customer Additions Model

This model is based on housing starts and personal income per customer. This regression has an R-squared of 93.4%. The equation takes the following form:

Y= (0.480831*X1) + (0.037441*X2) + (3802.905*X3) + (-1768.742*X4) + (-364.1837*X5) + -2029.571

Y=Number of Domestic Customer Additions in the NP Service Area
X1=Housing Starts & Completions
X2=Personal Income per Customer in $2002
X3=Dummy Variable (1972=1, otherwise=0)
X4=Dummy Variable (1976=1, otherwise=0)
X5=Economy Shift Change Variable (<1995=0, 1995 and on=1)

It should be noted that this equation is not as significant as the average use equation because a large variance of 1,000 customers would only create a 15 GWh variance to the electricity forecast because each domestic customer has an annual average use of 15,000 kilowatt-hours.

1.10.3 NP Penetration Rate of Electric Heat in New Homes Model

This model is based on the marginal relative price of electricity, the efficiency-adjusted price of furnace oil, the introduction of the rate stabilization plan and the ratio of urban to total housing starts. This equation has an R-squared of 88.5%. The equation takes the following form:

Y= (-0.41036*X1) + (0.016906*X2) + (0.862048*X3) + (1.014481*X4) + (-0.461892*X5) +0.803393

Y=Logit of the NP Penetration Rate of Electricity in New Homes
X1=Marginal Price of Electricity
X2=Efficiency-Adjusted Price of Furnace Oil
X3=Rate Stabilization Plan (<1986=0, 1986 and on=1)
X4=Ratio of Urban Housing Starts
X5=Dummy Variable for 1998-99 (1998=1, 1999=1, otherwise=0)

1.10.4 NP Conversion Rate of Non-electric to Electric Heat in Existing Homes Model

This model is based on the relative price of electricity compared to furnace oil on a gigajoule-equivalent basis and the market share of electric heat. This equation has an R-squared of 78.9%. The historical conversion rate can vary based on the stability in the price of oil. Most customers that converted to electricity, installed baseboards and retained their oil furnace. In effect, these are dual fuel customers that switch to or from oil heat depending on the relative price of oil versus electricity. In summary, new customers are separated into electric/non-electric classes based on the penetration rate and existing customers are separated into electric/non-electric classes based on the conversion rate.

$$Y = (-2.340087*X1) + (-2.650558*X2) + (-1.082214*X3) + (-0.804003*X4) + (0.543954*X5)$$

Y=Logit of the NP Conversion Rate of Non-electric to Electric in Existing Homes
X1=Relative Price of Electricity to Furnace Oil on an Equivalent Basis (GJ)
X2=Market Share of Electric Heat
X3=Dummy Variable for 1997 (1997=1, otherwise=0)
X4=Economy Shift Change Variable (<2000=0, 2000 and on=1)
X5=Moving Average Variable to Adjust Residuals

1.10.5 NLH Domestic Average Use Forecast

This model is based on the market share of electric heat in rural NLH areas, degree days heating, marginal price of electricity, disposable income per customer and the saturation of electric water heating. The regression has an R-squared of 98.1%.The equation takes the following form:

$$Y = (2.12482*X1) + (-181.8509*X2) + (0.127775*X3) + (41.23951*X4) + (-550.6892*X5) + (-385.9454*X6)$$

Y=Domestic Average Use per Customer in the NLH Service Area
X1=Rural NLH Domestic Market Share of Electric Heat *Degree Days Heating (Stephenville)
X2=Domestic Marginal Price of Electricity in the Previous Year (t-1)
X3=Personal Disposable Income per Customer in $2002
X4=Electric Hot Water Saturation Rate
X5=Dummy Variable (1995=1, otherwise=0)
X6=Dummy Variable (1987=1, otherwise=0)

1.10.6 NP General Service Electric Heat Load Model

The electrical energy requirement for NP general service customers with electric heat is forecasted based on gross domestic product, commercial building investment, weather data and furnace oil price data. The regression has an R-squared of 99.9% and all input (explanatory) variables are significant. The equation takes the following form:

Y= (0.021163*X1) + (0.084515*X2) + (0.030751*X3) + (0.639004*X4) + (39.24521*X5) + (31.57073*X6) + (-10.51975*X7) - 400.4815

Y=General Service Electricity Load (GWh) for NP Customers
X1=Gross Domestic Product Adjusted for Outflows in $2002
X2=Commercial Business Investment
X3=Degree Days Heating
X4=Efficiency-Adjusted Furnace Oil Price
X5=Economy Shift Change Variable (<1976=0, 1976 and on=1)
X6=Dummy Variable for 1996 (1996=1, otherwise=0)
X7=Technological Change (<1995=0, 1995=1 increasing by 1 each year, 2010=16)

1.10.7 NLH General Service Forecast

The electrical energy requirement for all NLH general service customers is forecasted based on personal income. The regression has an R-squared of 99.6%. The equation takes the following form:

Y= (0.004164) + (0.032726*X2) + (0.000464*X3) + (20.1808*X4) + (1.896473*X5) + (-1.889519*X6) + (7.209384*X7) – 18.77022

Y=General Service Electricity Load (GWh) for NLH Customers
X1=Real Personal Income in $2002
X2=Fishery Industry Variable
X3=Domestic Market Share of Electric Heat *Degree Days Heating (Stephenville)
X4=Dummy Variable
X5=Mining Industry Variable
X6=Dummy Variable for 1991 (1991=1, otherwise=0)

1.10.8 NP General Service Non-Electric Heat Forecast

This sector would include all general service businesses in the NP service area that do not use electricity as a primary heating source. This segment of customers is assumed to remain a constant 885 GWh per year throughout the forecast period. This sector is sub-divided into small (300 GWh) and large (585 GWh) classes. It is reasonable to assume that these classifications will not grow in the future because new general service customers primarily install electric heating systems and existing customers that convert to electric heat will be transferred into the NP electric heat group.

1.10.9 NP System Peak Forecast

The winter system peak forecast is prepared through the estimation of one regression equation. This regression equation is used to explain and predict the maximum hourly electricity demand requirements in a given year based on the number of NP domestic non-electric heat customers, the number of NP domestic electric heat customers, the NP weather-adjusted general service load, wind-chill and the marginal price of electricity. The regression equations are derived from NLH system load data, NP customer billing data and Environment Canada weather data. The wind chill variable is based on a twenty hour average temperature and an eight hour average wind. The wind chills are calculated for weather stations at St. John's, Gander and Stephenville and then weighted by the number of customers to calculate an island wind chill figure. The regression has an R-squared of 99.7%, has no auto-correlation effect and all input (explanatory) variables are significant. The regression model estimates that every regular NP customer contributes 1.5 kW and every all-electric NP customer contributes 6.7 kW to the NP system peak. These estimates are reasonable and similar to metered customer load research results of other utilities. The equation takes the following form:

Y= (0.001524*X1) + (0.006727*X2) + (0.157677*X3) + (-18.6309*X4) + (0.234852*X5) + (-8.347*X6) + (-11.25104*X7) + (30.44149*X8)

Y=Annual Maximum Hourly Demand (MW)
X1=Number of NP Non-Electric Heat Customers
X2= Number of NP Electric Heat Customers
X3=Wind-Chill Factor
X4= Marginal Price of Electricity in the Previous Year (t-1)
X5= Weather-Adjusted NP General Service Load (GWh)
X6= Technological Change (<1990=0, 1990=1 increasing by 1 each year, 2010=21)
X7= Non Supper Time (5:00=0, 6:00=0, otherwise=1)
X8=Dummy Variable for a December Peak (December=1, otherwise=0)

1.11 Conclusions and Key Findings

A load forecast predicts future electrical energy (GWh) and demand (MW) requirements, and is a critical factor in developing and evaluating future generation options. MHI has completed a comprehensive analysis of Nalcor's load forecasting methods, data sources, and data analysis techniques. MHI's review has developed the following key findings:

- A detailed analysis of Nalcor's load forecasting practices and methodologies confirms that the load forecast has been performed with due diligence and care using generally accepted practices, except as noted in the next key finding.

- The domestic forecast methodology is acceptable, but consistently under-predicts future energy needs at a rate of 1% per future year. The domestic forecast is entirely prepared using econometric modeling techniques. Although these techniques are acceptable, they are not the best utility forecast practices for this sector. Best utility practices would incorporate end-use modeling techniques into the forecasting process so that electricity growth can be quantified for all major domestic end-uses.

  The general service forecast methodology used by Nalcor is based on a combination of regression modeling and linear extrapolation techniques that have performed extremely well in the past. The general service forecast has produced accuracy levels within 1-2%, and as far as eight to nine years into the future.

  The industrial forecast is prepared on an individual, case-by-case basis, with direct customer contact concerning future operational plans. This methodology is reasonable considering the small industrial customer base on the island, but, in hindsight, the assumption of continued operation of two pulp and paper mills was too optimistic and has adversely affected the industrial forecast accuracy. The assumption of continued operation of the one remaining pulp and paper mill throughout the forecast horizon is optimistic and the assumption of no new industrial load additions after 2015 is pessimistic. The amount of variability due to potential load changes is high and could materially impact the results of the cumulative present worth analysis.

A detailed analysis of load forecasting practices, methodologies and results has led to the following recommendations:

1. Nalcor should develop an end-use forecasting model for the domestic sector. The best utility practice for preparing a domestic energy forecast is to use a combination of regression and end-use modeling techniques. NLH should partner with NP to develop and implement an end-use modeling methodology to predict future domestic energy consumption.

   The additional detail required to prepare an end-use forecasting methodology may improve forecast accuracy, but increased accuracy is not guaranteed because any forecast is dependent on the accuracy of the assumptions on which it is based. The current econometric process produces reasonable results, but it does not possess the explanatory power of an end-use methodology. The recommendation to develop an end-use forecasting methodology for the domestic sector is primarily based on improving the capability to:

   - Quantify load growth by end-use.
   - Quantify energy-efficiency by end-use.
   - Incorporate new end-uses (e.g. electric cars).
   - Improve the design of CDM programs.
   - Improve the defensibility of the load forecasting process.

2. Nalcor should develop a process to integrate the energy and peak forecasting methodologies. NLH staff should partner with NP to develop a coordinated load research program that is designed to develop load shape information by sector and by end-use. Incorporating domestic, general service, industrial and end-use (e.g. space heating) load research information could be used to integrate the energy and peak forecasting processes. Annual energy forecasts could be distributed throughout the 8,760 hours in a year, based on the hourly load shape profiles developed from the load research information. These hourly load forecasts could then be added together to produce an hourly forecast model for the interconnected system.

2 Hydrology Studies

Report by: C. Cadou, P. Eng.

2.1 Introduction

The objective of this analysis was to review the hydrological/hydraulic and energy production components of studies carried out to date for Muskrat Falls and on-island hydroelectric projects (HEPs), including relevance of input source, methodology, accuracy of estimates and/or assumptions, identification of gaps, recommendations on findings and examination of quality assurance mechanisms. Projects evaluated in this Report are:

- Muskrat Falls (Infeed)
- Round Pond (Isolated Island)
- Island Pond (Isolated Island)
- Portland Creek (Isolated Island and Infeed)

The Report covers the review of hydrological/hydraulic and energy production related studies. These studies are far more extensive in the Muskrat Falls case than for the other three HEPs. In the Muskrat Falls case, the topics covered are:

- Hydraulic Modeling of Churchill River
- Construction Flood Estimate
- Probable Maximum Flood (PMF)
- Spillway Design
- Hydraulic Modelling of Structures
- Dam Break Analysis
- Ice Studies
- Energy Estimates

In the case of the island HEPs the review covers:

- Construction Flood Estimate
- Probable Maximum Flood
- Energy Estimates

2.2 Muskrat Falls

2.2.1 Dam Layout

The updated Muskrat Falls dam configuration (Variant 10, Scheme 3b) is comprised of the following structures as outlined in the Muskrat Falls "MF 1050 – Spillway Design Review report"[31].

- South Roller Compacted Concrete (RCC) Dam – approximately 315 m long with a crest elevation of 45.5 m.
- North RCC Overflow Dam – 430 m long with a crest elevation of 39.5 m; capable of passing approximately 8,800 m^3/s at maximum flood level (MFL) of 44 m.
- Four (4) bay gated spillway with submerged radial gates (12.5 m wide by 14.8 m high) with a permanent sill elevation of 5 m; capable of passing 13,305 m^3/s at MFL of 44 m.
- Four (4) unit powerhouse capable of passing 2,667 m^3/s at full load.

2.2.2 Hydraulic Modeling of Churchill River

As part of Muskrat Falls' feasibility studies, Hatch developed a numerical hydraulic model of the Lower Churchill River. The model was originally developed in 2007-2008.[32] However, the corresponding report has not been filed because, since 2007, there have been updates to project layouts and additional bathymetric and hydrometric data which have become available. The current up-to-date model is described in a 2010 update report by Hatch.[33] The model extends from Churchill Falls to the Atlantic Ocean at Grosswater Bay. Bathymetric/topographic cross-sections were obtained from various sources. In total, the numerical model includes 374 cross-sections over a distance of 557 km, which can be considered a detailed model.

Calibration of the model was carried out with the widely used Hydraulic Engineering Centre – River Analysis System (HEC-RAS) water surface profile software package developed by the Hydrologic Engineering Centre of the US Army Corps of Engineers (USACE). The model was calibrated in both steady and unsteady states. Steady state calibration was effected on surveyed water levels and rating curves of gauging stations located on the Churchill River. Except in a few reaches, generally the calibrated surface profile is within a few centimeters of the surveyed profile. The unsteady flow model was calibrated for the 1981 flood observed at Muskrat Falls gauging station and the resulting calibrated flood hydrograph follows closely the observed hydrograph.

A consistency analysis between the steady and unsteady flow models was also carried out. Simulated water levels from the two models for a flow approximately equal to the maximum annual flow were compared. The water levels were within 0.5 m at 95 percent of the cross sections upstream of Goose Bay; the maximum difference between the two models was approximately one meter. It can be concluded that the model is very robust and that both steady and unsteady flow models perform

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[31] Exhibit CE-16 Rev.1 (Public), SNC Lavalin, "Newfoundland and Labrador Hydro Lower Churchill Project Pre-feed Engineering Services - Muskrat Falls Hydroelectric Project MF1050 – Spillway Design Review", December 2007
[32] Exhibit CE-14 (Public), Hatch, "The Lower Churchill Project – GI1190 - Dam Break Study Volume 1", April 2008
[33] Exhibit CE-22 (Public), Hatch, "The Lower Churchill Project MF1330 - Hydraulic Modeling and Studies 2010 Update, Report 1: Hydraulic Studies of the River", October 2010

satisfactorily and can be used for the prediction of velocities and water levels throughout the Lower Churchill River.

This water surface profile modeling is an important step in the study as the model is subsequently used in the following studies of Muskrat Falls:

- Probable Maximum Flood (PMF) study
- Construction Design Flood (CDF) study
- Ice study
- Dam Break study

2.2.3 Probable Maximum Flood and Churchill Falls Flood Handling Procedure

In accordance with the Canadian Dam Safety Association (CDA) Guidelines, the Muskrat Falls dam and reservoir are classified in the high risk category for which the required project design flood is the PMF. The PMF is defined as the flood that would be produced by the most adverse combination of flood producing factors possible from both meteorology and hydrology for the region and season of the year.

Various studies have been completed on the PMF for the Lower Churchill River. The most recent are listed below and were reviewed by MHI.

- Acres 1999 Study[34]
- SNC-AGRA 1999 Study[35]
- Hatch 2007 Study[36]
- Hatch 2009 Study[37]
- Hatch 2010 Study[38]

The earlier studies assumed that the Gull Island development would be built before Muskrat Falls. The Hatch 2010 study revisited the PMF and its routing considering the construction of Muskrat Falls first. The study concluded that:

- at 26,060 m^3/s, the pre-project PMF peak inflow of Muskrat Falls is almost the same as the previous estimate (26,020 m^3/s) and the post-project estimate without Gull Island is 25,060 m^3/s with a maximum water level of 44.78 m.

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[34] Exhibits 50 and 51, Acres International, "Churchill River Complex, PMF Review and Development Study, Volumes 1 and 2, Report for Newfoundland and Labrador Hydro", January 1999
[35] Exhibit 19, SNC-AGRA, "Muskrat Falls Hydroelectric Development – Final Feasibility Study Volume 1 – Engineering Report", January 1999
[36] Exhibit CE-13 (Public), Hatch, "The Lower Churchill Project GI1140 – PMF and Construction Design Flood Study", December 2007
[37] Exhibit CE-54 Rev.1 (Public), Hatch, "The Lower Churchill Project GI1141 - Upper Churchill PMF and Flood Handling Procedures Update", August 2009
[38] Exhibit CE-23 (Public), Hatch, "The Lower Churchill Project MF1330 – Hydraulic Modeling and Studies Update 2010 – Report 2: Muskrat Falls PMF and Construction Design Flood Study", December 2010

- Additional work be undertaken to optimize the spillway design.

Conclusions of PMF Review

As a result of the hydrological review of the PMF, MHI finds that:

- A significant amount of work went into the estimation of the PMF, with a total of seven studies and reviews.
- The Probable Maximum Precipitation (PMP), Probable Maximum Snow Pack (PMSP), and the 1:100-year precipitation and snowpack were derived by professional meteorologists from Environment Canada in accordance with recognized procedures and the recommendations of the Canadian Dam Association (CDA) Guidelines.
- The approach for the routing of the PMF is very detailed with the use of the Streamflow Synthesis and Reservoir Regulation model, widely used in analyses of this type, especially when snowpack and snowmelt are present. A second step to refine the routing with HEC-RAS is bringing a supplementary level of accuracy to the routing process.
- The studies contain all the elements that will facilitate the modification of the flood handling procedure of Churchill Falls once Muskrat Falls is operational.

2.2.4 Construction Design Flood

Considering that the construction of Muskrat Falls will last two years, a construction design flood (CDF) study is a necessary component of the hydrology studies. The CDA guideline recommends adoption of the 1:40-year flood for diversion works and the CDF is made up of two components, the Upper Catchment flood inflow, and the unregulated downstream catchment flood.

Various construction design flood studies were performed for Muskrat Falls. These reports were all reviewed by MHI and are as follows:

- SNC-AGRA 1999 Study[39]
- Hatch 2007 Study[40]
- Hatch 2008 Study[41]
- Hatch 2010 Study[42]

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[39] Exhibit 19, SNC-AGRA, "Muskrat Falls Hydroelectric Development – Final Feasibility Study Volume 1 – Engineering Report", January 1999

[40] Exhibit CE-13 (Public), Hatch, "The Lower Churchill Project GI1140 – PMF and Construction Design Flood Study", December 2007

[41] Exhibit CE-17 (Public), Hatch, "The Lower Churchill Project MF1130 – River Operation during Construction and Impounding", January 2008

[42] Exhibit CE-23 (Public), Hatch, "The Lower Churchill Project MF1330 – Hydraulic modeling and Studies 2010 Update, Report 2: Muskrat Falls PMF and Construction Design Flood Study", December 2010

In the Hatch 2010 study, Hatch updated the CDF study to reflect that Muskrat Falls will be built first. The update was substantial as it included the following changes:

- Updated the statistical flood frequency estimate of the CDF peak flow using the additional available years of record for Muskrat Falls, from Water Survey of Canada hydrometric stations. The observation sample consisted of 30 annual flood peaks during the period over which Churchill Falls was in operation. The resulting 1:20 and 1:40-year peak discharges are respectively 5,910 m^3/s and 6,250 m^3/s, being very close to the values estimated in the 2007 study; and
- Adoption of HEC-RAS as opposed to the Acres Reservoir Simulation Package (ARSP) model, in order to route 1:20 and 1:40-year flood hydrographs through the river channel and diversion facilities.

As in the 2008 study, the flood hydrograph of 1998 was pro-rated to the flood peak of the 1:20-year flood and routing with HRC-RAS resulted in a maximum water level of 22.8 m as opposed to 22.7 m which was reported in the earlier study, thus confirming the results of this prior study. The report presents no similar result for routing of the 1:40-year flood, but the maximum water level is likely very close to the 23.8 m level found in the 2008 study. The Hatch 2010 study concludes that the CDF peak outflow is 5,890 m^3/s and the peak water level is 22.78 m.

Conclusions of Construction Design Flood Review

As a result of the hydrological review of the CDF, MHI finds that:

- As with the PMF analysis, a number of studies have refined the CDF estimate over time. In particular, the analysis carried out in 2007 shows that floods do not occur simultaneously in the Upper and Lower catchments.
- The Lower Catchment flood peak estimation follows a classical flood frequency analysis procedure. With 30 years of observations, the sample is adequate to estimate the 1:40-year flood.
- The CDF analysis has been done in detail using all available information and can be considered final.

2.2.5 Ice studies

The formation of ice below Muskrat Falls will have an impact on how the plant is constructed. Large quantities of frazil and pan ice form in the reach between Gull Island and Muskrat Falls and this ice drifts downstream to the pool below Muskrat Falls where it accumulates forming a very large hanging dam. As a consequence water levels rise to eventually drown out the upper Muskrat Falls. This is an event that has occurred in 1978 and 1979.

This section documents the various ice studies performed for Muskrat Falls and reviewed by MHI. Based on the documents that were reviewed, ice studies were completed in 1999, 2007 and 2010. (Note: The Hatch 2007 study was superseded by the Hatch 2010 study. As such, the 2007 study was not filed by Nalcor).

- SNC-AGRA 1999 Study[43]
- Hatch 2010 Study[44]

The Hatch 2010 update assumed that Muskrat Fall was to be built before Gull Island. The same methodology and approach was adopted as the Hatch 2007 study with calibration of the ICESIM (Ice Simulation) model validated for the 1990-91 and 1991-92 winter seasons which were both colder than usual and with flows lower than average. ICESIM simulated level results were acceptable when compared with actual conditions.

The Hatch 2010 study concluded that results from the 2007 ice study remained valid as follows:

- "It is very unlikely that the water would rise to 20 meters above which flooding becomes a concern."
- "The water level required at the cofferdam to provide appropriate hydraulic conditions for an upstream cover to form was determined through ice modeling to be 25 m."

The Hatch 2010 report recommended:

- "Due to the complexity of the velocity regime expected at the Muskrat Falls cofferdam and the small ice accumulation predicted just upstream of the cofferdam, it is recommended that the 25 m water level determined in this study be optimized during FEED[45] studies.
- The implications of part of the upstream ice cover being lost during the winter should also be considered during future studies. In the event that even a part of this upstream cover breaks up and passes through the spillway, it could lead to rapid water level increases downstream of the plant that may impact any ongoing construction activities in that area."

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[43] Exhibit 19, SNC-AGRA, "Muskrat Falls Hydroelectric Development – Final Feasibility Study Volume 1 – Engineering Report", January 1999
[44] Exhibit CE-25 (Public), Hatch, "Lower Churchill Project MF 1330 – Hydraulic Modeling and Studies 2010 Update, Report 4: Muskrat Falls Ice Studies", March 2011
[45] FEED is defined as Front End Engineering Design

These findings and recommendations should be addressed in the detailed design phase and are relevant as they may impact the cofferdam design, and thus the overall cost of the Muskrat Falls development.

2.2.6 Numerical Modeling of Structures

Numerical modeling of structures is an important tool utilized to assess the performance of the various structures in the river system that comprises the Muskrat Falls development.

This section summarizes findings from the numerical modelling analysis undertaken in the studies noted below and reviewed by MHI.

- SNC-AGRA 1999 Study[46]
- SNC Lavalin 2008 Study[47]

In the SNC-AGRA 1999 study three variants were evaluated: variants 7, 10 and 11 with variant 7 as the recommended variant since it did not require a road to the south side of the proposed complex. Since the SNC-AGRA study, a highway bridge was constructed across the Churchill River 18 km downstream of the site.[48] Following an analysis of comparative costs, schedule and risks, variant 10 proved to be the most attractive development layout.[49] In 2008, SNC-Lavalin was retained by NLH to conduct a numerical modeling study of Muskrat Falls based on variant 10. This study numerically modelled in 3-dimensions the flows for the following hydraulic facilities:

- Diversion channels;
- Powerhouse (approach channel and tailrace channel); and
- Spillway (sluices and overflow crest).

MHI concurs with the findings of the reports reviewed as follows:

- The numeric model was calibrated in natural conditions with water levels of four hydrometric stations in the vicinity of the dam site. Simulated levels were about one meter off from observed levels for a range of discharges indicating a potential issue with the bathymetry at the control section.
- Simulation of diversion facilities indicate the right angle at the upstream end of the retaining wall of the upstream cofferdam generates a zone of low velocity, which reduces the capacity of sluice no. 1. In an improved layout, the right angle is curved with a 75 m radius and the flow through sluice No. 1 improves to the desired level.
- For the power intake facilities, an eddy is shown to occur near units 1 and 2 which could become a vortex and could eventually affect the efficiency of these units. An improved design

[46] Exhibit 19, SNC-AGRA, "Muskrat Falls Hydroelectric Development – Final Feasibility Study Volume 1 – Engineering Report", January 1999
[47] Exhibit CE-18 (Public), SNC Lavalin, "Lower Churchill Project MF1250 – Numerical Modeling of Muskrat Falls Structures", May 2008
[48] Exhibit CE-15 Rev.1 (Public), SNC Lavalin, "Lower Churchill Project MF1010 – Muskrat Falls Hydroelectric Project Review of Variants", March 2008
[49] Exhibit 30, Nalcor, "Technical Note: Lower Churchill Design Progression 1998 to 2011", July 2011

would consist of adding a 39m curved wing wall between the power intake and the spillway together with a longer approach channel.

- For the numerical analysis of the spillway, the PMF adopted in Variant 10, with a peak of 22,100 m^3/s is also considered in the numerical analysis. However, the SNC Lavalin 2008 study recognizes that since the earlier study, the PMF value has been updated and that the updated PMF should be considered in any future update of the study. Simulation results for the PMF conditions show no major problem. However, at maximum normal operating level, a significant vortex forms upstream of sluice no. 1 which may reduce the capacity of this sluice. With a possible increase of the PMF at Muskrat Falls, a fifth sluice could be introduced. It will increase the spill capacity of the system and will give more flexibility during construction. It should be noted that this is also the recommendation of the Hatch 2010 flood review study.

MHI finds that the numerical modeling of the Muskrat Falls structure that was done was appropriate and that the SNC Lavalin 2008 study has identified undesired flow patterns that require adjustments in the final layout.

2.2.7 Spillway Design

Spillway design was studied in the SNC Lavalin 2007 report[50]. This study essentially sizes the spillway gates and estimates the cost of the spillway facility based on the preferred variant 10. This study requires an update to reflect the latest findings on the PMF.

2.2.8 Dam Break Analysis

A dam break analysis of Muskrat Falls was prepared by Hatch in 2010 with Muskrat Falls built first before any Gull Island development.[51] The HEC-RAS model was used to simulate the flood wave downstream of Muskrat Falls as a result of a dam breach. Two scenarios were prepared in accordance with CDA Guidelines (2007):

- dam breach under fair weather conditions, and
- dam breach under PMF conditions using the PMF hydrograph from the Hatch 2010 flood studies update.

The study assumes that the worst case breach scenario would be by sliding or overturning of the North Roller Compacted Concrete (RCC) Overflow Dam, which is 430 m long and has a bottom elevation of 4.0 m. Due to the relatively rapid nature of the failure mechanism, the breach was assumed to be fully formed within one hour of breach initiation.

General findings from the study under fair weather conditions are:

- Outflow immediately downstream of the dam would increase from an initial flow of approximately 1,800 m^3/s (assumed turbine flow) to a peak flow of approximately 70,500 m^3/s.

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[50] Exhibit CE-16 Rev.1 (Public), SNC Lavalin, "Lower Churchill Project Muskrat Falls Hydroelectric Project MF1050 – Spillway Design Review", December 2007

[51] Exhibit CE-24 (Public), Hatch, "Lower Churchill Project MF 1330 – Hydraulic Modeling and Studies 2010 Update, Report 3: Muskrat Falls Dam Break Study", December 2010

- Incremental water level increases would range from approximately 12.8 m downstream of Muskrat Falls to approximately 4.7 m near Mud Lake.
- There would be approximately 1.4 to 1.7 hours of warning time available between the initiation of the breach and the flood wave reaching the populated areas of the downstream reach (Happy Valley - Goose Bay, Mud Lake).

General findings for a breach under PMF conditions are:

- Outflow immediately downstream of the dam would increase from an initial flow of approximately 25,100 m^3/s to a peak flow of approximately 110,900 m^3/s.
- Incremental water level increases would range from approximately 9.7 m downstream of Muskrat Falls to approximately 3.3 m near Mud Lake.
- There would be approximately 0.8 to 1.2 hours of warning time available between the initiation of the breach and the flood wave reaching the populated areas

The report also outlines the consequences of failure in terms of potential loss of life and economic damages. Finally, the report recommends updating the dam break study before preparing the Emergency Preparedness Plan (EPP) to account for any changes in project layout.

MHI finds that the dam break study was carried out following good utility practices.

2.2.9 Energy Estimates

Various energy estimate studies have been completed for the Muskrat Falls development. The most recent of which are listed below. These confidential reports were reviewed by MHI.

- Acres 1998 Study[52]
- Acres 1999 Study[53]
- Hatch 2011 Report on Regulation Study[54]
- Hatch 2011 Report on Firm Energy Production[55]
- Nalcor 2011 Summary Report[56]

The Nalcor 2011 summary report summarizes the various studies related to Muskrat Falls' energy production.

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[52] Exhibit CE-28 Rev.1 (Public), Acres International, "Churchill River Complex: Power and Energy Modeling Study Final Report ", July 1998
[53] Exhibit CE-29 Rev.1 (Public), Acres International, "Churchill River Complex: Optimization Study Volume 1", January 1999
[54] Exhibit CE-26, Hatch, "The Lower Churchill Project MF1330 – Hydraulic Modeling and Studies 2010 Update, Report 6: Muskrat Falls Regulation Study", May 2011
[55] Exhibit CE-21, Hatch, "Estimate the Firm Generation Potential of the Muskrat Falls Development - Final Report for Nalcor Energy", June 2011
[56] Exhibit CE-27 Rev.1 (Public), Nalcor, "Muskrat Falls Hydroelectric Development Summary of Studies on Firm and Average Energy Production", June 2011

The report identifies the provisions of the Water Management Agreement between CF(L) Co which manages Upper Churchill, and Nalcor Energy facilities (Lower Churchill) that are contained in the recent studies.

Finally, the Nalcor report states that so far, the energy studies have considered propeller units whereas in the final design and optimization, Kaplan units will be considered and that efficiencies and energy production estimates will therefore increase. Although not stated explicitly, the implication is that at that stage, the energy study of Muskrat Falls will require an update, as recommended by Hatch.

Conclusions with Respect to Muskrat Falls Energy Studies

MHI concludes from the review of the energy studies that:

- The contribution of Muskrat Falls to the Churchill River Complex in terms of firm and average energy has varied little within the studies despite the fact that different periods have been considered for the flow sequence input. The firm energy available at Muskrat Falls is estimated at 4.47 TWh annually.
- A comprehensive power generation and energy production model of the Churchill River Complex has been prepared which can be used to update the energy estimates once the characteristics of the turbines have been finalized. Energy production of Muskrat Falls will increase especially if in the final design, double regulated Kaplan units are selected with variable pitch blades and wicket gates. These types of units have very flat efficiency curves thereby increasing the energy output.

2.3 Round Pond

The 18 MW Round Pond development is part of the Isolated Island Option with an in-service date of 2020. For Round Pond, the 1988 Feasibility Study report by Shawinigan/Fenco is documented below. This study did not carry out any hydrological analyses as these were readily available from the general Bay d'Espoir regulation study carried out by Acres in 1985. The main report of this earlier study has been filed and reviewed.

- Acres 1985 Study on Bay D'Espoir Flood Analysis[57]

  In 1985, Acres completed a study of Bay D'Espoir hydropower system flood analysis and alternatives study. The main objective, as stated in the study, included the "determination of the extreme flood hydrology for the Bay d'Espoir basin, the analysis of the response of the reservoir system to extreme flood events, and the examination of remedial measures to alleviate unacceptable flooding conditions in the Salmon basin".

- Shawinigan/Fenco 1988 Round Pond Feasibility Study[58]

  The Shawinigan/Fenco study used the results of previous studies, in particular the Acres 1985 Flood Study. In addition, a model of the Bay d'Espoir system was developed as part of the regulation study that was calibrated against the existing Bay d'Espoir system. The model had the capability to add new developments such as Round Pond.

Conclusions on Round Pond Hydrology

MHI concludes from the review of the Round Pond hydrology studies that, as the Shawinigan/Fenco study is over 20 years old, should the Isolated Island Option become the preferred alternative, the Round Pond study needs to be updated to benefit from more recent hydrometeorological and operation data in the Bay d'Espoir System. At that time, a decision should be made to assess whether or not the PMP/PMF study should be updated. In particular the following may need attention:

- The PMP is based on historic maximum snowpack and PMP storm event. Current CDA Guidelines dictate that two cases have to be considered, PMP with 1:100-year snowpack and PMSP with 1:100-year rainfall.
- In the 1985 flood study, the PMP was routed through the watershed by unit hydrograph techniques in order to obtain PMF inflows. The associated methodology treats the rainfall/runoff process as essentially linear whereas the process is non-linear indicating the unit hydrograph approach may need to be replaced by a comprehensive watershed model.
- The Acres 1985 study concludes that some of the existing structures are not competent to pass the PMF. Unless this issue has already been attended to, the impact of routing should be reassessed.

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[57] Exhibit 54, Acres International, "Bay D'Espoir Flood Analysis and Alternatives Study Report for Newfoundland and Labrador Hydro", December 1985

[58] Exhibit 5d, Shawinigan/Fenco Newfoundland Limited, "Newfoundland and Labrador Hydro Feasibility Study - Round Pond Development – Summary Report", September 1988

2.4 Island Pond

The 36 MW Island Pond development is part of the Isolated Island Option with an in-service date of 2015. The proposed development would be located on the North Salmon River within the watershed of the Bay d'Espoir Development, between the existing Meelpaeg Reservoir and the Upper Salmon Development.

MHI has reviewed the following reports as part of its hydrology review:

- Shawmont Newfoundland 1988 Final Feasibility Study[59]
- AGRA-Shawmont 1997 Re-Optimization Study[60]
- SNC-Lavalin 2006 Study[61]

Conclusion on Island Pond Hydrology

MHI concludes that:

- should the Round Pond flood hydrology require an update, then the capability of the diversion canal from Island Pond into Meelpaeg Reservoir may need to be re-assessed to pass an updated PMF.
- the energy figure estimated in the 1997 study, 188 GWh/year is quoted in the report and a single Kaplan unit is recommended with a nominal capacity of 36 MW. Due to the particularly flat characteristics of such units, marginal improvement in power generation can be obtained over Francis units.

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[59] Exhibit 53, Shawmont Newfoundland Limited, "Island Pond Development Final Feasibility Study Volume 1 - Report for Newfoundland and Labrador Hydro", January 1988
[60] Exhibit 52, AGRA ShawMont Ltd, "Island Pond/Granite Canal Re-Optimization and Cost Update Study - Report for Newfoundland and Labrador Hydro", January 1997
[61] Exhibit 5b, SNC Lavalin, "Studies for Island Pond Hydroelectric Project - Final Report for Newfoundland & Labrador Hydro", December 2006

2.5 Portland Creek

The 23 MW Portland Creek development is part of both Options with an in-service date of 2036 for the Infeed Option, and 2018 for the Isolated Island Option.

A feasibility study of Portland Creek hydropower development was completed in 2006 by SNC-Lavalin.[62] The 2006 SNC-Lavalin study contains the latest hydrological analysis.

Conclusions of Portland Creek Hydrology

MHI notes the following conclusions from the hydrology review of Portland Creek:

- Optimization studies indicate that estimated energy production from the development is 141.5 GWh with an installed capacity of 23 MW.
- The report recommends that NLH consider installing a flow gauge in Portland Creek to confirm the yield of this basin as there is anecdotal evidence of higher precipitation, hence greater runoff in Portland Creek catchment than that indicated by the hydrometric station in the Greavett Brook catchment.
- The 2006 SNC Lavalin study is considered adequate to proceed to detailed design with one caveat. The regional flood index method is preferable to the at-site flood frequency analysis. The analysis presented in the SNC-Lavalin report is based on 22 years of flood peaks to yield the 1:1,000-year flood. Typically, the range of credible extrapolation for annual exceedance probability is 1:100 to 1:200 year return period when using at-site stream flow data while it is 1:500 to 1:1,000-year when using regional streamflow data.

[62] Exhibit 5c, SNC Lavalin, “Feasibility Study For Portland Creek Hydroelectric Project”, January 2007

2.6 Conclusions and Key Findings

MHI has reviewed the various hydrology studies provided by Nalcor to determine if they were conducted with due diligence, skill, and care consistent with acceptable utility practices. The hydrological/hydraulic and energy production review of the studies carried out was an examination of Muskrat Falls and the three on-island hydroelectric projects for relevance of input source, methodology, accuracy of estimates and/or assumptions, identification of gaps, recommendations and findings, and examination of quality assurance mechanisms.

The key finding from the hydrology reviews is as follows:

- The Muskrat Falls studies were conducted in accordance with utility best practices, comprehensively, and with no apparent demonstrated weaknesses. Also, the energy and capacity estimates for Muskrat Falls and the three small hydroelectric facilities on the island, which were prepared by various consultants using industry accepted practices, were reviewed and confirmed to be reasonable for DG2.

Other findings from the hydrology reviews are provided for information:

- The Muskrat Falls studies were comprehensive and detailed, with no apparent weaknesses identified. However, some of the analyses need to be finalized as part of the detailed design:
    - Finalization of spillway design in accordance with the latest probable maximum flood results and results of 3-D modeling of structures.
- The 3-D numerical model was calibrated in natural conditions and simulated levels were about one meter from observed levels for a range of discharges indicating some problems likely with the bathymetry at the control section of both waterfalls that may not reflect actual conditions. The consultant who carried out the analysis should specify to what extent this deviation from actual conditions affects the modeling results.
- It may be necessary to increase the proposed diversion capacity of Muskrat Falls, since the flood peak has increased by some 500 m^3/s above the value estimated in the feasibility study.
- A minimum acceptable turbine flow at Churchill Falls during construction should be established in consultation with CF(L)Co.
- The layout needs to be modified in accordance with the findings of the numerical modeling of structures, in particular the shape of the wingwall between the intake and the spillway, sizing and modifications should be tested with the model.
- The dam break analysis needs to be updated with the final layout before implementing the EPP, an activity likely to take place once the project is built or near completion;
- The power and energy generation model needs to be re-run once the relevant parameters have been finalized.

The following conclusions are noted for the small hydroelectric plant hydrological reviews:

- Because the Round Pond study is more than 25 years old, it should be reviewed in light of new data and the possibility of a change in the operation of the Bay d'Espoir System. Since the probable maximum flood part of the study was carried out before current Canadian Dam Association guidelines took effect, possible implications of the guidelines for the probable maximum flood estimate should be investigated.
- For the Island Pond project, should the Round Pond flood hydrology require an update, it may be necessary to reassess the ability of the diversion canal from Island Pond into the Meelpaeg Reservoir to pass an updated probable maximum flood.
- A feasibility study of the Portland Creek development completed in 2006 by SNC-Lavalin is considered adequate to proceed to detailed design. However, the design flood selected as the 1:1000 year flood was estimated from a limited sample of 22 observations. It is possible that a regional flood analysis, such as an Index Flood Method, would provide a more robust estimate.

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3 Reliability Studies

Report by: Dr. Bagen Bagen, P. Eng.
Paul Wilson, P. Eng.

3.1 Introduction

MHI has reviewed material available from Nalcor to determine if reliability studies were conducted with due diligence, skill, and care consistent with acceptable best utility practices. The documentation included:

- Studies and reports on resource planning;
- The Strait of Belle Isle cable crossing;
- The Labrador-Island Link HVdc system overhead line;
- Reliability studies of HVdc schemes; and
- Other related information.

In the design, construction, and operation of electrical power systems one important consideration is whether the system will provide a reliable supply of electricity to meet the needs of the customers. There are many ways to define and characterize reliability and by any metric used, additions to a power system should not degrade the reliability performance of the system. As the Island of Newfoundland is currently isolated electrically, investigations on reliability are one of the primary concerns, particularly when large remote generation sources are proposed to be connected to an electric power system through a long transmission line.

Reliability evaluation methods can be generally classified into two categories: deterministic and probabilistic. Deterministic methods are subjective and based on engineering judgement. Industry practitioner's use these deterministic methods as they are simple, intuitive, and easy to understand. However, elements of power system behaviour are unpredictable and random in nature. Also, power systems are increasing in complexity. Thus, probabilistic reliability methods applied to modern power systems are an improved and more accurate method for reliability assessment. Deterministic techniques are being augmented by probabilistic methods particularly for significant projects[63] by leading North American electric power entities; Manitoba Hydro, BC Hydro, Hydro Quebec, Hydro One in Ontario and the Northeast Power Coordinating Council, Inc. (NPCC) have all adopted probabilistic methods to establish system reliability metrics. Industry working groups, who provide guidance to reliability practitioners, are now recommending that these methods be adopted as industry wide standards.

The Island of Newfoundland is fully isolated from the North American grid as depicted in Exhibit 102.[64] The predominant load centre is located on the Avalon Peninsula with a narrow corridor of land connecting the rest of the Island. On this corridor are two parallel transmission lines TL203 and TL237.

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[63] R. Billinton, J. Satish, "Adequacy Evaluation in Generation, Transmission, and Distribution Systems of an Electric Power System", 1993, IEEE 0-7803-1319-4/93

[64] Exhibit 102, "Provincial Generation and Transmission Grid," January 2011

A third transmission line is planned for this corridor along with the proposed HVdc transmission line. Generation largely resides west of this thin corridor at Bay D'Espoir and other plants north and west. A large transfer of power flows along the transmission corridor defined by transmission lines TL202/TL206 and TL203/TL237. The load east of Bay D'Espoir is approximately 67% of the island demand of 1052 MW in 2012[65]. The configuration of the transmission system, along with the location and arrangement of available generation, as well as the location of the loads must be considered in a reliability study.

Nalcor has defined their generation planning criteria for generation in terms of Loss of Load Hours (LOLH). Generation must be installed and have sufficient capacity and energy as defined to meet LOLH[66]:

> *"Capacity: The Island Interconnected System should have sufficient generating capacity to satisfy a Loss of Load Hours (LOLH) expectation target of not more than 2.8 hours per year.*
>
> *Energy: The Island Interconnected system should have sufficient generating capability to supply all of its firm energy requirements with firm system capability."*

The 2.8 hours per year is an important metric as it is used as one of the inputs to determine both the timing and size of new generation in the Strategist Program. The reserve margin is determined considering both the Forced Outage Rates (FOR) of generating units and maintenance requirements. For the isolated power systems, higher reserve margins are normal. Periodically, review of system adequacy must be assessed to determine the financial impact of carrying this additional reserve margin.

Reliability considerations change when interconnections are present in the power system. Interconnections may bring reliability improvements as generation resources can be shared with neighbours. Nalcor has defined the first interconnection to the Island from Labrador with the Labrador-Island Link HVdc System starting at Muskrat Falls and terminating at Soldier's Pond on the Avalon Peninsula. A second link discussed in the Technical Note is the Emera 500 MW HVdc link from Bottom Brook to Lingan, Nova Scotia. The Emera curtailable capacity to Nova Scotia Power noted in that document is 162.2 MW with 300 MW import capability onto the Island of Newfoundland.

Reliability assessment is most often used to determine the adequacy of generation and/or transmission to meet the load. Current industry trends in practical generating systems, extend adequacy analysis from the conventional first level assessment to include major transmission limitations.

When reliability assessments are to be performed, data is derived from a number of sources based on the system components in order to fully characterize reliability. Existing reliability metrics in use by Nalcor are as follows:

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[65] Exhibit 106, Nalcor, "Technical Note: Labrador – Island HVdc Link and Interconnected System Reliability", October 2011
[66] Nalcor's Submission to the Board of Commissioners of Public Utilities with respect to the Reference from the Lieutenant-Governor in Council on the Muskrat Falls Project, November 2011

- For hydraulic generation units, the Derating Adjusted Forced Outage Rate (DAFOR) is used as the Forced Outage Rate input into Strategist, or the Canadian Electricity Association – Equipment Reliability Information System (CEA ERIS) report.
- For thermal units, Nalcor is using their experience from their existing units.
- For CCCTs, Nalcor has specified a forced outage rate (FOR) of 5%.
- For the Labrador-Island Link HVdc System, Nalcor has specified a FOR of 0.89% on a per pole basis. This value is listed in Exhibit 26; however, it is not evident how this value was obtained from this Exhibit.

A summary of documents relevant to the review and analysis of reliability are described in this report, then followed by HVdc pole and bipole outage statistics, and then by a discussion on probability reliability assessment as a best practice.

3.2 Exhibit Documents Reviewed

A brief summary of some of the major documents reviewed is provided as follows:

1. Exhibit 12, "Forced Outage Rates Summary Sheet" outlines the input values used for the Strategist generation resource planning tool.
2. Exhibit 26, "Forced Outage Rates 2006 Update" is a document that describes the values, and the sources used in Exhibit 12 and is an input into the development of more advanced reliability models.
3. Exhibit 33, "Summary of Ocean Current Statistics": This report reviews and summarizes the available ocean current data of the Strait of Belle Isle. The mean and maximum expected current speeds along the potential HVdc cable system corridor route are estimated based on historical data records. The mean and maximum expected current speed estimates are provided for each season and three different depth levels. These estimates may be used as input for the development of a reliability model of the HVdc marine crossing cable system.
4. Exhibit 34, "Review of Fishing Equipment": The studies described in this report identify some of the specific fishing gear and related equipment which may interact with the Strait of Belle Isle HVdc cable system. The study also estimates the expected durations and number of passes over the possible cable crossing areas for existing and potential fishing activities. This information could be used to estimate the Strait of Belle Isle HVdc cable system risks exposure to various fishing operations. The information can also be used in the development of a reliability model of the HVdc marine crossing cable system.
5. Exhibit 35, "Nalcor Strait of Belle Isle Iceberg Cable Risk": This report presents the application of a drift model based on a Monte Carlo Simulation to assess iceberg risks to cables laid on the seabed in the Strait of Belle Isle. The simulation results are compared with the iceberg scour data derived from surveys for model evaluation and risk analysis. The report also estimates iceberg risks to cables laid on the seabed for particular routes and configurations. This information can be used to estimate the Strait of Belle Isle HVdc cable system risks exposed to

icebergs. The information can also be used as input into the development of a reliability model for the HVdc marine crossing cable system.

6. Exhibits CE-40, CE-41, CE-42, CE-43, CE-44: These reports present the results of a series of feasibility studies on the seabed installation of HVdc power cables across the Strait of Belle Isle. These studies include technical feasibility of dredging and backfilling, shore approach trenches for a cable crossing including horizontal directional drilling (HDD), a rock berm method for cable protection and the Strait of Belle Isle seabed crossing conceptual design. These reports provide useful information in understanding the risks associated with the HVdc cable system. The information may be used in the development of a reliability model of the HVdc marine crossing cable system.

7. Exhibit 48, "Newfoundland and Labrador HVdc Link Reliability Studies": This report summarizes the results of probabilistic reliability studies on the proposed ±400 kV Labrador-Newfoundland HVdc project, from 1981. Annual failure rates and repair times are estimated for the overhead portion (ac/dc lines), cable crossing of Strait of Belle Isle and HVdc terminal equipment, mainly based on Cigré statistics. An overall system reliability model is developed from the subsystem or component reliability models. The HVdc system reliability is evaluated for both dc and ac links from Gull Island to Churchill Falls in terms of probability, frequency and duration of various levels of transfer capability using an analytical approach.

8. Exhibit 57, "Reliability of the Strait of Belle Isle HVdc Cable System": The studies described in this report are similar to those provided in Exhibit 48. They include the review of operating history of undersea cable systems similar to those alternatives proposed for the Strait of Belle Isle at that time, the estimate of iceberg scour risk, the assessment of the reliability of the proposed cable alternatives, incorporation of the cable system reliability models into the overall system reliability model and the development of an equivalent reliability model for the overall HVdc system. The equivalent reliability model of overall HVdc system is expressed in terms of a single generating unit capacity and associated forced outage rate.

9. Exhibit 106, "Labrador-Island HVdc Link and Island Interconnected System Reliability": This report reviews various system reliability components including planning, operation, design, and examines the reliability impacts of the Labrador-Island Link HVdc system, and compares the reliability of the two options. The reliability effects of the Labrador-Island Link HVdc system are assessed considering single pole or bipole outages and the probabilities of these events are factored into reliability index calculations. The study methodology described in this report is deterministic in nature for a limited set of assumptions and conditions.

3.3 LOLH and LOLE Defined

The two most commonly used indices in probabilistic reliability studies are the Loss of Load Expectation (LOLE) and the Expected Unserved Energy (EUE)[67 68]. The LOLE measures the likelihood of the system not being able to carry the desired load. Different reliability indices can be obtained by using different load models:

- LOLE index (days/year) is evaluated using daily peak load values, for example 0.1 days/year or a one day in ten year event.
- LOLH index (hours/year) is obtained using hourly load values, for example 2.8 hr/yr. This metric may also sometimes be referred to as LOLE which only adds to the confusion.

It is not valid to obtain the LOLE by simply multiplying LOLH by 24, because the hourly load profile is normally quite different from that of the daily peak load. The ratio of the LOLE in hours/year (LOLH) over the LOLE in days/year is always less than the value of 24 in an actual power system[69].

Generally each utility sets its own level of acceptable risk but a LOLE of 0.1 days/year on an annual base is unofficially used across North America particularly for resource adequacy planning [70 71 72]. Nalcor has determined that "The Regional Reliability Organization criterion of one day in 10 years is more stringent than NLH's LOLH of 2.8 hours per year which equates to about one day in every five years"[73].

The LOLE index is not often easily interpreted or understood, and it is sometimes translated into another risk index – load carrying capability. The load carrying capability is the maximum system peak load that can be carried by a system without violating the acceptable LOLE criterion.

The EUE is the amount of energy not delivered to the customer as a result of the loss of load due to random outages. This index has become the preferred index as it represents something physical, such as energy delivered to customers. This index can be converted to a monetary value, as done with Manitoba Hydro's Bipole III studies, and therefore provides the means to assess cost implications of system risks. Nalcor makes a statement on page 32 of Exhibit 106, that it is difficult to calculate the cost of increasing quality and requires the utility to have a sound understanding of the value of outage to each of its customer classes[74]. However, sophisticated study tools available today allow EUE to be easily calculated as part of reliability adequacy studies.

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67 R. Billinton and R. Allan, Reliability evaluation of power systems, 2nd Edition, Plenum Press, New York, 1996
68 Wenyuan Li, "Risk Assessment of Power Systems: Models, Method, and Applications", IEEE Press, Wiley-Interscience, 2005
69 R. Billinton and D. Huang, "Basic concepts in generating capacity adequacy evaluation", in Proc. Int. Conf. Probabilistic Methods Applied to Power Systems PMAPS 2006, 2006, pp. 1-6
70 Resource and Transmission Adequacy Task Force of the NERC Planning Committee, "NERC Resource and Transmission Adequacy Recommendation", June 2004
71 RFC Standard BAL-502-RFC-02: Planning Resource Adequacy Analysis, Assessment and Documentation, December 2008:
72 Midwest ISO Business Practices Manual: Resource Adequacy, June 2009:
73 Nalcor's Submission to the Board of Commissioners of Public Utilities with respect to the Reference from the Lieutenant-Governor in Council on the Muskrat Falls Project
74 Exhibit 106, Nalcor, "Technical Note: Labrador – Island HVdc Link and Interconnected System Reliability", October 2011

3.4 HVdc System Reliability Review

Historically, HVdc transmission system performance suffered from poor reliability with high Forced Energy Unavailability (FEU) and high Scheduled Energy Unavailability (SEU) indices when compared to ac transmission lines of the same power rating. The following two tables only provide two years of recent data for systems that report. For a complete discussion, see Cigré B4-209, "A survey of the Reliability of HVdc Systems throughout the World During 2007-2008", 2010.[75] The metrics on these tables are:

f_p = number of pole outages per terminal per year

f_b = number of bipole outages per bipole per terminal per year

d_p = average duration of pole outages in hours

d_b = average duration of bipole outages in hours.

Table 18 shows the average frequency and duration of converter, pole and bipole outages for two-terminal and multi-terminal systems. The frequency of outages is given on a per terminal basis and does not include transmission lines or cables.

Table 18: Forced Outage Statistics, Two Terminal Systems - One Converter per Pole

System	2007				2008				Average to 2008				
	Pole		Bipole		Pole		Bipole		Years	Pole		Bipole	
	fp	dp	fb	db	fp	dp	fb	db		fp	dp	fb	db
Skagerrak 1 & 2	1.25	3.1	0.00	0.0	2.00	3.8	0.50	1.0	20	1.54	17.1	**0.13**	**1.03**
Skagerrak 3 (1)	1.00	1503.2	-	-	0.50	4360.4	-	-	15	1.53	**484.2**	-	-
Square Butte	1.00	4.1	1.50	0.3	5.25	0.8	0.00	0.0	18	2.85	6.2	**0.42**	**2.27**
CU	0.50	23.8	0.00	0.0	1.25	58.5	0.00	0.0	20	1.71	4.6	0.28	1.66
Gotland 2 & 3	0.25	0.8	0.00	0.0	0.50	46.6	0.00	0.0	20	**0.38**	35.8	0.20	1.49
Fennoskan (1)	2.00	14.2	-	-	1.50	46.4	-	-	19	2.26	10.1	-	-
SACOI (3)	3.33	1.7	-	-	1.67	2.5	-	-	16	**4.90**	**2.6**	-	-
New Zealand Pole 2 (3)	2.50	4.3	-	-	0.50	0.7	-	-	17	1.65	2.7	-	-
~~Kontek (1)~~	~~0.50~~	~~2.7~~	-	-	~~1.00~~	~~32.0~~	-	-	~~7~~	~~0.86~~	~~15.7~~	-	-
~~SwePol (1)~~	~~0.50~~	~~2.4~~	-	-	~~2.00~~	~~1.7~~	-	-	~~8~~	~~3.56~~	~~21.0~~	-	-
~~Kii Channel~~	~~0.00~~	~~0.0~~	~~0.0~~	~~0.0~~	~~0.00~~	~~0.0~~	~~0.00~~	~~0.0~~	~~8~~	~~0.16~~	~~99.6~~	~~0.00~~	~~0.00~~
~~Grita (1)~~	~~4.00~~	~~42.2~~	-	-	~~4.5~~	~~9.3~~	-	-	~~5~~	~~2.70~~	~~17.1~~	-	-

In Nalcor's technical note on reliability, Exhibit 106 [76], HVdc pole outages are discussed with the data selected from the Cigré B4-209 survey. Nalcor has also stated that only systems with 15 years or more of service are considered by them.[77] Values not meeting this criterion have been stroked out from Table 18. The range of forced energy unavailability (FEU) is 0.38 to 4.9 pole failures per terminal per year, with durations of 2.6 to 484.2 hours.

[75] CIGRE B4 – 209, "A survey of the Reliability of HVdc Systems throughout the World During 2007-2008", 2010
[76] Exhibit 106, Nalcor, "Technical Note: Labrador – Island HVdc Link and Interconnected System Reliability", October 2011
[77] Response to RFI PUB-Nalcor-165

Nalcor describes in detail how they plan to manage the balance of demand, with alternative supply and HVdc pole overload, for a single pole outage and no Maritime Link. In this document a statement is made that

> *"if the Labrador – Island Link is providing maximum deliveries (i.e. 807.9 MW), there must be a minimum of 180.7 MW of spinning reserve carried by the Island Interconnected System generation to cover the capacity deficiency for loss of a pole and/or loss of the largest unit on the Island System. The additional inertia provided by the proposed high inertia synchronous condensers will assist in ensuring frequency on the system is maintained above under frequency load shedding levels so that the governors on the hydroelectric units carrying the spinning reserve can respond to loss of the pole and increase output to make up the 180.7 MW deficiency."*

When load is shed by the special protection system due to a loss of supply, the frequency will decay and then recover to a control point that would be less than nominal frequency due to the bandwidth setting in the frequency error control loop. Thus, in practice the entire 180.7 MW generation deficiency would not be recovered by governor action alone from spinning reserve. There must be an operator dispatching new generation to make up the short fall for frequency to fully recover. If the shortfall exceeds capabilities of the pole with the 150% continuous overload rating, then new generation must be dispatched within the ten minute window provided in the HVdc system rating specification. One must also consider the reliability of the starting sequence for CTs as the ten minute window is a short time for an operator to take corrective action. CTs typically have a start time of 30 minutes, however, they may be configured for quicker starting times. The CT start sequence probability of success should be factored into the reliability model.

Bipole outages are more severe than single pole outages. In Exhibit 106, Page 16, Nalcor has restated the frequency and durations of bipole outages.[78] From this, a reliability engineer would anticipate that the Labrador-Island Link HVdc system would see a bipole outage every 0.13 years (one outage every 7.7 years) to 0.42 bipole outages per year (one every 2.3 years) with the maximum duration of 2.27 hours. In this situation, the bipole will be returned to service in under three hours for converter station forced outages. Unfortunately, this does not provide a complete picture of the performance of the Labrador-Island Link HVdc system together with the 1100 km overhead transmission line, and the 30 km Strait of Belle Isle marine crossing. These must also be factored into the reliability equation. Table 2 of Exhibit 106 is incomplete and does not show the reliability performance of HVdc systems with marine crossings. Note: one may argue that the cable configurations outlined are not comparable to the Strait of Belle Isle marine crossing with its spare cable. This system would not see the same severity of outages.

Table 19 provides complete details from the Cigré B4-2009 survey document and outlines all values for the Number of Forced Outages and Equivalent Durations of Overhead and Submarine Cable lines. Some of the submarine cable outage durations are long due to lack of spare cable, and the amount of time required to locate, plan, and affect cable repairs. Note: this table includes back to back converters which will not have transmission line outages.

[78] Exhibit 106, Nalcor, "Technical Note: Labrador – Island HVdc Link and Island Interconnected System Reliability", October 2011

Table 19: Number of Forced Outages and Durations of Overhead and Submarine Cable lines

Project	2007		2008	
	Number	Duration (hr)	Number	Duration (hr)
Skagerrak 1 & 2	0	0.0	0	0.0
Skagerrak 3	1	2.3	0	0.0
Vancouver Island Pole 1	0	0.0	0	0.0
Square Butte	2	194.6	1	64.5
Shin-Shinano 1	0	0.0	0	0.0
Shin-Shinano 2	0	0.0	0	0.0
Nelson River BP1	0	0.2	2	2.1
Nelson River BP2	1	0.0	4	0.6
Hokkaido-Honshu	0	0.1	0	0.0
CU	1	0.0	0	0.0
Gotland 2 & 3	0	0.0	0	0.0
Itaipu BP1	0	0.0	0	0.0
Itaipu BP2	1	0.1	0	0.0
Highgate	0	0.0	0	0.0
Virginia Smith	0	0.0	0	0.0
McNeil	0	0.0	0	0.0
Fennoskan (cable failure)	1	1005.5	0	0.0
SACOI (cable failure)	3	530.3	4	581.0
New Zealand Pole 2	1	0.3	5	9.3
Sakuma	0	0.0	0	0.0
Kontek (cable failure)	1	1624.5	0	0.0
Minami-Fukumitsu	0	0.0	0	0.0
SwePol	0	0.0	0	0.0
Kii Channel	0	0.0	0	0.0
Grita (cable failure)	1	610.5	1	2.5
Rivera	0	0.0	0	0.0
Higashi-Shimizu	0	0.0	0	0.0
Basslink	0	0.0	0	0.0

As this is only a two year snap shot of survey data, the data is not representative of the overhead and submarine cable reliability and is only useful to demonstrate that failures do occur, and in some cases, for extended periods of time. The amount of plant installed to cover off risk factors and contingencies (for example, overload rated submarine cables with a spare cable, converter station pole overload, redundant auxiliary supplies, backup generation, etc.) mitigate these risks through appropriate design.

Modern HVdc converter stations have proven very reliable. New HVdc converter stations are normally specified in tender documents with a Forced Energy Unavailability of 0.5% with a guaranteed rate of 1% with penalties for poor performance.

Probabilistic reliability studies, which are covered in section 3.8 are necessary to evaluate the expected costs of the risks and assess the performance of these HVdc converter stations, the HVdc transmission line, and the marine cable crossings together as the Labrador-Island Link HVdc system.

3.5 Equivalent Short Circuit Ratio

Nalcor's Exhibit 106 justifies its 50-year return period for transmission line design based on the inability of the Labrador-Island Link HVdc system to deliver power at Solder's Pond if the 230 kV transmission system was not intact. When taken to the extreme, if there is no available 230 kV transmission lines at Soldier's Pond, this would result in no power delivery, and if the entire 230 kV transmission system emanating from Soldiers Pond were compromised, this would be true.

In order for the Labrador-Island Link HVdc system to deliver power to the Soldiers Pond Converter Station utilizing Line Commutated Converter technology, a supply of voltage and reactive power is required at the 230 kV ac bus. The reactive power would be available from the three 300 MVAr synchronous condensers located at Soldiers Pond, and starting voltage and power would have to come from a nearby generating station. The amount of power delivered by the Labrador-Island Link HVdc system is variable on a dispatcher controlled power order. With modern HVdc conventional converter designs, it is possible to deliver low amounts of power (less than 10% on converter ratings).

Nalcor states that "the 230 kV transmission system must be reasonably intact to provide the necessary equivalent short circuit ratio (ESCR …)" for Soldiers Pond to function properly[79]. ESCR is a simplistic but useful index in the analysis of dc systems. ESCR is defined by the following formula:

$$ESCR = \frac{SCMVa - Qf}{Pdc}$$

Where:

ESCR is the equivalent short circuit ratio

SCMVa is the short circuit rating of the ac system

Qf is the reactive power rating of the filters and capacitors on the ac bus

Pdc is the power transmitted by the HVdc system.

In words, the equivalent short circuit ratio is the short circuit level of the ac bus (used to define the strength of the ac system which is dependent on the number of 230 kV transmission line connections), less the reactive power rating of the filters and capacitors, all divided by the dc power. At full rating, an ESCR less than 2.0 (as is the case at Soldiers Pond) is considered a weak system which presents special control and operational issues for dc systems.

However, ESCR tends to increase with less dc power delivered, i.e. with a reduction in Pdc with no change in short circuit levels. One can interpret that ESCR is not a barrier to deliver dc power in reduced amounts provided some of the 230 kV transmission system is intact.

[79] Exhibit 106, Nalcor, "Technical Note: Labrador – Island HVdc Link and Island Interconnected System Reliability", October 2011

3.6 Component and Sub-system Reliability Modeling

The components and/or subsystems that should be modeled in a probabilistic reliability assessment usually consist of generating units and major transmission facilities. The average performance data from the 2004 Canadian Electricity Association Annual Report on Generation Equipment Status used to develop Forced Outage Rates (FOR) for various types of generating units is well founded and reasonable. Although no detailed information is available for review on the Labrador-Island Link HVdc system converter station reliability, reliability data from manufacturers or from data collected on similar systems[80] can be used to model converter station components for reliability studies. Some of the procedures and methodologies described in earlier reports prepared by Power Technologies Inc. (PTI) (Exhibit 48 "Newfoundland and Labrador HVdc Link Reliability Studies" and Exhibit 57 "Reliability of the Strait of Belle Isle HVdc Cable System") are still applicable and may be used to develop reliability models for the Labrador-Island Link HVdc system with appropriate updates and modifications. The model and study development may involve:

1. A review of technical specifications of the proposed system and operating history of similar installations around the world;
2. An estimate of specific risks, for example: icebergs, fishing dredges and ocean currents for the Strait of Belle Isle cable crossing and rime ice and salt contamination for the overhead HVdc line;
3. Develop reliability component models of the proposed cable, overhead line and converter stations; and
4. Amalgamate the various component reliability models to form the overall Labrador-Island Link HVdc system reliability model.
5. Link the Labrador-Island Link HVdc system model into the island power system reliability model.
6. Perform the reliability study.

A 0.89% forced outage rate is specified by Nalcor for the Labrador-Island HVdc Link.[81] Currently most manufacturers are able to provide HVdc systems with a reasonably high degree of reliability. The information documenting the derivation of the Labrador-Island Link HVdc system FOR of 0.89% on a per pole basis was not available for MHI's review. However, MHI has compared the Labrador-Island Link HVdc system pole FOR rate of 0.89% with published information and that of Manitoba Hydro's HVdc system (including the HVdc transmission line) and finds it acceptable. However, this FOR should be replaced by a more advanced and comprehensive reliability model incorporating all components of the Labrador-Island Link HVdc system.

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[80] M. G. Bennett, N. S. Dhaliwal and A. Leirbukt, "A survey of the Reliability of HVdc Systems Throughout the World 2007-2008", 43rd CIGRE Session, Aug 22-Aug 27, 2010, Paris, France
[81] Exhibit 12, Nalcor, "Forced Outage Rates Summary Sheet", June 2006

3.7 Deterministic Reliability Assessment

Deterministic reliability assessment is predominantly used in Nalcor's Exhibit 106 to assess impacts of the loss of generation: either the largest unit on the Island, the Labrador-Island Link HVdc system in one or two pole blocks, or the Emera link. This type of assessment provides snap shots in time of system performance based on a set of assumptions and fixed load pattern.

Deterministic approaches are rather simplistic and do not provide an exhaustive examination for system resource adequacy based on more sophisticated models and techniques.

3.8 Probabilistic Reliability Studies

One of the important factors that should be considered in evaluating power system enhancement alternatives is the reliability benefit associated with each option. Risk based or probabilistic reliability evaluation is widely accepted in the power industry to determine the ability of a component, a subsystem or a system to perform its intended function. The numerous uncertainties facing the industry drive a need to use probabilistic evaluation methodologies in power system reliability. The electric power industry particularly in North America is, therefore, adopting the use of the probabilistic reliability assessment approach.[82] [83] [84]

In probabilistic methods, a full model of the generators, transmission lines, HVdc system, maintenance schedules, unit dependencies, and other significant risk factors are considered along with variations in the system load. A commonly used method to process reliability calculations is to use Monte Carlo simulations. These tools randomly change various element states (fail the element) across the model.

3.9 Industry Adoption of Probabilistic Methods

In 2004, the Planning Committee (PC) of the North American Electric Reliability Council (NERC) recommended that each NERC region or sub-region should establish a resource adequacy criterion (or criteria) based on probabilistic metrics and perform probabilistic resource adequacy assessments periodically in order to demonstrate that the regional or sub-regional resource adequacy requirements are being satisfied. In 2008, the Reliability First Corporation (RFC) developed and approved a standard in order to establish common criteria in resource adequacy evaluation for the RFC region. The standard puts in force the use of a probabilistic approach in resource adequacy evaluation.[85]

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[82] Resource and Transmission Adequacy Task Force of the NERC Planning Committee, "NERC Resource and Transmission Adequacy Recommendation", June 2004
[83] RFC Standard BAL-502-RFC-02: Planning Resource Adequacy Analysis, Assessment and Documentation, December 2008f
[84] NERC's Generation and Transmission Reliability Planning Models Task Force, "Generation and Transmission Reliability Planning Models Task Force Final Report on Methodology and Metrics", September 2011
[85] Resource and Transmission Adequacy Task Force of the NERC Planning Committee, "NERC Resource and Transmission Adequacy Recommendation", June 2004

In 2010, NERC's Generation and Transmission Reliability Planning Models Task Force (GTRPMTF) recommended a common generation and transmission reliability modeling methodology and a common set of probabilistic reliability indices for the purpose of resource adequacy assessment across NERC. The GTRPMTF recommendations particularly emphasize the inclusion of major transmission restrictions in resource adequacy evaluation[86].

Risk based reliability evaluation has gained renewed importance in the industry particularly since the 2003 North American blackout. The predominant application of probabilistic techniques is still in the domain of adequacy including consideration regarding transmission restrictions.[87,88,89,90] The terms "adequacy" and "reliability" are, therefore, interchangeable in most cases and are identical in the following discussions in this report. Generally probabilistic reliability evaluation in power systems includes, but is not limited to, determination of component and sub-system outage models, evaluation of overall system adequacy including alternative comparisons and assessment of economics associated with various system reliability levels, including value based reliability analysis[91]. Within this perspective, various available studies, reports and related information regarding the reliability aspect of the two supply options have been reviewed.

The following are some of the examples where the industry performs probabilistic reliability studies:

1. Northeast Power Coordinating Council, Inc. (NPCC) performs annual LOLE studies for the region considering transmission restrictions.
2. In other NERC regions, individual utility or Independent System Operator (ISO) planning authorities, similar studies are performed annually. For example, the MISO utilities in RFC, MAPP and Manitoba Hydro in Midwest Reliability Organization (MRO), BC Hydro, Idaho Power, and California ISO in Western Electricity Coordinating Council (WECC) all perform these studies.
3. Particular project examples include studies done by BC Hydro for the Vancouver Island Transmission Reinforcement Project, assessment of Manitoba Hydro's HVdc Bipole III alternatives, and Hydro One's studies on transmission planning and asset management in Ontario.
4. There are several consulting companies performing probabilistic studies in North America for example GE (using MARS tool), ABB (using GRIDVIEW tool), Associate Power Analyst (using NARP tool) and Astrape Consulting (using SERVM tool).

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[86] RFC Standard BAL-502-RFC-02: Planning Resource Adequacy Analysis, Assessment and Documentation, December 2008
[87] Midwest ISO Loss of Load Expectation (LOLE) Studies
[88] Northeast Power Coordinating Council Interregional Long Range Adequacy Overview, November 2010
[89] PJM CETO Report, October 2009
[90] Glenn Haringa, "California Independent System Operator for Planning Reserve Margin (PRM) Study-2010-2020", April 2010
[91] R. Billinton and R. N. Allan, Reliability Evaluation of Engineering Systems: Concepts and Techniques, Plenum Press, New York, 1992

3.10 Reliability Comparison of the Two Options

The proposed Labrador-Island Link HVdc system is a crucial part of the Infeed Option. The impacts of the HVdc link on the overall system reliability performance should, therefore, be quantitatively evaluated in order to provide valuable inputs to the decision making process. The most performed studies in the power industry is resource adequacy assessment considering transmission restrictions.[92,93,94] The primary concern in resource adequacy studies is to assess the capability of system resources to serve the total system demand.

The impact of the proposed Labrador-Island Link HVdc system can be quantified in terms of these commonly used reliability indices of load carrying capability, LOLE/LOLH or EUE. However, there are no such probabilistic study results available for review. The studies described in Exhibit 106 do not use the probabilistic methods nor fully address this concern.

Comparisons of the two options in terms of reliability should be one of the important inputs to the decision making process. The relative reliability level of these options can be determined based on a series of comparative analyses with a do nothing option, Isolated Island Option, and the Infeed Option. Reliability assessment for the Infeed Option could consider the generation, load, firm export/import sales, demand side management programs and interruptible load, particularly as related to the proposed Labrador-Island Link HVdc system associated with Muskrat Falls' generation. The Isolated Island Option evaluation may include all of the above with the exception of the transmission. A comparison of system reliability in terms of LOLH for the two alternatives produced from the Strategist Program shows that the reliability of the Infeed Option is slightly better than that of the Isolated Island Option. [95] A full Labrador-Island Link HVdc system reliability modelling is, however, not considered in this comparison as the HVdc system was only modelled as an unrestricted thermal source with an FOR of 0.89%.

The resource adequacy assessment could also include a comparison of system reliability in terms of EUE and associated risk costs. [96,97,98] The risk costs can be evaluated using either the method based on risk cost function or on the method based on gross domestic product (GDP)[99,100]. In the first method, a risk cost function is obtained from customer surveys and the relevant statistics analysis. Usually the risk cost is regional and system specific. In the second method the risk cost is estimated based on GDP

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[92] Wenyuan Li, "Probabilistic Reliability Assessment of Central Vancouver Island Transmission Project: Expected Energy Not Supplied Assessment" July 2007

[93] Wenyuan Li, "Probabilistic Reliability Assessment of Central Vancouver Island Transmission Project Expected Energy Not Served (EENS) Study for Vancouver Island Transmission Reinforcement Project Part I: Reliability Improvements due to VITR" December 2005

[94] Wenyuan Li, "Expected Energy Not Served (EENS) Study for Vancouver Island Transmission Reinforcement Project Part II: Comparison between VITR and Sea Breeze HVdc Light Options" December 2005

[95] Exhibit 12, Nalcor, "Forced Outage Rates Summary Sheet", June 2006

[96] R. Billinton and R. N. Allan, Reliability Evaluation of Engineering Systems: Concepts and Techniques, Plenum Press, New York, 1992

[97] Wenyuan Li, "Probabilistic Reliability Assessment of Central Vancouver Island Transmission Project: Expected Energy Not Supplied Assessment" July 2007

[98] Wenyuan Li, "Probabilistic Reliability Assessment of Central Vancouver Island Transmission Project Expected Energy Not Served (EENS) Study for Vancouver Island Transmission Reinforcement Project Part I: Reliability Improvements due to VITR" December 2005

[99] NERC's Generation and Transmission Reliability Planning Models Task Force, "Generation and Transmission Reliability Planning Models Task Force Final Report on Methodology and Metrics", September 2011

[100] R. Billinton and R. Allan, Reliability evaluation of power systems, 2nd Edition, Plenum Press, New York, 1996.

for region and total annual electric energy consumption in a particular period. It was confirmed by Nalcor Energy that there were no studies conducted on system EUE and associated risk costs therefore risk costs were not factored in the economic analyses.

3.11 Conclusions and Key Findings

Available documentation for reliability assessment performed by Nalcor has been reviewed by MHI. The adequacy criteria of 2.8 hours/year of loss of load expectation for resource planning, which considers both generation resource availability and economics, appears reasonable when compared to practices of other operating utilities[101].

The HVdc system together with the overhead transmission line and submarine cable will have pole and bipole outages, and in some cases, for extended periods of time. The amount of plant installed to cover off risk factors and contingencies (for example, overload rated submarine cables with a spare cable, converter station pole overload, redundant auxiliary supplies, etc.) will mitigate these risks through appropriate design and specification.

The source documents for the development of probabilistic reliability models for the proposed Labrador-Island Link HVdc system are available but have not been updated with recent project definition parameters such as marine crossing details, length and reliability parameters of the transmission line, and configuration of the HVdc converter stations. The procedures and methodologies proposed by PTI for the development of the HVdc system reliability model are still valid and can be used for modeling the proposed Labrador-Island Link HVdc system with appropriate modifications such as HVdc converter station design layout, spare cable and SOBI crossing details, and transmission line design criteria.

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[101] Exhibit 106, Nalcor, “Technical Note: Labrador-Island HVdc Link and Island Interconnected System Reliability”, October 2011

Key findings of MHI's review of the reliability studies are as follows:

- The forced outage rates (FOR) assumed for various types of generating units are based on reliable sources and considered to be reasonable. The information documenting the derivation of the Labrador-Island Link HVdc system FOR of 0.89% on a per pole basis was not available for MHI's review. MHI has compared the Labrador-Island Link HVdc system pole FOR of 0.89% with published information and that of Manitoba Hydro's HVdc system and finds it within the normally accepted range. However, this FOR should be replaced by a more advanced and comprehensive reliability model incorporating all components of the Labrador-Island Link HVdc system.

- Probabilistic adequacy studies, including considerations related to transmission for comparison of the reliability of the two options, have not been completed by Nalcor. This is a gap in Nalcor's practices as various Canadian utilities including Manitoba Hydro, BC Hydro, Hydro Quebec, and Hydro One in Ontario have adopted these probabilistic methods for reliability studies for major projects. Probabilistic reliability methods utilize standard terms and indices such as Loss of Load Expectation, or Expected Unserved Energy, and make the risk analysis results plainly understandable in terms of dollars and/or loss of load.

  Deterministic assessments, such as those performed by Nalcor in Exhibit 106, cannot quantify the true risks associated with a power system and are unable to provide some of the important inputs for making sound engineering decisions such as risk and associated costs, including the potential large societal costs related to outages. Probabilistic assessment is a valuable means to assess system risk, reliability and associated costs/benefits for various system improvement options, particularly for major projects proposed by Nalcor. MHI has determined that choosing between the two options under review without such an assessment is a gap in Nalcor's work to date. Typically, these studies are completed at DG2. MHI recommends that these probabilistic reliability assessment studies be completed as soon as possible. Such studies should become part of Nalcor's processes that would allow for a comparison of the relative reliability for future facilities.

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4 Transmission Planning Criteria, AC Integration Studies, and NERC Standards

Report by: Alan Silk, P. Eng.

The ac system integration studies made available by Nalcor to MHI for review were conducted for the Gull Island Generating Station and the 3-terminal 1600 MW HVdc interconnector, with one termination at Soldiers Pond and another termination at Salisbury, New Brunswick (Exhibits CE-01 through CE-09). The project definition changed, in November 2010 following completion of the Nalcor project alternatives screening study (DG2) with Nalcor's decision to proceed with generation at Muskrat Falls using a point-to-point HVdc transmission system (Labrador-Island Link) with the inverter station at Soldiers Pond. There was insufficient information provided to form an opinion on the suitability of the ac system integration studies for the project, as redefined. However, MHI was able to examine the planning criteria in use at Nalcor and previous integration studies for Gull Island which noted some relevant ac transmission system issues.

4.1 Transmission Planning Criteria

The Planning Criteria is a policy document that will clearly identify the limits that trigger when new facilities need to be built, or when existing facilities need to be upgraded.

Planning criteria can be very prescriptive; however, as outside stakeholders can influence their application, the ideal document will have sufficient policy detail to direct staff and point to supporting external documents[102]. The application of Planning Criteria can also be influenced by corporate decisions or regulatory requirements. As an example, a utility may join a regional reliability group or sign an interconnection agreement that contractually obligates the parties to adhere to certain planning criteria.

Nalcor provided a document that describes the NLH and Nalcor power system planning criteria[103]. In this submission Nalcor not only provided the criteria, but also a self-assessment of their compliance. The criterion that was submitted is at a very high level and does not deal with the specifics. In some respects this is an ideal format as the corporate policies, guidelines, and standards that are required to adhere to the planning standards may have multiple stakeholders and are subject to change.

Exhibit 42 is an example of a document that supports the Planning Criteria. As an example, the Planning Criteria speaks to maintaining power flows at or below normal ratings for the equipment. How that criterion is accomplished for transmission lines is explained clearly in 3.2 of Exhibit 42[103]. This section identifies that there are three ratings: winter, summer/fall, and summer; and explains how they are developed. Of interest in this discussion is that the practice of defining three different ambient

[102] To inform stakeholders, many entities publish their Planning Criteria and supporting documentation on their external websites.
[103] Exhibit 42, Nalcor, "NLH 2009 Planning Criteria Review", 2009

temperatures is not an industry standard. However with the background provided in this document it is the appropriate practice in this situation.

Exhibit 42 refers to a second document titled “Bulk Power Systems Planning and Operations Criteria for Newfoundland and Labrador Hydro” which was developed by Power Technologies Incorporated in 1983. Exhibit 42 states that this document “has been considered to provide the framework for Hydro’s planning criteria and adoption of all criteria as the long term objective”. This is another document that needs to be referenced by the Planning Criteria as it will assist the person using the criteria understand how it is applied.

Ideally, planning criteria needs to be a high level document that directs the reader to supporting documentation or standards which identifies how the criteria will be met. Although some entities may not have published these documents, they will be the first to be examined following a major event, such as a black out that draws public attention. Therefore, many entities are now publishing some or all of these documents on their website.[104]

With the advent of open access interconnection tariffs, many entities have adopted the development of interconnection requirements to help third parties meet their planning requirements. For example, Manitoba Hydro publishes the “Manitoba Hydro Interconnection Requirements” report, which defines the conditions and requirements that an independent party must meet to obtain its *letter of commercial operation*[105]. The first page states that “Compliance with the technical requirements described in this document will ensure that facilities interconnected to the Manitoba Hydro Transmission System will comply with the planning criteria of Manitoba Hydro.” This document includes sections on:

- System Information and Design Practice
- Generation Interconnection Requirements
- Wind Generator Interconnection Requirements
- Customer Load Interconnection Requirements
- Transmission Line Owner Interconnection Requirements

The third revision of this document is publically available on Manitoba Hydro’s Open Access Same Time Information System page.

The format used by Nalcor could be improved by making references to its external and internal standards, guidelines, and policies; there is an example of this in Nalcor’s Transmission Planning Criteria. The distribution planning criteria for normal voltage makes reference to the CSA CAN3-C235-83 Standard and the CEA “Distribution Planner’s Guide”. The guide clearly states how Nalcor intends to apply these criteria while keeping the Distribution Planning Criteria at a high level. Applying this practice to the remainder of the planning criteria would be beneficial.

[104] For example Con Ed (NY) , AESO (AL) , CLECO (LA), and Eirgrid (Ireland)
[105] A letter of commercial operation is a document issued by a Tariff Administrator indicating agreement that compliance to all interconnection requirements are met under the applicable signed Interconnection Operating Agreement.

4.2 AC Integration Studies

Nalcor filed the following documents to describe the transmission assets required to support to the interconnections to Labrador and the Maritimes:

- Exhibit 23: Historical Summary of the Labrador-Island HVdc System Configuration for the Lower Churchill Project (1974-Present) – July 2011
- Exhibit CE31 Rev 1: Gull Island to Soldiers Pond HVdc Interconnection dc System Studies – December 1998
- Exhibit CE03/CE04: Lower Churchill Project DC1020 HVdc System Integration Study Volumes 1 and 2 – May 2008
- Exhibit CE10: Lower Churchill Project DC1210 HVdc Sensitivity Studies – July 2010

With the redefined project definition, these studies do not adequately describe the facilities required to successfully operate the transmission system under the new configuration. As such, there may be unidentified risks in proceeding with this project at this time. For example, the ac integration studies could identify requirements for additional back-up generation, new transmission lines, enhanced protection schemes or other system additions to maintain operation of the system at an acceptable level of performance. Such additions could add costs to the Infeed Option.

The response to RFI PUB-Nalcor-143 indicated that the ac integration studies for the current configuration would be completed by November 2011, which has now been delayed to the end of March 2012[106]. System integration studies completed as part of the project alternatives screening process, and provided to MHI by Nalcor, were for a Gull Island development with a 1600 MW three terminal HVdc system to Newfoundland and New Brunswick. Significant changes were made to the overall project definition with the proposed Muskrat Falls Generating Station development, and the deletion of the New Brunswick link. Good utility practice requires that these integration studies be completed as part of the project screening process (DG2); MHI considers this a major gap in Nalcor's work to date. These integrations studies must be completed prior to project sanction (DG3).

In the response to RFI MHI-Nalcor-39, Nalcor did supply a study plan which described the scope of work for the various ac integration studies[107]. It should be noted that this study plan does include the operation of the Maritime Link and contains: modes of operation, criteria, and a number of contingencies to test the performance of the integrated system. For example, a three-phase fault or slow clearing single-phase-to-ground fault close to the converter station could cause a temporary block of the Labrador-Island Link, which would impact the Newfoundland power system. Depending on the type of control systems employed in the Labrador-Island Link HVdc Link and the Maritime Link, remote faults off the Island of Newfoundland could cause oscillations on the Island of Newfoundland.

One would expect that there is a predefined set of disturbances in the Maritimes for all interconnection studies. If there is any possibility that the dynamic response from such disturbances

[106] Response to RFI PUB-Nalcor-143
[107] Response to RFI MHI-Nalcor-39

will be transferred into the study area, complete ac integration engineering studies should include a set of representative disturbances from outside the study area.

Although the studies filed to date cannot be used to validate the adequacy of the facilities required for these new interconnections, they did provide some insights on the dynamic issues of the island power system. Exhibit CE-03, filed by Nalcor in support of this project, included a number of recommendations:

- The effectiveness of power system stabilizers in the Newfoundland system should be investigated. This includes a review of the design and tuning of existing stabilizers and identification of potential new stabilizers that can benefit the overall small signal stability of the system.
- HVdc run-up and run-back schemes should be implemented to improve overall system stability. [108]

It is noteworthy that in the response to RFI MHI-Nalcor-39, the study scope supplied by Nalcor identified that in the event of a loss of the entire Labrador-Island Link HVdc link, the consultant was to assess the requirements for a special protection scheme for load shedding. Such a load shedding scheme could involve tripping “the Avalon, and potentially the Burin Peninsula depending upon system load conditions and HVdc Link load conditions”[109].

The documentation submitted to date has made reference to a 200% overload on the HVdc system for 10 minutes and a continuous overload capability of 150%. A 200% overload capability is a very good feature; however, it would require very dependable and fast-acting mitigation schemes, since the overload is only allowed for 10 minutes. As a 10 minute window for mitigating overloads is short, proposed mitigation processes should identify how the overload will be mitigated to the continuous overload capability of 150%. If the mitigation scheme depends on a third party, the third party should confirm that it is reasonable to assume that its mitigation plan can be put in place, even if details of the plans are in the formative stage. It should be noted that if an overload of more than 150% cannot be mitigated in 10 minutes, then load must be shed. In 2001, XCEL Energy developed a set of procedures called Fast Actions for Secure Transmission. In these procedures it agreed to run-back the Sherburne County Generating Station based on an event from a select list of area contingencies. Once reserves and congestion management processes could be enacted, the schedule at the station would be restored. The reason for implementing this procedure was in recognition of the fact that traditional mitigation schemes were not fast-acting enough to provide the relief needed.

Mitigating an overload below the continuous overload rating does not need this level of detail as the options available to the system control operators are greater. The continuous overload capability of 150% will be helpful in mitigating a significant number of contingencies that involve the loss of ac generation or dc system contingencies.

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[108] Exhibit CE-03 (Public) “Lower Churchill Project DC1020 HVdc System Integration Study - Volume 1”, May 2008
[109] Response to RFI PUB-Nalcor-31

4.3 NERC Standards

"Good Utility Practice" is a policy that most utilities recognize, either voluntarily or by regulation. The principle behind good utility practice is that electric utilities will adopt the practices and methods of a significant portion of utilities within a geographic boundary. For example, in Newfoundland and Labrador, good utility practice is defined in the Water Management Regulations, N.L.R. 4/09, s. 2(d) under the Electrical Power Control Act, 1994, S.N.L. 1994, c. E-5.1, s. 4. This regulation states that:

> *"'good utility practice' means those practices, methods or acts, including but not limited to the practices, methods or acts engaged in or approved by a significant portion of the electric utility industry in Canada, that at a particular time, in the exercise of reasonable judgment, and in light of the facts known at the time a decision is made, would be expected to accomplish the desired result in a manner which is consistent with laws and regulations and with due consideration for reliability, safety, environmental protection, and economic and efficient operations."*

This definition is substantially the same definition for all North American utilities that recognize and adhere to "good utility practice".

Since the August 14, 2003 blackout, most jurisdictions in North America, including at least eight provincial jurisdictions in Canada, have adopted the NERC standards as their reliability standards. In the US, this was accomplished through regulation. Following the release of the final report of the August 14, 2003 blackout in the United States and Canada, the US Federal Energy Regulatory Commission issued a Policy Statement[110] as follows: "In this Policy Statement, we clarify that the Commission interprets the term "good utility practice" to include compliance with NERC reliability standards or more stringent regional reliability council standards". In Canada, John Efford, Minister of Natural Resources, wrote a letter[111] with his US counterpart to the President of the United States and the Prime Minister of Canada. In it he states that, "The report makes clear that this blackout could have been prevented and that immediate actions must be taken in both the United States and Canada to ensure that our electric system is more reliable. First and foremost, compliance with reliability rules must be made mandatory with substantial penalties for non-compliance." In September 2006, the National Energy Board (NEB) recognized NERC as the Electric Reliability Organization[112]. In the News Release announcing this action, NEB Chairman Kenneth Vollman stated that, "We've been long-time supporters of mandatory reliability standards for international power lines and by recognizing NERC as the single ERO in North America; we've taken an important step towards strengthening that goal." This common action in the USA and Canada allows NERC's reliability standards to meet the requirement of being a practice that is consistent with the methods or acts engaged in or approved by a significant portion of the electric utility industry, even if the scope of those methods or acts is limited to Canada.

In Canada, eight of the ten jurisdictions have accepted NERC standards as their reliability standards. It may be understood that these eight jurisdictions have adopted mandatory standards with penalties solely because of interconnections with the USA. However, Alberta has no interconnections with the

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[110] FERC Docket PL04-5-000 before Commissioners Pat Wood, III, Chairman, Nora Mead Brownell, Joseph T. Kelliher, and Suedeen G. Kelly "Policy Statement on Matters Related to the Bulk Power System Reliability"," April 2004
[111] U.S.-Canada Power System Outage Task Force, "August 14th Blackout: Causes and Recommendations,"March 2004
[112] National Energy Board, " News Release 06/23", September 2006

USA, Quebec is dynamically isolated from the eastern interconnection, and Saskatchewan is virtually isolated from the USA through a single tie with phase shifter control, these jurisdictions had their own reasons for subjecting their utility's provincial operations to NERC standards with penalties for non-compliance.

The Nova Scotia Utilities and Review Board issued an order on the application by North American Electric Reliability Corporation on July 20, 2011. This order adopts and puts in force NERC Standards for Nova Scotia Power Inc. where the Standards and Criteria are mandatory and enforceable for users, owners and operators of the bulk power system in Nova Scotia. Thus the NERC reliability standards and NPCC regional reliability criteria are mandatory in Nova Scotia.

As Alberta has no ties to the US, one may consider it similar to Newfoundland and Labrador in power system operations. The Alberta Electric System Operator has adopted the mandatory use of NERC standards for use within Alberta. As a number of reliability standards have no application in Alberta due to its isolation from the USA, they have decided not to enforce all the NERC standards. Presently there are 43 non-applicable standards listed on their website[113].

With near unanimous acceptance of mandatory standards with penalties within Canada aimed at increasing the reliability of the provincial networks within Canada, it is hard to justify that NERC standards are not a practice, method or act approved by a significant portion of the electric utility industry in Canada. Therefore any utility that is assessing their adherence to "Good Utility Practice" must consider their adherence to NERC Standards.

NERC grades system operations into four categories with Category A being all facilities in service with no disturbance, to Category D which is an extreme event with two or more elements removed or elements cascading out of service. The allowable mitigations to a Category D contingency does allow for angular instability. Listing the operating condition and contingency as Category D does not allow the transmission owner to disregard the disturbance. NERC requires that Category D contingencies be assessed annually and be acceptable to the associated Regional Reliability Organization[114]. NERC also requires that Category D scenarios be studied from years one through five, with all firm transfers modeled, and all existing and planned facilities included.

NERC transmission planning standards list a 3 phase fault as a Category B contingency.[115] A category B contingency must maintain a stable system where both the thermal and voltage limits are within applicable ratings. The loss of demand, curtailing of firm transfers, or cascading outages are not acceptable outcomes for this contingency. Nalcor has stated that it does not plan to address a 3 phase fault at Bay d'Espoir as the present system fails to maintain angular stability following this contingency under some operating conditions[116]. As the system response to this disturbance falls outside of the requirements for NERC Standards and therefore outside of the definition of "Good Utility Practice", Nalcor's response to this situation is not aligned with utility best practice.

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[113] http://www.aeso.ca/
[114] TPL-004-1, "System Performance Following Extreme BES Event – Version 1", February2011
[115] TPL-002-0b, "– System Performance Following Loss of the Single BES Element-Version 0b – Approved", November 2009
[116] Response to RFI MHI-Nalcor-83

Nalcor could decide to place three phase faults into Category D, instead of NERC's classification as a Category B disturbance; there would be obvious financial benefits to this decision. A Category B disturbance has a performance specification that would have to be met while a Category D disturbance would only be presented to demonstrate what would happen if the disturbance were to occur. However neither category can be ignored and must be studied. Even if the system is allowed to become unstable following a three phase fault, it is important that the magnitude of the instability be demonstrated. Are the effects of the disturbance only local to the disturbance or do they have wide ranging impacts? For example, for a three phase fault at Bay d'Espoir, angular instability will occur under some operating conditions. If out of step relays employed to detect that angular instability and cause an orderly separation, will the addition of new facilities impact the ability of the out of step relays to perform their function? Electing to not consider the impact of disturbances in studies, even if the disturbance does not require an investment to mitigate, is never a good practice.

Nalcor has stated that the Emera Maritime Link will be built and operated in compliance with the applicable NERC standards. However, for Newfoundland

> *"the Government of Newfoundland and Labrador has not established a role for NERC within the province. As a result, the interconnection of the Maritime Link to the Island Interconnected System and the facilities of Newfoundland and Labrador Hydro will be approved by Hydro. Hydro's reliability, design, and operational criteria will apply to the Newfoundland side of the interconnection."*[117]

As a result Nalcor currently does not comply with NERC standards.[118,119] A majority of utilities in Canada have adopted the definition of "good utility practice" that incorporates adherence to NERC standards. Also, should the Maritime Link proceed, and Nalcor participates in the electricity marketplace, it is MHI's opinion that NERC standards will ultimately apply. It would be prudent for Nalcor to complete a self-assessment and prepare for compliance to NERC standards as NERC standards will apply to the Labrador operations of the Lower Churchill Project.

4.4 Conclusions and Key Findings

Nalcor provided a number of documents in the areas of transmission planning criteria, ac integration studies, and NERC standards as they relate to good utility practice, which were reviewed by MHI.

The transmission planning criteria provided by Nalcor for review is a key document that clearly identifies the operating limits that trigger when new transmission facilities are required, or when existing facilities need to be upgraded when violated. MHI reviewed the transmission planning criteria and found this document appropriate.

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[117] Response to RFI PUB-Nalcor-140
[118] Exhibit 106, Nalcor, "Technical Note: Labrador –Island HVdc Link and Island Interconnected System Reliability", October 2011
[119] Response to RFI PUB-Nalcor-164

The final ac integration studies for the Labrador-Island Link HVdc system were not available for review. As a result, the following key finding is noted:

- System integration studies completed as part of the project alternatives screening process, and provided to MHI by Nalcor were for a Gull Island development with a 1600 MW three terminal HVdc system to Newfoundland and New Brunswick. Significant changes were made to the overall project definition with the proposed Muskrat Falls Generating Station development, and the deletion of the New Brunswick link. Integration studies that would support the changes have not been completed and Nalcor now advises that the studies will not be available until March 2012[120]. As the full requirements for integration of the Labrador-Island Link HVdc system are not known, there may be additional risk factors that may impact the cumulative present worth of the Infeed Option. For example, installation of backup supplies to cover operational limitations in the Labrador-Island Link HVdc system may be required, and additional transmission lines may be needed to maintain acceptable system performance. Spare equipment requirements also need to be taken into consideration. Good utility practice requires that these integration studies be completed as part of the project screening process (DG2). MHI considers this a major gap in Nalcor's work to date. These integrations studies must be completed prior to project sanction (DG3).

Through MHI's review of the documentation, and related RFIs noted in the report, the issue of NERC Standards was noted as a concern, particularly with new interconnections planned from the Island of Newfoundland to Labrador, and from the Island of Newfoundland to Nova Scotia. The key finding from the NERC Standards review is as follows:

- MHI finds that Nalcor currently does not comply with NERC standards. A majority of utilities in Canada have adopted the definition of "good utility practice" that incorporates adherence to NERC standards. Also, should the Maritime Link proceed, and Nalcor participates in the electricity marketplace, NERC standards will ultimately apply. MHI recommends that Nalcor complete a self-assessment and prepare for compliance to NERC standards with or without the Maritime Link.

[120] Response to RFI PUB-Nalcor-143

5 Muskrat Falls Project

Report by: P. Rae, P. Eng.

5.1 Introduction

The Muskrat Falls Project comprises the hydropower generation facility proposed on the Lower Churchill River. The main project elements include: a 824 MW power station with four turbine-generator units, a concrete gravity dam, spillway, abutment stabilization works, a substation, and facilities for interconnection with the high voltage transmission links.

Planning and development of the Project has progressed during a long time span with studies performed initially in the mid 1960's and continuing to 2011. The characteristics of the project have changed and evolved during this period in response to circumstances and differences in the assumed market for connection of the Project.

The history of the development includes the following main steps:

- The first assessment of power sites on the Lower Churchill River was prepared for development of the Upper Churchill Falls project during the 1960's. The studies at that time were limited in scope with only reconnaissance surveys and some field investigations.
- A review was commissioned in 1975 for the Gull Island Power Company Limited that suggested changes to the layouts and identified a program of more detailed field investigations.
- In 1977, Newfoundland and Labrador Hydro commissioned further field work and an update of previous preliminary layouts and cost estimates.
- Additional work was carried out in 1979 as part of engineering studies for the full Lower Churchill project development. The work included definition for a detailed exploration program at Muskrat Falls, study of alternative intake and powerhouse designs, review of ice studies and diversion works, review of the design floods and additional studies on schedule and support requirements.
- Subsequently in 1979, the Lower Churchill Development Corporation arranged for completion of the detailed field investigation program and an engineering study for the potential development of Muskrat Falls. As a result of this study, it was established that development of the Muskrat Falls site with a capacity of 618 MW was technically feasible. The engineering report was completed in March, 1980. Alternative project layouts were developed and a recommended variant was selected.
- The 1979 study also included an investigation into the stabilization requirements for the north spur at the Muskrat Falls site, which was identified as a geotechnical formation requiring careful consideration for the project. Recommendations were made to resolve any concerns for the north spur.
- In 1989, a supplemental development layout study of the Muskrat Falls site was prepared with a total installed capacity of 824 MW. The higher installed capacity resulted from a project

optimization study that considered Muskrat Falls as part of an integrated development of the Lower Churchill, leaving the Upper Churchill Project for energy exports.

- In 1998, Newfoundland and Labrador Hydro commissioned the preparation of a final feasibility study which comprised a review of the previous studies, further site investigations and the determination of the preferred solution for development of the Muskrat Falls site.
- In association with the feasibility study, a companion study was prepared in 1999 to optimize the installed capacity of the project as part of a Lower Churchill River development. This study verified the selection of the 824 MW installed capacity.

All of the preceding studies were performed on the basis of the Muskrat Falls project being constructed after completion of the Gull Island hydroelectric project upstream.

The program for development was changed subsequent to the completion of the feasibility study with the main rationale being the requirement for commercial sales to the Island. The project development scheme is now based on implementation of the Muskrat Falls project as a first stage, with power sales to Newfoundland and Labrador rather than using the Hydro Quebec transmission system to sell power. This important change required that many aspects of the project be updated. A series of studies were carried out in 2010 and 2011 to establish the new engineering and technical basis for the project. Nalcor Energy has also adapted many aspects of the project to suit long term operating conditions and internal preferences for some aspects of the development. The following sections describe the proposed project in more detail.

5.1.1 Muskrat Falls Development

The Muskrat Falls development was originally conceived as one element of the overall development of the Lower Churchill River and associated expansions upstream. The configuration included expansion of the Upper Churchill project, upstream Quebec river diversions that would supplement the inflow to the Upper Churchill reservoir, and the Muskrat Falls and Gull Island projects on the Lower Churchill. The Muskrat Falls project was originally selected for development following completion of the Gull Island project, and as result, some design and construction conditions were changed to accommodate proceeding with Muskrat Falls first.

The Muskrat Falls project was ultimately selected in 2010 to be completed as the first stage of the Lower Churchill River development, with the Gull Island Project to follow when market conditions permit. Nalcor conducted a series of supplemental studies as necessary to reconfigure the project for development as the first stage before undertaking the Gull Island project. The studies updated information such as the design flood, ice conditions, dam break, firm and average energy, construction planning, and design variant. The characteristics such as the powerhouse, the spillway and the non-overflow dam of the power facilities have been modified slightly as part of the updates. Changes have largely been related to details of the dam, ice management, and sequencing of construction that affect the Muskrat Falls project. Of three variants considered for the project, the one selected was primarily the result of a bridge project spanning the Churchill River, which made access to the south shore possible.

Engineering and design of the project is reported to be in progress with the final configuration selected by Nalcor. The Project, as now envisaged, differs in some respects from the configuration presented in the technical studies. Selected deviations were discussed with Nalcor and explanations were provided during the review process. Further discussion of these results is provided in the following paragraphs.

5.1.2 Scope of Review

MHI's technical review of the proposed Muskrat Falls development included:

- Review the proposed project layout and characteristics to identify any factors that might preclude successful development of the site;
- Confirmation that the scope of work for the project is comprehensive as a basis for planning and cost estimates;
- Assessment of the methods used for preparation of the project cost estimates and confirmation that the estimates are reasonable;
- Evaluation of the time period allocated for construction; and
- A review of the values derived for the generating capacity and energy.

Where appropriate, the outcomes from the above tasks have been used as input to the CPW analysis. The following sub-sections summarize the review of the Muskrat Falls project.

The review was not intended to be exhaustive but is sufficient to ensure that the decisions and recommendations reached for development of the project are well founded on factual and appropriate information.

5.1.3 Methodology

The documents listed in Table 20 were provided by Nalcor and examined for this review.

With respect to the project cost estimate and the project control schedule, the information collection was performed largely by interviews with Nalcor staff. The details relating to the cost, contract strategy, and scheduling of the project are considered by Nalcor to include commercially sensitive information that could affect the contracting process and accordingly have not been included in detail in this document.

Table 20: Muskrat Falls Documents Reviewed

Exhibit	Title	Prepared by	Date
17	Churchill Falls Water Management Agreement	Nalcor Energy	2009
19	Muskrat Falls Final Feasibility Study	SNC-Agra	1999
31	Lower Churchill Project Cost Estimate Progression 1998 to 2011, Technical Note	Nalcor Energy	July 2011
38	Lower Churchill Falls Project, Muskrat Falls North Spur, 1999 to 2011	Nalcor Energy	July 2011

Exhibit	Title	Prepared by	Date
39	Lower Churchill Falls Project, MF 1260, Assessment of Existing Pumpwell System	Hatch in association with RSW and Statnett	July 2008
40	Lower Churchill Project, MF 1271 – Evaluation of Existing Wells, Pumps and Related Infrastructure in the Muskrat Falls Pumpwell System	Hatch	March 2011
41	Lower Churchill Project, MF 1272 – Installation of New Piezometers in the Muskrat Falls Pumpwell System	Hatch	April 2010
CE-15 Rev.1 (Public)	Muskrat Falls Hydroelectric Project, MF 1010 – Review of Variants	SNC Lavalin	March 2008
CE-16 Rev.1 (Public)	Muskrat Falls Hydroelectric Project, MF 1050 – Spillway Design Review	SNC Lavalin	December 2007
CE-17 (Public)	Lower Churchill Project, MF 1130 – River Operations During Construction and Impoundment	Hatch in association with RSW and Statnett	January 2008
CE-18 (Public)	Muskrat Falls Hydroelectric Project, MF 1250 – Numerical Modeling of Muskrat Falls Structures	SNC Lavalin	May 2008
CE-19 (Public)	MF 1300 – Muskrat Falls 2010 Site Investigation, Volume 1	SNC Lavalin	June 2011
CE-20 Rev.1 (Public)	MF 1310 – Muskrat Falls Site Access Review	SNC Lavalin	February 2011
CE-21	Lower Churchill Project, MF 1320 – Estimate of Firm Energy Potential of the Muskrat Falls Development	Hatch	June 2011
CE-22 (Public)	Lower Churchill Project, MF 1330 – Hydraulic Modeling and Studies, 2010 Update, Modeling of the River, Report 1	Hatch	October 2010
CE-23 (Public)	Lower Churchill Project, MF 1330 – Hydraulic Modeling and Studies, 2010 Update, Muskrat PMF and Construction Design Flood Study, Report 2	Hatch	December 2010
CE-24 (Public)	Lower Churchill Project, MF 1330 – Hydraulic Modeling and Studies, 2010 Update, Dam Break Study, Report 3	Hatch	December 2010
CE-25 (Public)	Lower Churchill Project, MF 1330 – Hydraulic Modeling and Studies, 2010 Update, Muskrat Falls Ice Study, Report 4	Hatch	March 2011
CE-26	Lower Churchill Project, MF 1330 – Hydraulic Modeling and Studies, 2010 Update, Muskrat Falls Regulation Study, Report 6.	Hatch	May 2011
CE-27 Rev.1 (Public)	CE 202-120142-00007, Muskrat Falls Hydroelectric Development, Summary of Studies on Firm and Average Energy Production	Nalcor Energy	June 2011
CE-28 Rev.1 (Public)	Churchill River Complex: Power and Energy Modeling Study	Acres International Limited	July 1998
CE-29 Rev.1 (Public)	Churchill River Complex Optimization Study, Optimization Study, Volume 1, Main Report	Acres International Limited	January 1999
CE-30 Rev.1 (Public)	Churchill River Complex: Power and Energy Modeling Study, Final Report. Optimization Study, Detailed Models, Volume 2	Acres International Limited	July 1998
CE-52 Rev.1 (Public)	Technical Note – Strategic Risk Analysis and Mitigation	Nalcor Energy	2010

Exhibit	Title	Prepared by	Date
CE-54 Rev.1 (Public)	GI1141 –Upper Churchill PMF and Flood Handling Procedures Update	Hatch in association with RSW Inc, and Statnett	August 2009
CE-51 Rev.1 (Public)	Muskrat Falls Generating Facility and Labrador-Island Transmission Link, Overview of Decision Gate 2 Capital Cost and Schedule Estimates, Technical Note	Nalcor Energy	August 2011

5.2 General

Detailed design of the Project has now been assigned to an EPCM (Engineering, Procurement and Construction Management) consultant that is working to prepare for project sanction (DG3). A Technical Note[121] was prepared by Nalcor which summarizes the main changes from completion of the feasibility study and contains a list of the key characteristics to be used by the EPCM consultant.

The following paragraphs summarize the Project as interpreted from the available reference documents and discussions with Nalcor staff.

5.3 Project Design and Construction Considerations

5.3.1 Project Site

The Muskrat Falls site is described in the Final Feasibility Study[122] with access details updated in the Muskrat Falls Site Access Review[123]. Topographic features of the site include the two stage waterfall in the main river channel, a high rock knoll on the north shore, and a clay spur extending from the rock knoll to the valley slope.

Topographic investigations for the site appear to be complete and include site mapping, bathymetric surveys, and feature location surveys. The surveys performed, as well as the hydraulic and ice studies, all support the site layout and design.

The general geotechnical and geological characteristics of the site are described in the Muskrat Falls Final Feasibility Study. Additional studies have also been carried out following the feasibility study to supplement data in areas where specific issues were identified. A significant investigation effort has

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[121] Exhibit 30, Nalcor, "Technical Note: Lower Churchill Design Progression 1998 to 2011", July 2011
[122] Exhibit 19, SNC-Agra, "Muskrat Falls Hydroelectric Development, Final Feasibility Study Volume 1 – Engineering Report", January 1999
[123] Exhibit CE-20 Rev.1 (Public), SNC-Lavalin, "Technical Report, MF1310 – Muskrat Falls Site Access Review", February 2011

been undertaken for the north spur zone as described in the Technical Note: Muskrat Falls North Spur.[124]

All investigation programs have been carried out using qualified consulting engineering firms. The programs were defined to allow for the collection of data and supplemental investigations were undertaken to clarify conditions found in the field.

During the geotechnical investigations, the site was reviewed in sufficient detail to allow for feasibility assessment, preliminary design, and cost estimates, which support the decisions required. Additional investigations may be undertaken for detailed design; however, there is no reason to believe that the site conditions would preclude successful development of the hydropower station.

Access to the site is available from the Trans Labrador Highway and with completion of a bridge across the Churchill River, access is now possible to both banks of the river.

Topographic and geotechnical conditions have been identified and site construction can begin as planned.

5.3.2 Installed Capacity

The installed capacity and arrangement of the Muskrat Falls and Gull Island projects were most recently optimized for the Final Feasibility Study as part of an integrated system plan, including the Upper and Lower Churchill River.

The selected installed capacity of 824 MW is associated with firm energy of about 4.5 TWh/yr and average energy of 4.9 TWh/yr. The plant capacity factor is about 68% for the arrangement selected and this is consistent with run of the river hydro power projects. The power station can, therefore, operate primarily as a base and intermediate load energy producer with peaking power to be provided by other plants on the island. Details of the utilization of the available power and energy from the Project are incorporated in the power systems studies reviewed in other sections of this Report.

The installed capacity of the Project was originally[125] optimized for the Lower Churchill Falls development, comprising Muskrat Falls and Gull Island, integrated with Upper Churchill Falls and other projects in Quebec, to supply power and energy to the Hydro Quebec system.

5.3.3 Site Layout and Access

The Final Feasibility Study provided a comprehensive review of the conditions affecting the layout of the site. However, an important update of this study was conducted in 2010, which was based on the original plan and several adjustments to suit conditions that had changed from the end of the Feasibility Study. The most important of these adjustments are summarized in the following paragraphs.

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[124] Exhibit 38, Nalcor, “Technical Note: Lower Churchill Project - Muskrat Falls North Spur 1999 to 2011”, July 2011
[125] CE-29 Rev.1 (Public), Acres International, “Churchill River Complex Optimization Study”, January 1999

Each of the studies to date have adopted similar water level criteria. The downstream water level is governed by the natural water level of the Churchill River below Muskrat Falls. The upstream water level is limited by the assumed tailwater level for the future Gull Island development. With Muskrat Falls developed in isolation, the upstream water level could be higher. However, this would restrict the possible future output from the Gull Island project. The decision to restrict Muskrat Falls to a maximum level consistent with future Gull Island development is considered to be appropriate.

Diversion of the river during construction in the Final Feasibility Study considered the use of tunnels. However, more recent studies have demonstrated that an open channel river diversion can be used effectively at a lower cost. The water flow is initially left in the existing river channel, while the spillway is constructed behind a cofferdam; the river is then diverted through the spillway while the main gravity dam section is completed. The powerhouse is constructed outside of the existing river bed where it can be isolated by cofferdams for the full construction period.

The project is being developed with a small reservoir for run of river operation. The reservoir level at the site will fluctuate within a range of 500 mm as needed to accommodate small variations in river flow or turbine-generator loading.

The studies carried out to select the general arrangement of the permanent works appear to be comprehensive and to provide a reasonable conclusion for the optimum development in terms of cost and construction duration. Topographic, geotechnical, hydrologic, and hydraulic conditions have been considered to select the optimum site layout. The studies have been performed by consulting engineering firms with extensive relevant experience with similar projects and in accordance with good utility practice. The selected arrangement of the site is consistent with common hydroelectric power project layouts.

5.3.4 Dam and Spillway

Concrete dams were selected to close the river to the north and south of the powerhouse block. A spillway structure is included between the north dam and the powerhouse block.

The north dam is configured as a concrete gravity section with a free overflow spillway located along part of the crest. Roller compacted concrete construction is planned to allow for rapid completion of the structure within two summer seasons. Roller compacted concrete construction methods are appropriate for modern concrete dams although careful preparation of the site and mobilization of the necessary production facilities will be required. Planning activities by Nalcor appear to recognize the requirements and are believed to provide a good foundation for project development and construction.

The south dam is located outside of the existing river valley and closes the valley from the south end of the powerhouse block. The south dam will also be a concrete gravity structure that will be constructed with roller compacted concrete. The dam is now designed as a non-overflow section that will retain water levels up to the probable maximum flood. The south dam can be constructed without any diversion of the existing river channel.

Spillway facilities comprise a gate controlled structure located between the north dam and the powerhouse and a free overflow spillway on the crest of the north dam. The gate controlled spillway will be used for the release of river flow in excess of the amount required for power generation. The free overflow spillway will be used during floods exceeding the discharge capacity of the spillway and possibly in the event of unusual conditions such as unavailability of a gate or full load rejection of the power station.

The main spillway has four submerged radial gates located in a structure adjacent to the north end of the powerhouse. The spillway arrangement selected for the final design differs from the Final Feasibility Study, as described in a final optimisation study completed in 2011.

The diversion scheme proposed appears to be practical and consistent with the construction program. Studies have been undertaken to assess the effect of ice on the cofferdams and water levels at the construction site. The ice analysis has been updated to represent the final arrangement of structures proposed.

The layout and dimensions of the structures were selected as part of the Final Feasibility Study and the subsequent project optimization update studies. The layout of the dam has been prepared by experienced consulting firms and appears to be consistent with the conditions at the site and hydropower industry practice. The north spur structure at the site is a natural dam that extends from the rock knoll adjacent to the main river channel northwards across the valley. The spur comprises a soil and rock formation derived from the geological history of the site. The bedrock foundation is deep and extends below the river bed level. The Final Feasibility Study focused on the stability and water tightness of the north spur.

The possibility of instability of the north spur under reservoir loading was identified early and analysed to develop a remedial works program. This consisted of installation of dewatering wells that reduce the phreatic surface in the soil, with the result that the factors of safety are increased. The well program has been examined during subsequent technical studies, and the consultants have confirmed the satisfactory operation of the pump wells[126] to date. Stability of the north spur relies on the well system to manage the phreatic surface through the structure along with remodelling of the topography to reduce the loading on the slopes. The Final Feasibility Study included an analysis to substantiate the design concept but the detailed design studies must demonstrate the long term viability of this concept[127]. The long term viability of this scheme is subject to further analysis and detailed design of the necessary stabilization works.

Design for the permanent works includes the extension of the de-watering well system by increasing the number and extent of the wells. Some local excavation will be undertaken to lower the height of the ridge, thereby reducing the loading on slopes.

The consultants involved have undertaken a comprehensive review of the stability of the north spur including the response of the structure to changes in water levels. There is no reason to believe that the north spur would not be stable during the life of the project.

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[126] Exhibit 40, Hatch, “Lower Churchill Project, MF1271 – Evaluation of Existing Wells, Pumps, and Related Infrastructure in the Muskrat Falls Pumpwell System”, March 2010

[127] Exhibit 38, Nalcor, “Technical Note: Lower Churchill Falls, Muskrat Falls North Spur 1999 to 2011”, July 2011

Based on the information provided, the design and construction of the Muskrat Falls works is consistent with good engineering and construction practices and should not pose any unusual risks for the construction or operation of the facilities.

5.3.5 Powerhouse Arrangement

The powerhouse is designed with four turbine-generator units using a concrete spiral case arrangement. The structure integrates the intake, turbine and draft tubes. The arrangement proposed is a conventional approach for low head hydropower stations. Precedents for the use of this arrangement with similar sized turbines were provided as part of the Feasibility Study.

The powerhouse arrangement considered provisions for the erection and operation of the turbine generator units. Several adjustments to the arrangement were made in the various update studies (see Table 1) performed after the completion of the Final Feasibility Study. Updates were prepared between 2007 and 2010. Adjustments included selection of four Kaplan turbines in place of the original arrangement with three propeller turbines and one Kaplan. Other adjustments were to details of the powerhouse layout, spillway, ice management, site access, and river diversion, which influenced the powerhouse location and layout. The final arrangement of the powerhouse will be determined during the ongoing design studies by the selected EPCM consultant. However, there is no evidence to suggest that the powerhouse arrangement represents any unusual risks or incorporates any abnormal features.

5.3.6 Generating Equipment

Four Kaplan turbine-generator sets are proposed for the development, which is a deviation from the arrangement of three propeller and one Kaplan proposed in the Final Feasibility Study. The turbine arrangement was selected by Nalcor as an optimization considering long term reliability, maintenance, powerhouse structure design, shipping dimensions, and other factors. The use of the four Kaplan units has a slightly higher capital cost than the propeller units but this is compensated by savings in the civil works, improved energy yield, and the other factors examined.

The selection of Kaplan units is a conventional choice for the head and discharge conditions at Muskrat Falls. The arrangement is not believed to pose any unusual design, construction, or operating risks. Several well qualified manufacturers are available for this equipment, which should allow for competitive pricing for equipment procurement.

5.3.7 Switchyard and Transmission Interconnection

A switchyard will be located at the Muskrat Falls site for interconnection of the power station with the transmission system. The system comprises a 345 kV switchyard at the Muskrat Falls station, a 345 – 138 kV substation located about five kilometers from the station, 245km of 345 kV ac transmission to the Upper Churchill Falls substation, the 345 kV ac – dc converter station, and the 1100 km dc link to the island and inverter station at Soldiers Pond. In addition to the Island Link, the Project reinforces the existing transmission system in Labrador.

The transmission and stations proposed are believed to be consistent with the requirements for the project. There is no reason to expect any unusual risks or difficulties with the arrangement when the final design is prepared by the EPCM consultants.

5.3.8 Project Construction

The studies performed to date have identified sources for construction materials in the vicinity of the site. Access routes have been identified and assessed for materials and equipment, including for the movement of large scale components such as transformers, generator components, and turbines. Nalcor has assessed the equipment and labour required for construction and planned the site development activities to accommodate the required facilities and accommodations. The schedule has been modified to recognize that some construction works will be sensitive to the winter weather conditions.

Work has been scheduled for construction of facilities using conventional and proven methods. There is no reason be believe that the construction of the facilities proposed would result in unusual risks for cost escalation or time extensions.

5.4 Construction Schedule

A Project Control Schedule was used to plan the implementation of the works and as a basis for the detailed cost estimate prepared for the project by Nalcor. The cost of the works will be directly affected by the project schedule, which will determine the time available for each task, flood risk exposure, the need for any winter season work and other details influencing work productivity, such as labour force loading, and equipment utilization. Resource levelling through the construction schedule can have a significant effect on cost.

The Final Feasibility Study schedule was prepared on the assumption that access would only be available from the north bank of the river during the first year. However, the Final Feasibility Study was substantially superseded when access across the Lower Churchill River downstream from the site allowed for a new site layout variant to be selected.[128] The selected variant allowed for a substantial reduction in the duration of construction by making use of the access along the south bank of the river to expedite the powerhouse construction.

The final project variant was selected on the basis of the improved construction schedule, lower construction risks, and the comparative cost of the works. A final project control schedule was prepared by Nalcor for the works[129] on the basis of the selected project arrangement. The project control schedule updates the assumptions about the sequence of the construction works by including the selected contract strategy and the work breakdown structure adopted for the base construction estimate. MHI finds that the project control schedule is appropriate for DG2.

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[128] Exhibit CE-15 Rev.1 (Public), SNC Lavalin, “Newfoundland and Labrador Hydro Lower Churchill Project Pre-feed Engineering Services, Muskrat Falls Hydroelectric Project - MF1010 – Review of Variants”, March 2008

[129] Exhibit CE-51 Rev.1 (Public), Nalcor, “Technical Note: Muskrat Falls Generation Facility and Labrador – Island Transmission Link - Overview of Decision Gate 2 Capital Cost and Schedule Estimates”, August 2011

5.4.1 Work Breakdown Structure and Contract Packaging

The Project Control Schedule was determined from a Work Breakdown Structure (WBS) that is reported to include all elements of the scope of work. During an interview, Nalcor outlined the contract strategy including separation of the scope of work into contract packages. The WBS allows for the construction activities to be divided into logical packages for planning and cost estimating.

The preliminary contract packaging has been prepared by Nalcor based on the WBS, the character of the works, and the anticipated capacity of contractors. The contracts identified appear to be logical and consistent with the strategy devised by Nalcor for construction.

The WBS appears to be sufficiently detailed to allow for a comprehensive assessment of the project schedule and cost. The WBS has taken into consideration activities necessary for construction of the project.

5.4.2 Project Control Schedule and Construction Duration

The Project Control Schedule provides a basis for the detailed project cost estimate. The schedule was developed from the WBS and considers the site conditions, climactic conditions, site access, constraints, and other factors relevant to the works. The schedule updates the work presented in the previous Study – Review of Variants, which included the comparative schedules described above.[130] The final project control schedule is adequate for construction planning, management of the works, and for the cost estimating activities. The schedule will be updated as contract packages are awarded and the final construction schedules are established.

An effort has been made to level activities through the construction period to reduce variations in the work load, to minimize interface difficulties among contractors, and to balance the labour force. The activity leveling process affects the cost estimate by reducing indirect costs for items such as labour camps and equipment.

The resulting project control schedule has about 750 activities and is structured according to the proposed contracting strategy. The activities selected appear to represent the full scope of work and to constitute a logical sequence of work.

Based on the information available, the overall construction duration is believed to be reasonable. Work is planned by contract packages with awards being timed as required and in consideration of site conditions.

[130] Exhibit CE-15 Rev.1 (Public), SNC Lavalin, "Newfoundland and Labrador Hydro Lower Churchill Project Pre-feed Engineering Services, Muskrat Falls Hydroelectric Project - MF1010 – Review of Variants", March 2008

5.5 Base Cost Estimate

The final Base Cost Estimate was prepared by Nalcor Energy as described in a confidential detailed estimate report[131]. Nalcor considers these estimates to be commensurate with an Association for the Advancement of Cost Engineering (AACE) Class 4 estimate (Exhibit 31).

Nalcor concluded that, since the increase in costs between the interim and final Base Cost estimates for Muskrat Falls was essentially offset by a decrease in the Base Cost for the Labrador – Island Transmission Link, the change in Base Costs for Muskrat Falls was not material.

The absolute value of the construction cost estimate has been determined by using the procedure adopted by Nalcor to determine the Base Cost Estimate.

Nalcor's DG2 capital cost estimate was prepared as a "bottom up" estimate considering the construction productivity and schedule along with the cost of materials, equipment and labour required for construction. The WBS was used as basis for the estimate. The procedure defines work activities for each element of the construction, assigns crews and equipment for the activities, and then determines the cost by estimates of the crew productivity for each activity.

A review of the Nalcor estimate was prepared by examining some of the inputs to the analysis and by comparison with similar projects within the experience of the reviewer. The review was not performed as an independent cost estimate, nor was it performed as a peer review of the Nalcor estimating procedures. The review outlined in the following paragraphs considers the main elements of the estimating procedures. The cost estimate was prepared using an appropriate methodology that was applied in a comprehensive manner with relevant input data and assumptions. The resulting estimate of costs is believed to provide a reasonable valuation for the Project cost.

5.5.1 Cost Estimate Methodology

The overall methodology for the cost estimate derives a detailed Work Breakdown Structure that includes all elements of the scope of work. The WBS was then used to allocate costs to either equipment procurement or civil works construction activities. The approach adopted is in accordance with the recommended estimating practices of the AACE.

Equipment procurement costs were estimated by reference to supplier quotations, estimator's experience, and industry benchmarking. These costs were defined by the cost estimator according to the WBS structure.

The civil cost elements were determined by considering the construction method and costs associated with each of the WBS items. The procedure involved identification of the construction crew, labour productivity, material inputs, and other costs required to complete the work identified. Detailed construction quantity takeoffs were required to measure the amount of work to be performed within the time allocated in the project control schedule.

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

Nalcor has adopted the use of cost estimating software packages that facilitate the handling and management of the information required for the analysis. The procedure requires the estimation of a large number of parameters and the formulation of assumptions that pertain to the valuation. Importantly, the strategy for construction of the project must be determined and a construction schedule developed.

A general description of the cost estimate methodology is presented in a technical note by Nalcor[132]. The overall cost estimate methodology is appropriate for a major construction project and would allow for a reliable estimate provided that the inputs to the analysis are meaningful. The following paragraphs provide further information on the assessment of the Nalcor cost estimates.

5.5.2 Construction Labour Rates

Labour rates are an important part of the overall construction costs. The WBS included with the Project Control Schedule was used to determine the labour force loading for the construction period. The tradesmen required for construction were then determined along with the man hours allocated and their scheduling. Identification of the required trades provides the basis for the evaluation of labour costs.

Nalcor determined the cost of labour inputs to the estimate based on other large projects in the region with adjustments for the anticipated site conditions. The labour rates assumed were discussed during meetings with Nalcor staff. A detailed listing of trades was provided with reasonable direct and indirect cost allowances. Labour rates were extended to account for payroll overheads, benefits, shift allowances, travel, and other costs.

Labour rates were developed for the full set of trades identified as necessary for the works. Indirect costs were derived by estimating the cost basis of the anticipated expenses. Indirect costs for accommodations, meals, site services, and travel were determined from the estimated construction schedule. Workers are assumed to work on a rotation basis with a reasonable estimate of travel costs included for home leave during each rotation.

Historical as built productivity rates for the main elements for the civil construction works were considered in the development of the estimate. Productivity rates were based on the experience of Nalcor estimators, norms obtained from SNC-Lavalin, and other cost estimating specialists. The approach used to estimate construction labour costs is considered to be reasonable.

5.5.3 Construction Materials

Construction materials such as fuel, reinforcing steel, cement, fly ash, etc. were determined using a combination of supplier quotations and local estimating expertise. Materials costs were determined to include the cost for shipping, handling, and storage at the project site.

The approach adopted by Nalcor focussed on the largest elements of the construction materials costs including fuel, cement, fly ash, and steel. Indices for each of these were developed for the cost

[132] Exhibit 31, Nalcor, “Technical Note: Lower Churchill Project Cost Estimate Progression, 1998 to 2011”, July 2011

estimate. The consumption of the materials was determined from quantity estimates for the permanent construction works and for the general construction works.

Estimates for material costs and escalation were obtained from vendor intelligence with consumption based on estimator norms. An allowance was included for contractor overhead and profit. Detailed benchmarking of the cost estimate was not possible within the available time. However, fuel costs were noted to be consistent with current market conditions although this item is highly variable. Steel fabrication costs are somewhat higher than anticipated from a similar project.

Based on the information available, the cost of construction materials used for the cost estimate appears to be reasonable.

5.5.4 Construction Equipment

The cost of construction equipment was obtained from supplier budget quotations and local estimating expertise.

Construction equipment was determined from an estimate of the major fleet composition to complete the works identified in the WBS within the time available in the Project Control Schedule.

Hourly equipment rates were derived from the purchase cost of equipment (trucks, excavators, bulldozers, cranes, etc.) with allowances made for depreciation, maintenance and operating costs, down time, and salvage value. Depreciation was assumed over a five year term in determining the operating costs. A salvage value of about 20% was included in the rate estimation. The actual value of salvage would depend on the condition and utilization of the construction fleet. The values adopted by Nalcor are believed appropriate for the purpose.

Construction equipment productivity was developed from industry fleet productivity norms and adjusted to local conditions by benchmarking with external construction advisors. The approach adopted for the cost estimate is reasonable.

5.5.5 Permanent Equipment Packages

The cost of permanent equipment was obtained from supplier's budget quotations for the main turbine-generator package and the principal electrical systems. The quotations were adjusted to account for escalation from the bid date and to correct for known changes in the market conditions.

The major permanent equipment is the turbine-generator package, which would be supplied by one of a small number of qualified manufacturers internationally. The cost of this equipment is related to international commodity pricing for steel, copper, fuel, and other indices. However, prices are subject to variation depending on the number of orders manufacturers have in hand for projects.

5.5.6 Owner's Management and Engineering

The cost for owner's management and engineering was derived for the anticipated project organization with costs built up from the anticipated salary rates, expenses, and other costs. The estimate has allowed for the cost of the engineering studies and design based on the value of contracts already awarded. The owner's management organization structure was developed and used as a base of the estimate by including salary and overhead costs for the anticipated management, engineering, and support staff positions.

Indirect costs were included for salary uplifts, travel to site, accommodations and allowances, vehicles, provision of offices, and other details. The cost of project permits is included.

Based on the information available, Nalcor's process for developing an estimate of costs for the owner's management and engineering is reasonable for an AACE Class 4 estimate.

5.5.7 Summary of Base Cost Estimate

The overall cost estimate was derived from the WBS, project control schedule and cost inputs using the Prism and Chief Estimator software packages. The use of this software has allowed Nalcor to apply a detailed and structured approach to the cost estimate that should allow for a reliable valuation of the overall cost of the Project.

Nalcor has prepared a very detailed estimate for the work. There is no reason to believe that the scope of work identified for the estimate is incomplete. The resulting cost estimate appears to be consistent with the nature of the works proposed for construction, local conditions, and construction market conditions.

5.5.8 Capital Cost Estimate and Risks

The overall capital cost of the Muskrat Falls project comprises the base cost estimate plus allowances for contingencies, cost escalation, and interest during construction. The following paragraphs provide comments on the methods adopted by Nalcor to establish estimate contingencies and an allowance for cost escalation during construction.

The estimate contingency makes provision for uncertainties, risks, and changes within the project scope. Nalcor has defined these as "tactical" risks that are within the project domain and, as such the cost is part of the capital cost for the Project. Tactical risks are assumed to be those elements that are within the control of the Owner's project management team. Tactical risks arise from uncertainties in the information available for the cost estimate. An example can be differences in the valuation of cost elements or variation in the estimate of work quantities for work carried out within the project scope.

Nalcor reported that contingencies were estimated through examination of the cost estimate to identify factors most likely to cause variation in the project costs. The potential change in these factors was then assessed through a combination of analytical tools and estimator's experience. Risk analysis using Monte Carlo simulation was adopted to evaluate the potential range in the cost estimate given the identified risk elements.

Cost escalation allowance makes provision for changes in price levels that are driven by economic conditions. Nalcor determined an escalation analysis from the Base Cost Estimate model by adjusting the value of the various input costs using published cost indices that were escalated through the construction period to provide input cost forecasts. When combined with the project control estimate, the escalation allowances illustrate the increase in project cost as part of the cash flow.

The approach adopted for the project cost contingencies and escalation is reasonable. Both elements are part of the capital cost estimate for the development, with the total number represented by the expected capital cost expenditure. Note however, that the project cost estimate (sum of Base Estimate, plus contingency, plus escalation allowance) does not include any provision for changes to elements such as the project scope, or unexpected events such as strikes, abnormal weather, etc. A financial contingency would normally be established to allow for such factors in creating the project budget.

MHI finds that the capital cost estimate provided by Nalcor is within the accuracy range of an AACE Class 4 estimate appropriate for DG2.

5.6 Muskrat Falls Project Cost Increases

After examination of the relevant documents, it was noted that the cost estimate for the Muskrat Falls development had increased by 104% between 1998 and 2010. This substantial increase was reviewed and it was determined that it can largely be explained by inflation and a change in scope. The change in scope is the addition of the 2 – 345 kV transmission lines from Muskrat Falls Generating Station to Churchill Falls Generating Station, associated switchyards, environmental costs, and other items such as insurance. While the cost increase cannot be fully explained by these factors, MHI considers the current cost estimate to be within the accuracy range of an AACE Class 4 estimate (+50%/-30%) which is representative of a feasibility level study.

5.7 Conclusions and Key Findings

The Muskrat Falls Generating Station feasibility studies, cost estimates, and schedule were examined by MHI's technical experts to determine whether they were completed using practices and procedures normally followed in the development of hydroelectric sites.

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

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

Based on the information available, the overall construction duration is believed to be reasonable. The project schedule indicates that the Muskrat Falls development can be completed within a total of about 62 months, assuming release for construction and commencement of contract awards in January of year one.[133]

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

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

- The proposed layout and design of the Muskrat Falls Generating Station appears to be well defined and consistent with good utility practices.
- The general arrangement of the permanent works is a reasonable proposal for the optimum development in terms of cost and construction duration.
- Based on the information provided, the design and construction of Muskrat Falls Generating Station is consistent with good engineering and construction practices, and should not pose any unusual risks for construction or operation of the facilities.
- The available studies have identified technical risks and appropriate risk mitigation strategies.
- The cost estimate for the Muskrat Falls development has increased by 104% between 1998 and 2010 which can largely be explained by inflation and a change in scope. The change in scope is the addition of the 2 – 345 kV transmission lines from Muskrat Falls Generating Station to Churchill Falls Generating Station, associated switchyards, environmental costs, and other items such as insurance. Despite the additional costs, MHI considers the cost estimate at DG2 to be within the accuracy range of an AACE Class 4 estimate (+50%/-30%) which is representative of a feasibility level study.

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

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6 HVdc Converter Stations and Electrodes

Report by: L. Recksiedler, P. Eng.

6.1 Introduction

The Labrador-Island Link HVdc system is configured as a ±320 kV 900 MW Line Commutated Converter HVdc bipolar transmission system with two sections of overhead transmission line, the Strait of Belle Isle marine crossing, shore line pond return electrodes, and converter stations at Muskrat Falls and Soldiers Pond. The total transmission line length is approximately 1100 km depending on final route selection.

The overall HVdc system configuration, as partially depicted in

Figure 9, is described in the "Overview of Decision Gate 2 Capital Cost and Schedule Estimates", Figure 2[134]. The Strait of Belle Isle (SOBI) cable marine crossing is comprised of 3 ±350 kV submarine cables that enter the Strait via horizontal directionally drilled (HDD) holes from both shores, and then laid on the sea floor with appropriate cable protection. The cable route is approximately 30 km long.

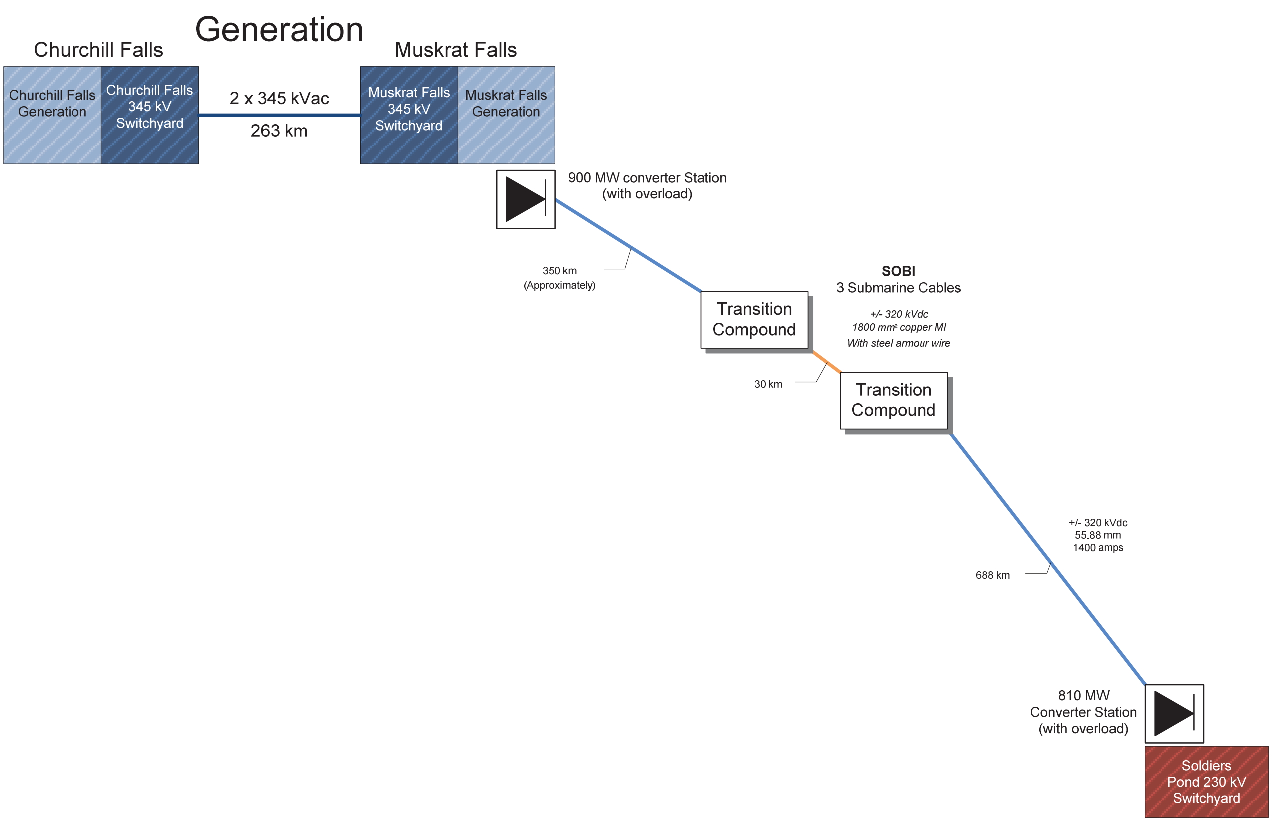

Figure 9: Labrador-Island Link HVdc System Configuration

[134] Exhibit CE-51 Rev.1 (Public), Nalcor, "Technical Note: Muskrat Falls Generation Facility and Labrador – Island Transmission Link Overview of Decision Gate 2 Capital Cost and Schedule Estimates", August 2011

6.2 Review Considerations

Most of the documentation available was for a 1600 MW 3-terminal HVdc system to Soldiers Pond and Salisbury, New Brunswick. With the decision at DG2 to advance the Infeed Option, little documentation on the new proposed configuration was available. This lack of information on the new project definition hampered MHI's review.

MHI examined available documents to assess the suitability of the specified technical design parameters to meet the objectives of the overall project, cost estimate, and schedule. This report includes a discussion on technical specifics, and provides a basic understanding of the technology and MHI's findings.

The Labrador-Island Link HVdc system is an integral part of the Infeed Option to supply the Island of Newfoundland with a reliable dedicated source of energy. This requires significant attention to the project definition and design requirements of the HVdc system to be designed and built by the manufacturer.

One of the primary requirements identified in the design progression is for the HVdc system to operate with an overload capability that would cover the loss of one pole, or one-half of the HVdc transmission capability.[135] Prior studies using a simplified energy balance model of the Island system showed that, with a dc capability per pole of 2.0 pu power transfer for 10 minutes followed by a continuous 1.5 pu of pole overload capability the risk of load shedding due to loss of a single pole would be reduced[136].

The Labrador-Island Link HVdc system is designed for an N-1 contingency (loss of any one element) and the analysis considers this, together with relevant industry standards.

Nalcor has noted, as their first assumption in section 6.3 of Exhibit 30 General Overview of Design Assumptions, that only proven technologies will be considered, unless it can be clearly demonstrated that emerging technologies can be as reliable and provide significant cost or schedule improvements.

Nalcor states that the designs will be consistent with:

- Good Utility Practices
- Life Cycle Costing
- Nalcor Health and Safety Policies
- Nalcor Environmental Policy and guiding principles
- Nalcor asset management philosophy
- Applicable Standards, Codes, Acts and Regulations

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[135] Exhibit 30, Nalcor, "Technical Note: Lower Churchill Project Design Progression, 1998 to 2011", July 2011
[136] Exhibit CE-31 Rev.1 (Public), Teshmont, "Gull Island to Soldiers Pond HVDC Interconnection – DC System Studies – Volume 1", December 1998

The Muskrat Falls Generating Station is rated at 824 MW (515 MW continuous rating) and produces an average of approximately 4.91 TWh annually.[137] Connected to the Muskrat Falls converter station switchyard would be two 263 km, 345 kV transmission lines to Churchill Falls where an additional 300 MW of recall is available for NLH use. Part of this recall is currently allocated for Labrador loads.[138]

Prior to DG2, considerable studies were conducted for the Gull Island development based on the concept of a three terminal 1,600 MW, HVdc system. After DG2, the HVdc system was redefined with Muskrat Falls Generating Station to be constructed first and a power transfer of 900 MW on a conventional LCC two terminal point to point HVdc transmission system.

The assessment of the Labrador-Island Link HVdc Converter Stations was based on information and documentation provided by Nalcor and meetings with Nalcor staff. The cost estimates were benchmarked against industry standards and costs and estimates related to other projects from MHI's experience.

6.3 Documents Reviewed

The following documents were reviewed:

6.3.1 Teshmont Consultants, 1998, Gull Island to Soldiers Pond HVdc Interconnection – Engineering Review and Update of Capital Cost Estimate[139]

The conclusion of Teshmont's engineering review is that, with current proven technology, transmission of 800 MW from the Gull Island generating plant to Soldiers Pond is feasible and will improve the reliability of the supply of electricity to customers on the Island of Newfoundland.

The Teshmont review of cost estimates indicates that the system could be built for a capital cost based on 1998 Canadian dollars of $1,428 million within an accuracy of ±10%.

A summary of changes stated in the Teshmont engineering review included:

- *"The valve groups will be designed for continuous and short time overload capability so that load shedding will not occur in the Newfoundland ac system for transient and permanent pole outages on the Interconnection.*
- *The dc converters will have a single valve group per pole rather than two groups per pole. This will reduce costs and provide a more reliable system as compared to systems considered in previous studies.*
- *The dc line will be constructed with an overhead ground wire. The overhead ground wire will greatly reduce the number of transient pole faults from lightning strikes.*

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[137] Exhibit CE-27 Rev.1 (Public), Nalcor, "Muskrat Falls Hydroelectric Development Summary of Studies on Firm and Average Energy Production", June 2011
[138] Response to RFI PUB-Nalcor-32
[139] Exhibit 18, Teshmont Consultants, "Gull Island to Soldiers Pond HVdc Interconnection – Engineering Review and Update of Capital Cost Estimate", June 1998

- *The submarine cable crossing of the Strait of Belle Isle will consist of three submarine cables, each rated for 1500 A. This rating allows continuous operation of up to 50% overload on each pole with a single cable. One cable is provided as a spare."*

6.3.2 Hatch 2008, Volumes 1 to 6 HVdc Integration Study

The Hatch 2008 Study is available in six volumes and is found in Exhibits: CE-03 (Public), CE-04 Rev.1 (Public) through CE-07 Rev.1 (Public), and CE-08 Revision 1 (Public). The Scope of work in this study included: power flow and short circuit analysis, comparison of the performance of conventional and Capacitor Commutated Converter (CCC) HVdc technologies, transient stability analysis, cursory evaluation of alternate HVdc configurations, and development of a multi-terminal HVdc model for future system studies.

The principal objectives of the HVdc System Integration Study were to:

- *"Demonstrate the feasibility of a multi-terminal HVdc link connecting Labrador, Newfoundland, and New Brunswick given the requirements of the Newfoundland system.*
- *Determine the system additions required for integrating the proposed three-terminal HVdc system into the Labrador and Newfoundland systems. Although basic consideration was given to integration into the New Brunswick system, the study concentrated on the Labrador and Newfoundland systems. A separate system impact study was to be performed by the New Brunswick system operator to assess the requirements in New Brunswick.*
- *Determine the limitations of the proposed HVdc system.*
- *Determine feasible mitigation steps to ensure that the integrated system performs in an acceptable manner.*
- *Ensure that the integrated system design minimizes the need for load shedding in Newfoundland."*[140]

Many of the issues observed are not necessarily due to the HVdc infeed but rather the lack of transmission linking the generation in the west to the load in the east. The study also recommended that a minimum ESCR of 2.5 for the inverter ac systems be maintained. The feasibility of the proposed multi-terminal HVdc system was demonstrated with good performance and a number of key ac system upgrades were identified to support the HVdc inverter connection[141].

It must be noted that these studies were not related to the Muskrat Falls and Labrador-Island Link HVdc projects that make up the Infeed Option.

6.3.3 Hatch 2008, Voltage and Conductor Optimization[142]

Two transmission scenarios were evaluated in the Hatch study to determine if there would be any impact on the selection of voltage and conductors. The two scenarios are as follows:

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[140] Exhibit CE-03 (Public), Hatch, "The Lower Churchill Project DC1020 - HVdc System Integration Study Volume 1 - Summary Report", May 2008
[141] Exhibit CE-03 (Public), Hatch, "The Lower Churchill Project DC1020 - HVdc System Integration Study Volume 1 - Summary Report", May 2008
[142] Exhibit CE-01 Rev.1 (Public), Hatch, "The Lower Churchill Project DC1010 - Voltage and Conductor Optimization ", April 2008

- Scenario 1: 800 MW transmission from Gull Island to Soldiers Pond
- Scenario 2: 1,600 MW transmission from Gull Island with 800 MW to Soldiers Pond and 800 MW to Salisbury, N.B.

A single conductor is recommended for ice buildup mitigation

- Scenario 1: ±400 kVdc with a single, 50.4 mm diameter conductor.
- Scenario 2: ±450 kVdc with a single, 58.0 mm diameter conductor.

The Hatch 2008 study determined that there was little difference in cost between the two scenarios.

6.3.4 Siemens 2010, HVDC PLUS Feasibility Study[143]

This confidential report, which discusses the option of transmitting power from the Lower Churchill Falls Project (LCP) with the new multilevel voltage source converter (VSC) technology, was reviewed by MHI.

6.3.5 ABB 2011, Lower Churchill Project, PSS/E Transient Stability Pre-study[144]

This confidential report which was related to the application of VSC technology was reviewed by MHI.

6.3.6 Nalcor's Lower Churchill Project Design Progression 1998 -2011[145]

The original configuration of the Labrador-Island HVdc Link was based on a bipole system proposed in 1998 with an 800 MW transmission system from Gull Island to Soldiers Pond having a pole overload capacity of 200% (800 MW) for 10-minutes and 150% (600 MW) continuous.

With the decision at DG2 in November 2010, the 1600 MW multi-terminal HVdc scheme, as studied in 2008, was replaced with a smaller point-to-point system from Muskrat Falls to Soldiers Pond (Infeed Option). It was determined that the HVdc link should be sized at 900 MW, based on the size of the Muskrat Falls development, obtaining up to 300 MW of recall from Churchill Falls and moving an estimated 4.9 TWh over the HVdc scheme. Analysis carried out in June and July of 2010 confirmed that a 900 MW HVdc link between Labrador and the Island would require a minimum operating voltage of ±320 kV to ensure that transmission losses for the proposed HVdc system would be in the order of 10% at peak.

While this is a bipole HVdc system, it still requires a return path to operate under normal conditions and provide a return path during infrequent periods of mono-polar operation. Earlier studies, in particular a 1998 report by Teshmont, assumed that a sea electrode would be installed in Lake Melville for the Labrador converter station and in Conception Bay South for the Soldiers Pond converter station.

[143] Exhibit CE-62, Siemens, "HVDC PLUS Feasibility Study" June 2010
[144] Exhibit CE-63, ABB, "Nalcor Energy - Lower Churchill Project, PSS/E Transient Stability Pre-study", July 2011
[145] Exhibit 30, Nalcor, "Technical Note: Lower Churchill Project Design Progression 1998 to 2011", July 2009

In 2007/2008 Nalcor initiated an electrode review by Statnett of Norway[146]. The resulting report recommended sea electrodes for both converter stations and did not consider other types of electrodes, such as land, shoreline or shoreline pond electrodes.

Accordingly, in 2009, Nalcor assembled a panel of five experts to complete a thorough electrode review. The panel, working closely with Hatch, issued the report on electrode types and locations[147] in 2010. This report recommended the use of shoreline pond electrodes for the Soldiers Pond converter station and recommended further work to confirm type and location of electrodes for the Labrador converter station. This further work was completed and culminated in the report "Electrode Review, Confirmation of Type and Site Selection"[148]. This report recommended shoreline pond electrodes for the Labrador converter station to be constructed on the Labrador shore of the Strait of Belle Isle and confirmed shoreline pond electrodes for the Soldiers Pond converter station to be constructed on the east shore of Conception Bay.

6.3.7 Hatch 2010, HVdc Sensitivity Studies Final Summary Report[149]

The purpose of the Hatch 2010 study was to explore selected topics identified as additional work subsequent to the completion of the HVdc System Integration Study identified in section 6.3.2. Stated goals of the study included:

- *"HVdc Sensitivity Studies - Sensitivity studies to investigate whether system reconfiguration, relaxation of the planning criteria, special protection schemes, or some combination thereof would enable the removal of the Pipers Hole synchronous condensers, while facilitating acceptable system performance.*

- *PSSE Model Modification - Modification of the multi-terminal PSSE model, developed as part of the original HVdc System Integration Study, reflects a potential alternate cable route through Cabot Strait and overhead line in the Maritime Provinces.*

- *VSC Risk Assessment - A high-level risk assessment of VSC technology for both a multi-terminal hybrid HVdc scheme and a Labrador to Island point-to-point HVdc scheme.*

- *Ac/dc Line Proximity Issues - A high-level identification of potential interaction issues resulting from the location of ac and dc lines in close proximity.*

- *Bipole Block Impacts - Investigation of the impact of a bipole block on the Island ac system."*

The study stated that "the main issue in the Island system with the HVdc infeed is the lack of inertia and resulting frequency decay due to faults which cause the HVdc infeed to fail commutation; the nearer the fault location to Bay d'Espoir generating station, the more power is temporarily lost and the more severe the system frequency decay." The study concluded that the power system performance

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[146] Exhibit CE-09 Rev.1 (Public), Hatch, "Lower Churchill Project DC110 - Electrode Review Gull Island and Soldiers Pond", March 2008
[147] Exhibit CE-11 (Public), Hatch, "Lower Churchill Project DC1250 - Electrode Review Types and Locations", March 2008
[148] Exhibit CE-12 Rev.1 (Public), Hatch, "DC1500 - Electrode Review, Confirmation of Type and Location Final Report", December 2010
[149] Exhibit CE-10 Rev.1 (Public), Hatch, "Lower Churchill Project – DC1210 – HVdc Sensitivity Studies", July 2010

of the 800 MW bipolar case was worse than the 600 MW monopolar case. A significant improvement in system performance was obtained with the addition of 2 – 300 MVAr high inertia synchronous condensers. A third synchronous condenser was suggested for reliability.

The report states that "without the installation of synchronous condensers at Pipers Hole, the Sunnyside bus requires dynamic voltage support in the form of a Static Var Compensator (SVC)". Either a SVC at Sunnyside or a new 230 kV circuit between Bay d'Espoir and Western Avalon will provide an acceptable system performance for all contingencies except the three-phase fault at Bay d'Espoir.

The Hatch 2010 study stated that:

> *"with the Soldiers Pond infeed modeling VSC technology, all simulations were stable and the post-fault voltages were within acceptable limits for all of the contingencies described in Table 4.1 without any synchronous condensers operating at Soldiers Pond and without any new synchronous condensers elsewhere in the Island system (with the exception of the Holyrood machines running as synchronous condensers)."*

With regards to the ac/dc proximity issues, the study states that:

> *"Based on the available literature and current industry experience, the use of a hybrid line with the HVdc and ac conductors on a common tower may not be suitable for the proposed line route, mainly due to the high level of interaction between the ac and dc lines and the potential for HVdc to ac conductor faults. In situations where common towers are used for short distances, the risk of an HVdc to ac conductor fault may be acceptable."*

The use of HVdc and ac lines in close proximity on separate towers may be suitable if an acceptable separation can be maintained. The suitability of this option would require detailed studies in order to determine potential candidate line configurations, and any required mitigation measures to ensure acceptable performance of the integrated HVdc and ac systems. Current industry experience can be used as a starting point for determining a potential minimum separation distance between the HVdc and ac lines. Once this is identified the suitability of the existing right of way can be better assessed.

The use of a direct buried ac cable, with the HVdc on towers on the same right of way may be suitable; however, studies would be required to determine the potential effects of HVdc ground faults on the buried ac cable.

6.3.8 NLH, 2010, Preliminary Transmission System Analysis, Muskrat Falls to Churchill Falls Transmission Voltage[150]

The report states the following in the executive summary:

> *"Preliminary analysis indicates that at least four single conductor per circuit 230 kV transmission lines would be required between Muskrat Falls an Churchill Falls for stable operation of the power system during expected contingencies. Moving to a two conductor*

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[150] Exhibit 59, NLH, "Preliminary Transmission System Analysis, Muskrat Falls to Churchill Falls Transmission Voltage", November 2010

bundle at 230 kV results in a minimum of three 230 kV transmission lines between Muskrat Falls and Churchill Falls to provide reasonable assurances of stable system operation.

Alternatively, moving to the 362 kV transmission class indicated that a minimum of two 315 kV or two 345 kV transmission lines can be expected to provide reasonable system performance. There are advantages and disadvantages of each the 315 kV and 345 kV operating voltage.

For project costing, it is recommended that two 345 kV transmission lines, with a two conductor bundle of 795 MCM 26/7 ACSR "Drake" per phase be assumed. In addition, to ensure acceptable voltage control on line open end conditions, four 345 kV, 45 MVAR shunt reactors (one per each transmission line end) be included.

Detailed stability studies in final design will be required to determine the technical applicability of moving to a 315 kV operating voltage level.

Further analysis is required to determine if application of on-load tap changers, on the 735/345 kV autotransformers, can be sized to provide the necessary voltage control and eliminate the need for independent shunt reactors. This will ultimately be a decision of economics and operability in final project design."

6.4 HVdc Technology Overview

HVdc transmission is a proven, mature technology that has been in commercial service with many utilities since the 1950's, with numerous projects implemented worldwide. The first viable HVdc transmission technology is termed Line Commutated Converter (LCC) technology, which is a directional current flow dc configuration. LCC HVdc uses a power electronic thyristor switching device as the main engine of the LCC system to switch the current on at the correct instant thereby converting ac into dc at one end of the system (Muskrat Falls), and dc current back into ac at the receiving end (Soldiers Pond).

During the1990's a second type of HVdc technology became commercially viable based on the voltage sourced converter (VSC) concept. The switching device in VSC HVdc system is an insulated gate bipolar transistor which can be switched numerous times in each fundamental frequency time period. The amount of power transferred is controlled by switching the voltage applied to the dc side of the circuit. There are fundamental differences between LCC and VSC transmission systems. One significant difference is that VSC technology can control both real and reactive power injected into the system at the inverter end. Unlike LCC implementations, VSC technology does not require a minimum Equivalent Short Circuit Ratio (ESCR) and can be used in a black start situation. Both LCC and VSC technologies are commercially viable and are being specified in projects where power transfer ratings are equivalent (i.e. ±500 kV 1000 MW systems).

HVdc transmission systems are used for the following reasons:

- Economics for interconnecting ac systems over long distances. The overall capital construction costs and operating costs are lower for HVdc transmission when compared to ac systems covering the same long distance. The additional costs of building HVdc converter stations make dc systems economical only when compared to a long-distance ac transmission application.

- HVdc transmission lines use two conductors instead of three for ac systems, which result in smaller towers for the amount of power transfer.
- More power can be transmitted using dc than ac in the same sized transmission corridor.

- HVdc can asynchronously connect systems with different frequencies; this is not possible with ac transmission.
- HVdc transmission systems allow power flow on the dc transmission path to be precisely controlled; this degree or range of control is not possible with ac systems
- Fast, flexible dc controls can be used to support operations of ac systems either with reactive support or stabilization during disturbances.

There are a number of configurations used for HVdc applications throughout the world with both LCC and VSC transmission technologies. The two main HVdc LCC configurations in use are monopole and bipole configurations for point to point HVdc transmission. The monopole and bipole configuration can include a neutral conductor, an earth return current path or sea return current path (which includes shore electrodes).

6.4.1 Configurations of HVdc Technology

The following configurations are applicable to both the VSC technology as well as the LCC technology. The main difference is that the valves themselves are configured with new switching devices resulting in different operating characteristics.

Regarding monopole HVdc, one dc pole's polarity will operate with a positive or negative dc voltage. The return path can be a conductor, operating at earth (zero) volts or the earth itself. The connection to the earth can be an earth, shoreline or sea (water) electrodes. Figure 10 shows a monopole earth return system where another variant would be a solid return conductor with one end grounded.

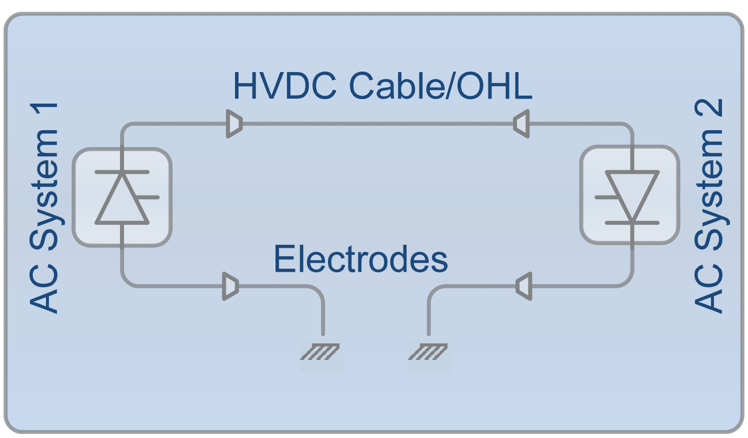

Figure 10: Monopole Configuration with Electrode Return (Source: Alstom)

Bipolar HVdc systems consist of both a positive and a negative pole where the dc current will travel via the positive pole and return via the negative pole. The connection point between the positive and negative poles is grounded to the earth. In the event that one pole faults, the other un-faulted pole can remain in service, using either the electrodes to transfer the current or use the neutral conductor as the return path.

The advantage of a bipolar system is that in normal operation virtually no earth or neutral current is present. When one pole is out of service due to a fault or for scheduled maintenance, 50% of the transferable capability is still available and with overload capability this can even be higher. See Figure 11. The red line shows the current path when one pole is out of service.

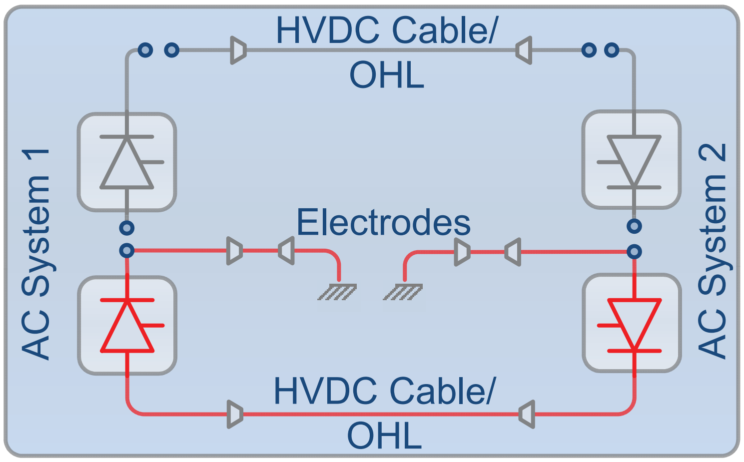

Figure 11: Bipole in Monopole Operation (Source: Alstom)

6.5 Choice of HVdc Technology

A new HVdc valve technology exists with the recent introduction of the multi-module voltage source converter (VSC) valve. VSC systems of this size and length have not been built or operated anywhere in the world to date.

According to documents supplied by Nalcor, a risk assessment indicated that the VSC HVdc technology would not be considered at this time as there was no clear economic or technical advantage thus retiring this risk.[151] Voltage Source Converters have a slow clearing time for a dc fault, do not require synchronous condensers to support the dc to ac conversion process, and have acceptable system performance when the ESCR is less than 2.0 pu. ESCR is an important design parameter as it relates to both voltage and frequency control on the island. Nalcor has stated:

> *"Given expected continued advancement of VSC technology, Nalcor has not ruled out VSC as a technology option in the future.*

[151] Exhibit CE-52 Rev.1 (Public), Nalcor, "Technical Note – Strategic Risk Analysis and Mitigation", August 2011

At DG2, however, with no technical or economic benefits for VSC technology, Nalcor elected to include proven LCC technology in the DG2 Basis of Design and to avoid the VSC risk premium as identified in Confidential Exhibit CE-52."[152]

There are many technical considerations and requirements, and for VSC technology to be considered, it must provide similar or superior performance and a lower cost.

New technology recently announced by ABB that would improve the performance of a VSC HVdc link is the development of an HVdc breaker. The ABB HVdc breaker claims to operate within 2 milliseconds and would solve the slow dc fault clearing time which is an issue for VSC valves.[153]

6.6 Muskrat Falls Converter Station

The Muskrat Falls converter station is planned as a LCC type of HVdc system. This is a proven technology with a long history of successful application to numerous projects. The converter station design is a 900 MW ±320 kV bipolar system.[154] This configuration can operate either mono-polar or use only one pole with the earth return to transmit half of the power except as noted below with respect to overload capability.

Each pole will normally operate at a continuous rating of 450 MW. The overload capability for each pole specified in the design progression is for 200% or 900 MW for ten minutes, and 150% or 675 MW continuous rating. The Infeed Option requires this overload capability to mitigate the loss of a pole contingency. The Infeed Option as defined in the design progression has no other interconnections, and thus cannot rely on power from alternative sources. The most likely event is the loss of a pole, which corresponds to a loss of 450 MW. Without the overload capability, the loss of 450 MW could not be covered by the Soldiers Pond Converter Station. This loss of generation would lead to potential load shedding, or possible system collapse leading to a black-out. The 10 minute overload rating with appropriate controls helps with system stability issues. The 150% overload rating results in a single contingency of 225 MW which is the difference between the 200% rating and the 150% rating of the two poles. This continuous overload capability translates into increased costs of the converter station equipment and, depending on the design, premature aging of the equipment may occur with extended use. A continuous overload rating specifies that the equipment has essentially been designed for a total of 1,350 MW of power transfer for the HVdc system.

A converter station typically has both an ac and a dc switchyard. The ac switchyard for Muskrat Falls is at the 345 kV level with two lines to Churchill Falls. There would be four ac filter banks to adsorb the ac side harmonics and provide some of the reactive power requirements of the HVdc converters. There are only two station service transformers planned to provide auxiliary power at the converter stations; however, a third may be required for converter station reliability. [155] Station service or a similar feed is

[152] Response to RFI MHI-Nalcor-67 Rev.1
[153] Jürgen Häfner (ABB), Björn Jacobson (ABB), "Proactive Hybrid HVdc Breakers – A key innovation for reliable HVdc grids", Cigré International Symposium, Bologna, September 2011
[154] Exhibit 30, Nalcor, "Technical Note: Lower Churchill Project Design Progression 1999 to 2011", July 2011
[155] Exhibit 30, Nalcor, "Technical Note: Lower Churchill Project Design Progression 1999 to 2011", page 24 Proposed Single Line Diagram, July 2011

required to provide redundancy so full power output from the converter station can be maintained when one station service transformer is out for maintenance or has failed.

The requested single line diagram of the HVdc switchyard and converter station equipment was not available at this time. The single line diagram provided by Nalcor in response to RFI MHI-Nalcor-64 was for the ac switchyard.

Based on MHI's experience, most of the HVdc converter equipment has a design life of 35 to 40 years whereas the life of the project is 50 years. The HVdc controls and protection equipment have a life of only about 15 to 20 years and require replacement at a cost of about $ 12 million. Converter transformers have an expected lifespan of 35 years, and typically cost approximately $7 to 9 million. Based on the preliminary design information, there would be seven transformers in total, including a spare at each converter station. These costs are typical and derived from review of tender documents on other projects.

There were no specific performance requirements defined for the converter station available for MHI's review. MHI understands that a functional specification is being prepared by the EPCM contractor to be issued to HVdc suppliers as part of the detailed design. MHI is unable to comment on the adequacy of performance requirements and their conformance with current industry standards.

6.7 Soldiers Pond Converter Station

The Soldiers Pond converter station is similar in design to that of the Muskrat Falls converter station. Each pole will be rated at 450 MW with similar overload capabilities.

A unique feature of the Soldiers Pond converter station is that the ac switchyard contains three 300 MVAr synchronous condensers (Exhibit 30), two of which are required to keep the ESCR above 2.5 per unit to minimize the number and risk of commutation failures. Units which have a high inertial constant of 7.2 s are preferred over conventional machines with a rating of 2.5 s or lower. The synchronous condensers also provide continuously variable reactive power to aid in the dc to ac conversion process and control overvoltages. The synchronous condensers MVAr requirement can be adjusted to follow the daily load cycle requirement for reactive power and thus can minimize the switching operations on the ac filters. The synchronous condensers with a high inertial constant of 7.2 are very expensive devices and require extensive maintenance.

The performance of a LCC HVdc system becomes unacceptable below a 2.5 pu ESCR. There is the potential for numerous commutation failures from nearby electrical faults which may cause outages and equipment failures.

The inertial constant of 7.2 s for the synchronous condensers is required to stabilize the performance of the ac transmission system during disturbances. The added electrical inertia allows the HVdc system to ride through a system fault which could otherwise cause the HVdc system to block, slows frequency decay, and thus reduces the potential need for load shedding.

Again, no detailed information on the HVdc switchyard was made available for MHI's review other than the single line diagram for the Soldiers Pond ac switchyard.

6.8 AC System Upgrades Required for Labrador-Island Link HVdc System

AC system upgrades required for the HVdc system will include the conversion of two existing Holyrood Units # 1 and # 2 to synchronous condenser operation. Holyrood Unit #3 was previously converted to synchronous condenser operation. The replacement of a number of high voltage breakers is required because of the higher short circuit level generated by the additional synchronous condensers. The addition of two 300 MVAr synchronous condensers at the Soldiers Pond Converter Station is required to raise the ESCR above 2.5 pu. A third 300 MVAr synchronous condenser is required for reliability.

6.9 Electrodes

The electrode line is a distribution type line connecting the Muskrat Falls Converter Station to the electrode site location. The electrode provides a ground return path for unbalanced currents during bipolar operation and for the line current during monopolar operation.

The electrode line has been designed with wood pole structures for some 310 km from Muskrat Falls to the SOBI. Nalcor is considering the possibility of placing the electrode line conductors on the main HVdc transmission tower, which could eliminate the cost of the wood pole line. The placing of the electrode line conductors on the main HVdc transmission tower is feasible and has been implemented for shorter distances on other operating systems such as the Cahora Bassa Songo Converter Station.

The original studies done by Teshmont and Statnett had recommended sea electrodes. Nalcor was concerned that other types of electrodes were not considered in these studies. A sea electrode does have issues with chlorine production, compass navigation, and fish habitat concerns. As a result, the electrode will now be a shore line electrode which was recommended by a panel of five experts which would be easier and less expensive to install and maintain.[156,157] The electrodes are rated for a 40 year life span while the life of the project is 50 years, indicating a gap. There is also the possibility of running continuously for one year in the event that one undersea cable plus a spare cable is not available for any reason.

There is a second electrode line connecting the Soldiers Pond converter station to the electrode site location. The electrode line will have a 50 year reliability level return period. The electrode line from Solders Pond is a wood pole structure some 10 km in length to Dowden's Point on the east side of Conception Bay.

[156] Exhibit CE-11 (Public), Hatch, "The Lower Churchill Project DC1250 – Electrode Review, Types and Locations", March 2010
[157] Exhibit CE-12 Rev.1 (Public), Hatch, "DC1500 Electrode Review, Confirmation of Type and Site Selection", December 2010

6.10 Cost Estimate Analysis

MHI reviewed the cost estimates used by Nalcor for the converter stations, electrodes and synchronous condensers using industry accepted benchmarks and information from similar projects.

The two converter stations are planned to include equipment with 150% continuous overload capacity. The total cost estimate for the HVdc converter stations and electrodes based on an AACE Class 4 estimate are reasonable for DG2 purposes. The costs for the synchronous condensers are low but are still within the range of an AACE Class 4 estimate. For the purposes of developing a cost estimate comparison, MHI used data from similar prior projects.

6.11 Risk Review

There does not appear to be any risk analysis done for the HVdc converter stations or the operational aspects of the Labrador-Island Link HVdc system. Converter station outages could be lengthy and could be very costly to repair particularly if lost revenues are considered. MHI recommends that this be completed prior to the development of the HVdc converter station specification so any additional requirements can be included.

6.12 Conclusions and Key Findings

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

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

Key findings from the review of the HVdc converter stations, electrode lines, and associated switchyards are as follows:

- MHI found that the HVdc converter station system design parameters available for review are reasonable for the intended application. The intended application is to transmit 900 MW of firm power over 1100 km of transmission line and inject this power into the island's electrical system at Soldiers Pond with appropriate voltage and frequency control.

- The Labrador-Island Link design progression has specified LCC (line commutated converters) HVdc technology, which is mature and robust for the application.[158] However, the response to RFI MHI-Nalcor-67 has indicated that VSC (voltage sourced converter) options will be considered if there are technical and financial advantages to do so. It is important to note that VSC systems of the size and length of the Labrador-Island Link HVdc system have not yet been built and operated anywhere in the world as of the issue date of this report.
- The estimate for the HVdc converter stations and electrodes was reviewed by MHI and found to be within the range of an AACE Class 4 estimate. The cost estimates for the synchronous condensers are low but are still within the range of an AACE Class 4 estimate.

[158] Exhibit 30, Nalcor, "Technical Note: Lower Churchill Project Design Progression 1999 to 2011", July 2011

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7 HVdc Transmission Lines

Report by: L. Chaput, P. Eng.

7.1 Introduction

The ±320 kV HVdc bipolar transmission line is approximately 1100 km long from the Muskrat Falls Converter Station to Soldiers Pond Converter Station. It is comprised of an overhead section from the Muskrat Falls Converter Station to the Strait of Belle Isle (SOBI), cable transition compounds on either side of the SOBI, an undersea cable marine crossing, and an overhead transmission line from the SOBI to Solders Pond as presented in Figure 12.

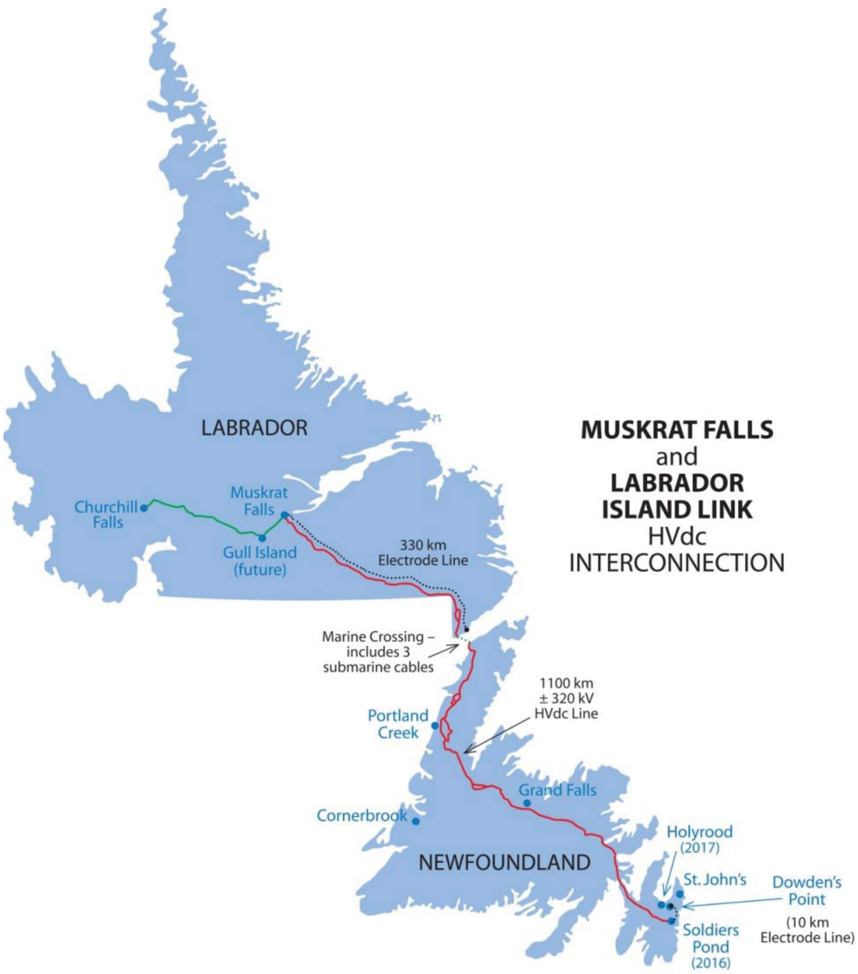

Figure 12: Muskrat Falls and Labrador-Island Link HVdc Interconnection (locations are approximate)

Prior to DG2 the HVdc transmission line was proposed from the Gull Island site at 1,600 MW for voltages of ±400 kV, ±450 kV or ±500 kV.[159] Following DG2 and the decision to proceed with the

[159] Exhibit CE-01 Rev.1 (Public), Hatch, "The Lower Churchill Project DC1010 Voltage and Conductor Optimization", April 2008

Muskrat Falls development the capacity of the line was reduced to 900 MW and was optimized for a voltage of ±320 kV. An analysis conducted confirmed that the minimum operating voltage of ±320 kV was possible to ensure that the transmission losses for the proposed HVdc link would be approximately 10%[160]. The transmission line conductor was selected to be a single wire design to minimize the formation of ice on the conductor.

7.2 Transmission Line Design Review

As indicated in Nalcor's response to RFI MHI-Nalcor-71, "The design details requested are not available as these are the subject of detailed design efforts by SNC Lavalin and will not be completed before 2012." MHI cannot provide comment on the overall tower design as none of the tower loading conditions were provided (i.e. construction loads, maintenance loads, torsional loads, broken conductor scenarios, etc.). As no proposed plan and profiles were unavailable, MHI cannot comment on the route selection or transmission line risk analysis.

7.3 Reliability Based Transmission Line Design

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

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

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

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

Nalcor's Exhibits 106 and 97 outline its reasoning for choosing its reliability level for new 230kV transmission lines and loading criteria for its Labrador-Island Link HVdc transmission line. Exhibit 97 "Review of Existing Meteorological Studies Conducted on The Labrador – Island Transmission Link,

[160] Response to RFI MH-Nalcor-62

September 2011" outlines the chosen ice and wind loads for the ±320kV HVdc transmission line[161]. Exhibit 106 describes a process of using reliability based design such as in CAN/CSA-C22.3 No. 60826:06.

Exhibit 106 describes the adoption of the IEC 60826:2003 with Canadian deviations as the National Standard of Canada and describes the process followed by Nalcor in its decision to use reliability based design as outlined in "Design Criteria of Overhead Transmission Lines" CEI/IEC 60826:2003 with Canadian deviations in CAN/CSA-C22.3 No. 60826:06. However, this Exhibit does not reference Section - 5 of CAN/CSA-C22.3 that outlines the recommended reliability based design methodology for designing transmission line components. A quick synopsis of the standard methodology is found below: Direct excerpts from IEC 60826 are shown in italics.

5.1 Methodology

a) Collect preliminary line design data and available climatic data.

Nalcor appears to have significant data collected[162,163].

MHI's review of material provided in response to RFI MHI-Nalcor-71, particularly the document "Review of Existing Meteorological Studies Conducted on the Labrador-Island Transmission Link" – Exhibit 97 states the design ice and wind loads for the different regions along the line are based on extensive research of the area.

Exhibit 97, Appendix A, "Ice Load Region Maps" outlines 11 line sections that have been categorized into three different ice loading zones (Average Climatic Region – 50 mm maximum ice load, Eastern Region – 75 mm maximum ice load, and Alpine Region – ice load yet to be determined). Regions that have been categorized as "Average Sections" contain six line segments in central and northern Newfoundland and Labrador. In this Region, the maximum ice load is 50 mm of radial glazed ice which does not conform to the 50-year return period minimum ice load of 60 mm outlined in Exhibit 106. It is unclear what the final design loads are for the Labrador-Island Link HVdc transmission line.

There is one line segment named the "Eastern Region" and four regions classified as "Alpine Region". Alpine regions are subject to heavy rime and glazed icing due to their elevation and topographical features of the area. It is expected that the design ice load values in the Alpine sections would be significantly larger than the rest of the regions. Also due to the difficulties in access, repair times may be long.

[161] Exhibit 97, Nalcor, "Review of Existing Meteorological Studies Conducted on the Labrador – Island Transmission Link," September 2011
[162] Exhibit 91, Landsvirkun Power, "HVDC Labrador – Island Transmission Link Review of in-cloud icing on the Long Range Mountain Ridge", May 2009
[163] Exhibit 106, Nalcor, "Technical Note: Labrador – Island HVdc Link and Island Interconnected System Reliability", October 2011

b1) Select the reliability level in terms of return period of limit loads.

Nalcor has begun this process based on its own historical data, Exhibit 106 states a 1:50 year return period is sufficient for the ±320 kV HVdc link.

b2) Select the security requirements (failure containment)

There is no information regarding the security containment of the line i.e., cascade failure prevention structures have not been noted in any of the Nalcor documents issued to date.

b3) List safety requirements imposed by the mandatory regulations and construction and maintenance loads.

No further transmission line design information was supplied by Nalcor.

Reliability based design is an appropriate method for the Infeed Option transmission line since there has been extensive meteorological analysis conducted as outlined in Exhibit 91. To support the design process, historical strength data for existing transmission lines are available from the work completed as part of the transmission line upgrade on the Avalon Peninsula.

It should be noted that the excerpts from CAN/CSA-C22.3 No. 60826:06 contained in Exhibit 106 are not complete and specific paragraphs were omitted. Most notably the last paragraph of Section 4.1 on page 27 which states:

> *"This standard also provides minimum safety requirements to protect people from injury as well as to ensure an acceptable level of service continuity (safe and economical design)."*

Safety and reliability considerations need to include both public and operational staff with regards to service continuity, line constructability and maintenance. The proposed Labrador-Island Link HVdc transmission line will cross through both urban and remote regions. Hydro Quebec discovered during the 1998 ice storm, where it lost over 600 km of transmission line, that the danger to the public, operational staff and time and expense to recover from an incident can significantly be reduced by designing to an increased reliability level.

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

> *"A.1.2.5 Selection of Reliability Levels*
>
> *Transmission lines are typically designed for different reliability levels (or classes) depending on local conditions, requirements and the line duties within a supply network.*

Designers can choose their reliability levels either by calibration with existing lines that have had a long history of satisfactory performance or by optimization methods found in technical literature.

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

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

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

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

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

Considering the directions given in the IEC Standard, the voltage level of the Labrador-Island Link HVdc transmission line, the importance of this HVdc transmission line, and the local historical data gathered by Nalcor during the investigation of the Avalon Peninsula upgrade project, at a minimum the ±320 kV HVdc line should be designed to a return period of 150 years. A 500-year return period for the transmission line design should be used for the Island power system without an alternate supply.

It should be noted that Manitoba Hydro is proposing the design of its new Bipole III HVdc transmission line with a 1:150 year return period.[164]

Exhibit 106 refers to the adoption of a 1:50 year return period for new 230 kV transmission line design and provides discussion that a 50-year return period is justifiable for the ±320 kV HVdc line. The response to RFI PUB-Nalcor-13 also documents the 1:50 year return period as suitable for the Labrador-Island Link HVdc transmission line when considered together with an alternate Maritime link.

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[164] Manitoba Hydro, "Environmental Impact Statement (EIS) for the Bipole III Transmission Project", December 2011, Section 3.4.1, http://www.hydro.mb.ca/projects/bipoleIII/eis.shtml

An investigation of failed 230 kV lines on the Avalon Peninsula "following the 1994 ice storm revealed that the original design ice loads of 25 mm to 38 mm have a return period of 1:10 years".[165] The investigation further outlines Nalcor's ice loading for the 50-year return period has a range between 60 mm and 75 mm of radial ice depending on the geographical location of the line. As suggested by the CSA Standard, there is a requirement to design to a 150 or 500 year return period which would put the minimum ice loadings at 69 mm or 78 mm of radial ice. Nalcor argues that since the existing 230 kV ac system is designed to a lesser reliability level, there is no justification to increase the reliability level of the HVdc link as the ac transmission system would fail for an event greater than 1 in 50 years. This argument is contrary to best practices carried out by utilities in Canada for transmission line design, and does not reflect current industry practices which follow IEC 60826:2003. Also, the ice storm could be isolated to an area where only the HVdc line is present. The 230 kV transmission system would be completely intact while the HVdc line is out of service. IEC 60826:2003, does state that "In some cases, individual utility's requirements can dictate other reliability levels depending on the proper optimizations between initial cost of the line and future cost of damage, as well as on uncertainties related to input design parameters." No optimization plan in accordance with the IEC 60826 standard has been provided or made available to justify the reduced reliability level.

7.4 Cost Estimate Evaluation

MHI has reviewed the cost estimate for the HVdc overland transmission line supplied in the confidential exhibit "Overview of Decision Gate 2 Capital Costs." [166] The DG2 capital cost estimate falls inside the typical range of capital construction estimates for this type and length of transmission line. Nalcor's estimate appears to be at the low end of the range.

Nalcor has estimated that the additional cost to building the transmission line to a 1:150 year return period is $150 million[167]. MHI also confirms that the estimated additional costs for moving from a 1:50 year return period to a 1:150 year return period would be in the order of $100 to $150 million.

7.5 Conclusions and Key Findings

Reliability based design is an appropriate method for the Infeed Option transmission line since there has been extensive meteorological analysis conducted.[168] To support the design process, historical strength data for existing transmission lines were available from the work completed as part of the transmission line upgrade on the Avalon Peninsula.

Considering the directions given in the IEC Standard, the voltage level of the Labrador-Island Link HVdc transmission line, the importance of this HVdc transmission line, and the local historical data

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[165] Exhibit 106, Nalcor, "Technical Note: Labrador – Island HVdc Link and Island Interconnected System Reliability", October 2011, pg. 10

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

[167] Response to RFI PUB-Nalcor-15

[168] Exhibit 106, Nalcor, "Technical Note: Labrador-Island HVdc link and Island Interconnected System Reliability," October 2011

gathered by Nalcor, at a minimum the ±320 kV HVdc line should be designed to a return period of 1:150-year when an alternate supply is available.

Key findings from the HVdc transmission line review are as follows:

- Nalcor has selected a 1:50-year reliability return period (basis for design loading criteria) for the HVdc transmission line, which is inconsistent with the recommended 1:500-year reliability return period outlined in the International Standard CEI/IEC 60826:2003 with Canadian deviations in CSA Standard CAN/CSA-C22.3 No. 60826:06, for this class of transmission line without an alternate supply. In the case where an alternate supply is available, the 1:150-year reliability return period is acceptable. In this latter scenario, Nalcor should also give consideration to an even higher reliability return period in the remote alpine regions[169]. MHI considers this a major issue and strongly recommends that Nalcor adhere to these criteria for the HVdc transmission line design. The additional cost to build the line to a 1:150 year return period is approximately $150 million.[170]

- The capital cost estimate of the transmission line at DG2 is reasonable, but at the low end of the range, for this type of construction utilizing industry benchmark costs as a comparison. A design based on a 150-year return period could be accommodated within the variability of an AACE Class 4 estimate at this stage of development for the entire Labrador-Island Link HVdc project.

[169] Exhibit 97, Nalcor, "Review of Existing Meteorological Studies Conducted on the Labrador-Island Transmission Link", September 2011 - Page 8. Alpine regions are defined as Southeastern portion of Labrador, two areas in the Long Range Mountains, and one small section in central Newfoundland.
[170] Response to RFI PUB-Nalcor-15

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8 Strait of Belle Isle Marine Cable Crossing

Report by: E. Colombo, Ing. (CESI)
A. Snyder, P. Eng.
P. Wilson, P. Eng.

8.1 Introduction

The Strait of Belle Isle (SOBI) cable crossing involves the placement of three submarine cables, 36 km long in a circuitous route across the Strait of Belle Isle. The cables will be installed from the landfalls on either shore beneath the sea bed using Horizontal Directional Drilling (HDD) techniques. The cables will then lay on the bottom in deep water, separated by a specified distance, and be protected by rock berms placed over top to provide the required cable protection. Given the directions provided by the numerous consultants' reports, a conceptual design has been developed to provide a technically feasible solution.

The cables will have a shore approach on the Labrador coast with a landing site in the area of L'Anse Amour beach in Forteau Bay and on the Newfoundland side in the area of Mistaken Cove.

The cable corridor in which the conceptual cable route is defined is shown in Table 21. The estimated shore-to-shore distance between Labrador and Newfoundland is approximately 18 km but the route chosen is a deep trough and has approximately 32 km of cable on the sea floor. The route is depicted within a 500 m wide corridor with a 1500 m diameter circular sea floor piercing target zone for the HDD.

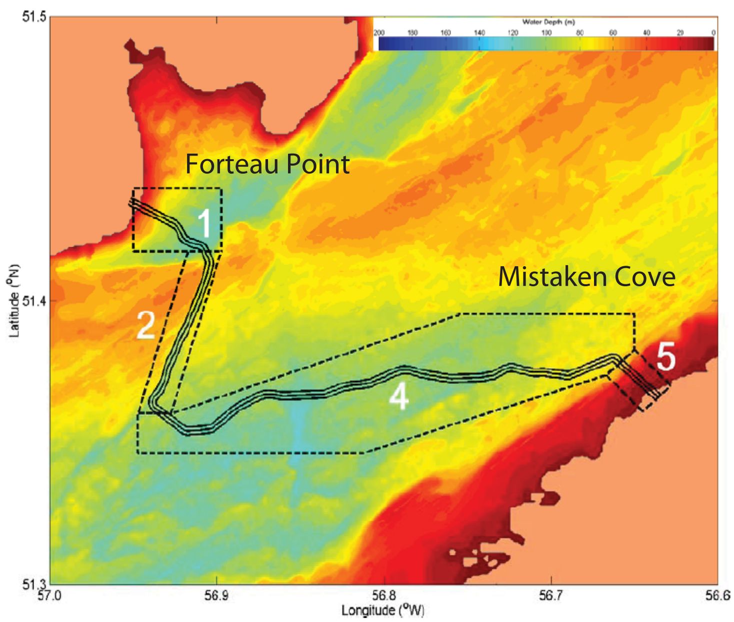

Figure 13: Strait of Belle Isle marine crossing route[171]

[171] Exhibit CE-44 Rev.2 (Public), Nalcor, "Strait of Belle Isle Marine Crossing 'Phase 2' Conceptual Design", May 2011

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

To define cable protection requirements, the corridor was subdivided into the following zones:

Table 21: Marine Crossing Zone Definitions[172]

Zone	Features
1 - Labrador landfall	starts on land 150-1000 m from the shoreline and extends to a water depth of 65-85 m. Protection is required for tidal impacts, pack ice, icebergs, and fishing
2- Deepwater Channel	400-750 m wide; starts on the Labrador side up to the midpoint on the route. Protection is required for vessel traffic (dropped objects) and fishing
3 - Eastern Corridor	65-75 m water depth from the Labrador landfall to the Deepwater Basin. Protection is required for vessel traffic and fishing and iceberg scour
4 - Deepwater Basin	100-120 m depth from Deepwater Channel to the Newfoundland landfall. Protection is required for vessel traffic (dropped objects) and fishing
5 - Newfoundland Shore	about 10 km,16-85 m depth

8.1.1 HVdc Cables

The design envisages three (two load carrying plus one spare) single core conductor cables, each rated 450 MW at ±320 kV, with 150% continuous and 200% transient overload capabilities. The cables will have mass impregnated paper insulation, are double wire armoured in a counter-helical fashion to maximize pulling tension and provide rock armouring.

8.1.2 Fibre Optic Cable

Fibre optic cable will be constructed as an integral part of the conductor as opposed to a separate cable tied with straps to the pole cable.

8.1.3 Transition Compound and Terminations

At each side of the crossing, all three cables will terminate at a transition compound, to be designed, supplied, and constructed by the Engineering Procurement and Construction Management (EPCM)

[172] Exhibit CE-44 Rev.2 (Public), Nalcor, “Strait of Belle isle Marine Crossing ‘Phase 2’ Conceptual Design”, May 2011

contractor. It is envisaged that the cables will be pulled to shore through the bore holes made by the HDD and then land trenched to the location of the transition compound. The compound location will likely be located 150 m to 1000 m inland from each shoreline. The compound will house the cable terminations, as well as any switchgear, insulators, and ancillary equipment that are required for system operation. Actual footprint and height of the compounds will be determined by the EPCM contractor and will be based on isolation requirements and installation techniques of the terminations.

8.1.4 Landfall - HDD

For both shore approaches, HDD will be utilized to protect the cables and will run from the shore to a point on the sea floor within the designated piercing target zone. This point is assumed to be approximately 1.25 km and 2.7 km from Forteau Point and Mistaken Cove, respectively (see Figure 14 having assumed a piercing depth of 80 meters).[173] The HDD solution will provide steel-lined boreholes for each shore approach.

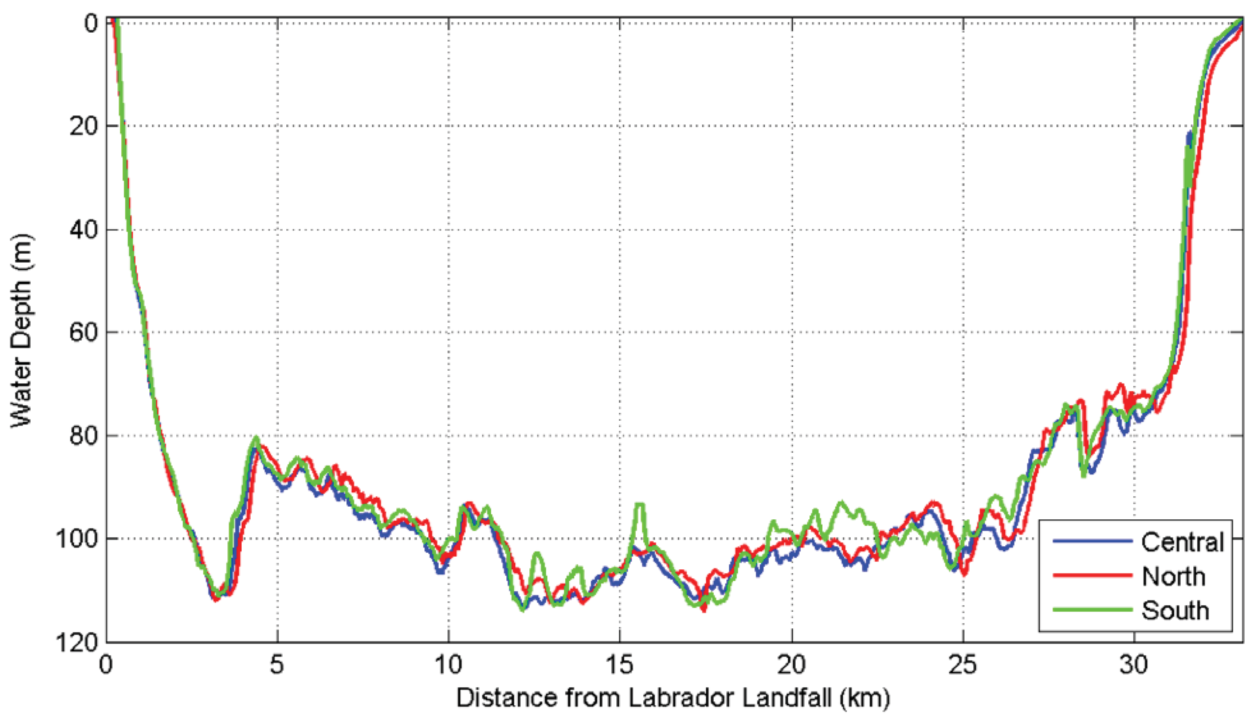

Figure 14: Water depth for the three cables of the link

8.1.5 Deepwater Zones – Rock Berms

For the deepwater zones, rock berms will be utilized to protect the cables both on the Newfoundland and Labrador sides of the Strait of Belle Isle.

[173] Exhibit 35, C-CORE, "Iceberg Risk to Subsea Cables in Strait of Belle Isle", June 2011, pg. 178

Each cable will be protected by a dedicated rock berm; preliminary studies recommend that the rock berm will be 0.5 - 1.5 meters high, 8 -12 meters wide at the base and will have a side slope ratio of 1:4 (rise:run).

8.2 Scope of Review

CESI worked as part of the MHI team on this project reviewing key documents and reports which have been produced for this portion of the project. This review was to establish if the work was performed for Nalcor with the due care and diligence employing required practices and procedures normally completed in the performance of similar work.

Specific aspects of the documentation and reports were addressed for the verification such as:

- the existence of adequate and reliable source documents
- the accuracy and relevance of the inputs included in each report
- the methodology used to create each report
- the accuracy of the estimates or assumptions made in the existing analyses
- the presence of gaps or related issues in the existing studies, analyses and reports.

8.3 Approach to the Technical Assessment

In order to be acquainted with the context of the Strait of Belle Isle cable crossing project, CESI and MHI received and examined a significant number of reports released by Nalcor's consultants and met with one, C-CORE, to discuss their work on the project.

CESI is an Italian based consultant which provides services to utilities with respect to undersea cable technologies. CESI, as a subcontractor to MHI, reviewed documentation supplied by Nalcor Energy which they had used in arriving at their recommendation to develop the option for crossing the Strait of Belle Isle with three 450 MW, ±350 kV cables.

CESI commented on the reports, all of which are very recent and examined various options for the cable crossing. CESI generally agreed with Nalcor's selection of the preferred alternative which included HDD as a means of shore approach for the cable and laying the cable on the seabed with a rock berm protection scheme. CESI have made comments and recommendations related to the findings of the consultants and Nalcor's reports; these are noted in this report.

8.3.1 Boskalis 2010 Shore Approach Feasibility Study[174]

The Boskalis 2010 study reviewed the "technical feasibility of dredging and backfilling a shore approach for the HVdc cable crossing between Forteau Bay, Labrador and Mistaken Cove, Newfoundland."

The study focused on site conditions, work methods to be used, estimated volumes of material for three optional depths of trenches and various means of backfilling and protecting the cable.

The shore approach trenches would have been dredged, and cables laid in one trench, 0.5 meter apart. However further work was required to establish the heat transfer capability of the backfill material and once known, may have required three separate trenches which would have added substantially to the costs and may have required two work seasons to complete. Costs for this component of the overall project were very preliminary due to many unknowns at this point.

The report was based on a preliminary analysis of the site and a review of past studies conducted in the area. Significantly more investigation would have been required before a detailed design and more accurate cost estimate could be established. The proposed work methods and equipment to be used were in keeping with industry standards for this type of project. However much more would have to be known of the impact of ice, wave action and the underlying geological conditions. Due to risks to the cable of this type of shore approach, it was abandoned in favour of other options.

8.3.2 Hatch 2010 Feasibility Study of HDD for the Strait of Belle Isle[175]

The Hatch 2010 study reviewed the HDD method for construction of the shore approaches for the HVdc cable crossing. This technology has matured and allows for drilling on shore to a target zone on the seabed below which damage is unlikely to occur from icebergs or currents.

The Labrador side would require drilling approximately 1200 metres, whereas the Newfoundland side would require drilling approximately 2700 metres to a required ocean floor target zone, 80 metres below the water surface. These lengths of drilling are technically feasible, although the latter is approaching the limit of HDD technology. As stated in the report, risk assessments were completed for each crossing location, but the geological and installation risks should be evaluated and updated during design and before construction. The report goes on to state "the required casing pipe diameter, and subsequent bore diameter impacts the risk levels for this project." Costs of course will be dependent on the diameter of the bore hole.

The feasibility report adequately reflects the requirements for an HDD project of the planned magnitude. The geology of the two approaches has been studied but will require refinement before construction is undertaken. Previous reports did provide a good background and potential risks were documented. The cost estimates provided are reasonable for an HDD project of this scope but will also require refinement as more details become known. Risk mitigation measures were provided and a plan developed for a test pilot bore investigation.

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[174] Exhibit CE-40 Rev.2 (Public), Boskalis, "Shore Approach Feasibility Study – Strait of Belle Isle (SOBI) Cable Crossing", November 2010
[175] Exhibit CE-41 Rev.2 (Public), Hatch, "Feasibility Study of HDD for the Strait of Belle Isle", 2010

The HDD technology proposed would meet industry standards and thus is a technically feasible solution for the Strait of Belle Isle HVdc cable crossing.

8.3.3 Tideway 2011 Rock Berm Concept Development Study[176]

The Tideway 2011 Report has evaluated the rock berm concept as a means of protection for the submarine cables for the Strait of Belle Isle crossing.

The three HVdc cables are to be laid on the seabed when they emerge from the HDD bore holes some 80 meters below the water surface. The cables are planned to be protected to avoid iceberg damage, bottom fishing trawls, and ship's anchors. Tideway consultants have a standard they use for rock placement, rock sizes and rock stability to ensure stable and permanent protection. The water is as deep as 130 meters along the cable length but they concluded that rock dumping is feasible along the majority of the route. Larger rock is to be used in the shallow water (4 to 16 inches) and smaller rock (1 to 5 inches) in the deeper sections. They also reviewed two options for spacing – a nominal spacing of three metres between each cable and therefore one rock berm or cables spaced sufficiently apart so that the individual berms do not interact. The single berm is more cost effective but increases the risk of a single occurrence damaging all three cables.

The report has provided recommendations in keeping with sound rock berm construction practices. The assumptions concerning the logistics are conservative and their research of iceberg damage, naval vessels, that could be deployed, and method of rock placement was well documented. The rock sizes to be used in the berms and the planned thickness of the berms are in compliance with standards to protect the cable from the dangers described. Further detail design would be required when the decision is made to build one or three rock berms.

8.3.4 Tideway 2011 Shore Approach and Landfall Study[177]

This Tideway 2011 study reviewed three alternate means to bring the cables ashore both on the Labrador coast with a landing area in the vicinity of Forteau Bay and on the Newfoundland side in the area of Mistaken Cove. The Tideway study also recommended a trench excavation solution.

The Labrador side would require an excavation of approximately 750 metres in length to reach a water depth of 20 metres whereas the Newfoundland side would require 2300 metres of excavation to achieve protection for the cable. Tideway suggested that it would take two construction seasons to accomplish this work. They stated that "the burial requirement for the cable in the shore approach area depends on the potential impact of pack ice on the seabed and is expected to be between a minimum of 2m and a maximum of 4m." The study also stated that, "the most common landfall installation technique is an open excavation trench" with either a rock groin or cofferdam protecting the trench. They also discussed horizontal directional drilling as an option for shore landings. A third method evaluated was tunneling including new techniques of entering the ground on an angle. Tideway favoured open excavation as the most cost efficient methodology.

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[176] Exhibit CE-42 Rev.2 (Public), Tideway, "Lower Churchill Project Rock Berm Concept Development Study - Study Report", May 2011

[177] Exhibit CE-43 Rev.2 (Pubic), Tideway, "Lower Churchill Project Shore Approach Feasibility Study - Study Report", February 2011

It would appear that the proposed trench excavation solution was reasonable but there is a lack of detailed information and weather constraints do not appear to have been adequately addressed. Given the potential for weather and ice delays, the schedules may be inaccurate which may result in higher project costs. The 20 metre depth of water considered for cable burial near the shore may also be insufficient to avoid damage to the cable due to icebergs.

8.3.5 Nalcor's Strait of Belle Isle Marine Crossing "Phase 2" Conceptual Design 2011[178]

Nalcor used the information from previous studies to develop a technically feasible solution for extending the HVdc transmission system across the Strait of Belle Isle.

Nalcor selected a corridor with an estimated length of 36 km with approximately 32 km on the seabed. They selected a single core cable with or without an integrated fibre optic core with mass impregnated paper for insulation and double wire armour cover to maximize pulling tension and provide protection against rock cover. The cables would each be rated to carry 450 MW at ±320 kV. As stated in the report, all three cables would terminate at a transition compound located 150 metres to 1000 metres from each shoreline. For both shore approaches, HDD was selected to protect the cable and would run from the shore to a point on the seafloor in at least 80 meters of water. Cable installation would be in the steel-lined bore holes but will require at least one subsea joint. Rock berms would be deployed to protect the cables in deep water. A feasibility study execution plan was scheduled to be completed by year end 2011. A Westney Risk Assessment was also conducted and major risks identified. One of the major risks is the long lead times necessary to order cable and book the installation vessel.

CESI noted a concern about the lack of information regarding the cable laying vessels and the proposed plan for jointing and covering the joint area. It was thought that the quantity of mattresses proposed may be insufficient to cover the joints in the event of a repair. Also, a single layer mattress cover may not be adequate depending on the water depth and currents. There did not appear to be any consideration given to having a spare Remotely Operated Vehicle (ROV) on hand during cable installation as a breakdown of equipment could seriously delay the project.

8.3.6 Technical Note – Strategic Risk Analysis and Mitigation[179]

This document is being updated regularly by Nalcor and generally denotes areas where concerns should be addressed. While it is lacking details due to design being incomplete, the report would appear to be adequately covering all aspects of the project. Project schedules, construction tactics and mitigation actions have been documented. This report will be continuously reviewed and updated in advance of construction.

Nalcor indicated that they were in contact with suppliers to ensure that identifiable risk areas for the SOBI marine crossing were considered. Westney uses an interactive statistical process which is effective in both establishing risks as well as assessing the range of risk exposure.

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[178] Exhibit CE-44 Rev.2 (Public), Nalcor, "Strait of Belle Isle Marine Crossing 'Phase 2' Conceptual Design", May 2011
[179] Exhibit CE-52 Rev.1 (Public), Nalcor, "Technical Note : Strategic Risk Analysis and Mitigation", July 2010

There are no apparent gaps in the process at present but the project is in the early stages and a re-evaluation of risks should be undertaken at each decision point.

8.3.7 AMEC Report – Summary of Ocean Current Statistics – 2010[180]

AMEC reviewed and summarized available ocean current data for the SOBI crossing to produce estimates of the mean and maximum expected current speeds along the corridor route. They segmented the SOBI into “three horizontal sectors (north, center and south) and three depth levels (near surface, mid-depth and near bottom)”. They also defined four distinct seasons as currents vary with each. Historic records were very sparse and did not represent a reasonable sample. Tidal conditions only represent a component of current speed but sufficient data is available to provide accurate estimates of dominant tidal constituents.

The consultants had very little data upon which to produce their findings. However the impacts of deviations from the norms would probably have little impact on the cable or the rock berm protecting it. Having a complete set of predictable data would make the task of establishing accurate current estimates easier. Having more information about mean and maximum currents near the seabed would be beneficial in establishing the rock berm size and shape necessary to protect the cables.

8.3.8 Canning & Pitt Associates Inc. Review of Fishing Equipment Report 2010[181]

Canning & Pitt prepared a baseline marine fisheries report in preparation for the Strait of Belle Isle Environmental Impact Statement. A number of methods have been investigated to protect the cable on the seabed portion of the line. The preferred choice of cable protection includes HDD for the shore portions and a rock berm covering the cables on the seabed. The scope of this study identified specific types of fishing gear and related equipment that may possibly come in contact with cables or the rock berm once installed. A five km area was studied on either side of the transmission corridor.

Scallops are the species most often fished in the area and the practice includes harvesting equipment which is towed over the seabed. Fishers in the area were contacted to provide information about the proposed cable corridor and allow them to ask questions about the possible impacts. It was established that no other fishing gear used commercially with the exception of purse seines posed any problems for the cables. Scallop dredges/rakes do present a potential threat to the proposed cable corridor and thus have to be controlled in the area. The only issue not highlighted in the report is the reaction of the fishers to the intrusion of the cables and rock berms in an area which had no interference previously. They have been consulted but additional consultations should continue to ensure that both parties have a clear understanding of what actions are required to ensure the fishery is permanently maintained. The cable route must be clearly identified so that interference is minimized. Fishers must be communicated with regularly as there have typically been claims for losses and compensation for habitat loss in similar circumstances globally.

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[180] Exhibit 33, AMEC, “Summary of Ocean Current statistics for the Cable Crossing at the Strait of Belle Isle”, August 2010
[181] Exhibit 34, Canning & Pitt, “Review of Fishing Equipment – Strait of Belle Isle”, December 2010

8.3.9 C-CORE and Fugro Geo Surveys Iceberg Risk to Subsea Cables in Strait of Belle Isle – 2011[182]

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

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

The Monte Carlo mathematical modelling techniques are well founded and provide a suitable estimate of iceberg strikes. The fact that this was the first ever study of the scouring potential of icebergs in the Strait of Belle Isle gives some cause for concern. Additional data sets and historical seabed investigations would have provided a higher degree of certainty in the simulation results.

8.3.10 Nalcor Energy Strait of Belle Isle Decision Recommendation – 12 October, 2010[183]

Nalcor Energy stated that two options for crossing the Strait of Belle Isle with the HVdc cables have been screened:

- *"Option 1 is the seabed crossing*
- *Option 2 is the tunnel or conduit crossing."*

Both options considered various technologies including the cables, installation, repair and maintenance, and protection.

Nalcor laid out conceptual designs for both options and then evaluated the risks of each, including monetary considerations. Nalcor has developed their own risk matrix with consideration to technical feasibility, safety, cost, schedule, contingency planning and geological complexity. There were five major risks associated with the tunneling option whereas the seabed option had none. HDD technology is advanced to the stage where it is practical to directionally drill and target an area for

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[182] Exhibit 35, C-Core, "Iceberg Risk to Subsea Cables in the Strait of Belle Isle", June 2011
[183] Exhibit 37, Nalcor, "SOBI Decision Recommendation", October 2010

egress at least 80 meters below the water surface reducing the risk of strikes. Thus the seabed option was recommended to be carried forward to the Environmental Assessment and detailed design stage.

Nalcor's recommendation on the Strait of Belle Isle marine crossing is a good synthesis of the conclusions of source documents, and represents a sound decision-making process. Detailed design will lead to more accurate cost estimates but those represented for this stage, can be considered realistic and conservative. It is also assumed that the schedules and cost estimates for the marine operation are inclusive of weather contingencies and a reasonable allowance for equipment downtime.

Since Nalcor's review is based on other documents, its accuracy and completeness is dependent upon those attributes and completeness in preceding documents. Having reviewed those reports, it is agreed that their recommendations are well founded.

8.3.11 Nalcor Energy Request for Proposal for Strait of Belle Isle Submarine Cable Design, Supply and Install – August 2011[184]

Nalcor's request for proposal (RFP) for the Strait of Belle Isle submarine cables was issued in August, 2011 and reviewed by CESI. The document describes the scope of work and asks for a preliminary execution plan to establish the proponents approach, commitment, and ability to carry out the work. The general specifications and requirements are in line with industry standards, including the materials and equipment to be used on the project.

8.4 Cable Risks Assessment

The Confidential Exhibit CE-52 which describes the Strait of Belle Isle cable crossing as an engineering/technical risk was reviewed by CESI and MHI. Nalcor developed strategies to mitigate the identified risks which brought the potential impacts down to a reasonable range. Such mitigation included additional feasibility studies on shore approach and iceberg risk, utilizing a spare cable, appropriate cable protection methods, along with the selection of a more mature and proven MI cable technology. Even with the actions taken to reduce risk, there is still a risk of cable failure during operation. This section quantifies the likelihood of a failure, and highlights industry recommendations to mitigate failure.[185]

Cable failure rates based on historical performance data are required to estimate the impacts, severity, and consequences of a cable failure. Review of available literature, in-depth review and technical knowledge of the application, and data from suppliers will allow Nalcor to design an appropriate cable protection system.

Both land and submarine cable failures do occur and are quantifiable. However, the difficulty is that good historical information is not readily available.

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[184] Exhibit CE-55 Rev.1 (Public), Nalcor, "Request for Proposal (RFP) No. LC-SB-003 Strait of Belle Isle Cable Design, Supply, and Install", August 2011
[185] CE-52 Rev.1 (Public), Nalcor, "Strategic Risk Analysis and Mitigation"

Two key documents used are:

- Cigré TB 379, "Update of Service Experience of HV Underground and Cable Systems", April 2009. Working Group B1.10

  Cigré WG B1.10 study was undertaken to collect and analyse data relating to the installed quantities of underground and submarine cable systems rated at 60 kV and above. More than 33,000 circuit km of underground (land) cables and approximately 7000 circuit km of submarine cable systems were identified as being in service at the end of 2005. The data collected is representative of the reliability performance based on trends in technology, design and service experience.

- Cigré TB 398, "Third-Party Damage to Underground and Submarine Cables", December 2009, Working Group B1.21.

  Failure statistics show that the risk of third-party mechanical damage is three to five times higher than the risk of internal failures for cable systems. Methods on how to reduce the number of damage events to the cables are discussed in Technical Brochure 398.

  To determine methods to reduce the number of failures caused by third-party damage, a survey was conducted by Cigré Working Group B1.21. The objective of this study was to investigate possible ways of reducing the risks of third-party damage. The Technical Brochure discusses the results of this survey and takes into account the failure statistics from TB 379.

8.4.1 Reliability Predictions

In April 2009, Cigré Working Group B1.10 completed TB 379 "Update of Service Experience of HV Underground and Cable Systems". It compiled the results of a power utility survey completed in December 2005. Results of the survey showed a trend continuing toward application of XLPE ac cables to replace self-contained fluid-filled (SCFF) ac cables, spreading to the highest voltages, i.e. 500 kV. Unfortunately there was very little data on the performance of HV cables in the range of 220 – 500 kV. For dc applications, the survey showed MI cables continuing to dominate, but with XLPE cables used more frequently up to 150 kV.

The TB 379 survey data reported that internal failure probabilities are zero for MI dc submarine cables[186]. There is an acknowledgement, however, that some of the failures reported as 'other', could have been internal. Of course a zero failure rate is unrealistic because it would infer infinite cable life, whereas it is commonly accepted that cable systems have a design life of 40 to 50 years under normal loading and maintenance conditions.

Table 30 in TB 379 also indicates that the Failure Rate for causes External and Unknown is 0.0998 failures / 100 km-yr. There are a total of 18 events[187] that define cable failures for this class of cable (MI dc). External causes (11 events) include cable damage as a result of a third party mechanical

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[186] Cigré TB 379, "Update of Service Experience of HV Underground and Cable Systems", April 2009. Working Group B1.10, Table 30

[187] Cigré TB 379, "Update of Service Experience of HV Underground and Cable Systems", April 2009. Working Group B1.10, Table 28

damage such as an anchor, or fishing trawler, or excavation activities. Other causes (five events) were defined as physical external influences which may include subsidence, or abnormal external system conditions (i.e. lightning). Unknown causes account for only two events.

Since there is no dependable and statistically significant data base on submarine cable failure statistics for internal failures (Internal failures are defined as insulation breakdown, manufacturing defects, or improper installation), this does not infer that Nalcor should not expect submarine cable failures. For example, the authors are aware of the following apparent internal submarine cable failures that have occurred within the last decade[188]:

2003, England – France 270 kV HVdc cable:

- A fault 4 km from UK at a 20 m depth. Buried cable was found twisted and failed after 17 years of service, apparently due to initial installation difficulties.

2004, New Zealand 350 kV HVdc cable:

- One of the three buried cables had a fault at 150 m away from the North Island landing point, apparently due to initial installation difficulties.

2009, Long Island Sound 138 kV ac XLPE cable:

- One of three buried cables failed within one year of installation, without signs of external aggression.

Two examples have causes yet to be determined or disclosed.

2010, NorNed 450 kV 580 km HVdc cable:

- This HVdc cable, the longest submarine cable in the world, has had two highly publicized cable failures. The first lasting four months beginning January 2010, and another in April 2011. It is unknown if these failures were due to internal causes, or joint failures.

2010, Moyle Interconnector two Monopolar 250 kV HVdc 55 km submarine cables. The Moyle Interconnector, which went into service in 2001, consists of two separate 250 MW cables running 63 km between converter stations in Northern Ireland and Scotland. Moyle has a total capacity of 500 MW.

The following failures may be attributed to anchors.

- 2010-09 – cable fault on one of two 250 MW cables which reduced the Interconnector's capacity to only 250MW for a period of 69 days. As the construction of the Moyle cables is particularly complex, the repair process required specialist personnel, tools, equipment, materials and methods, along with civil engineering works to produce a controlled environment.

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[188] Manitoba Hydro, "Potential Use of Submarine or Underground Cables for Long Distance Electricity Transmission in Manitoba", 2011

- 2011-6-26 – Pole 1 of the Moyle interconnector came out of service as a result of a fault. Testing has established that the fault is located offshore, approximately 17 km from the Northern Ireland coast in a water depth of 140 m. Work is ongoing to identify and repair this fault.
- 2011-8-24 – a fault was recorded on Pole 2 Moyle electricity interconnector. Testing has shown the fault to be located offshore, approximately 3 km from the Scottish shoreline in a water depth of 20 m.

For calculating failure rates based on the survey results, normally both the internal and external failure rates are added together to provide a total. In the case of MI dc cable in the 220 – 500 kV voltage class, the total failure rate would be 0.0998 failures / 100 km-yr as the internal cable failure rate. The SOBI installed cable length is 3 X 36 km over the circuitous route for a total length of 108 km. For this cable based on industry available data, Nalcor could expect that there will be 5.3 cable failures or one cable failure every ten years, approximately. It should be noted that the statistics and the resulting failure rate may not apply to the Strait of Belle Isle due to its location, pattern of naval traffic, and use of cable protection.

Installation of the planned third cable will alleviate the risk of a prolonged outage as full service can be restored in the time it would take to switch in the spare cable, and to take the faulted or damaged cable out of service. There will be a loss of transfer capability as there is only a 150% continuous overload rating on one pole of the HVdc system. Subsequent to a fault it is imperative that steps be taken to repair the damaged cable. As noted in the report, the following steps are generally taken to repair a cable: [189]

- *"Fault Finding*
- *Securing of repair vessel contract*
- *Planning of repair operation*
- *Mobilization of repair vessel and equipment*
- *De-burial of the faulty cable portion*
- *Loading of spare cable and jointing kit*
- *Jointer crew embarks*
- *Repair effected and protection re-established."*

Repair times may be long (many months) as conditions in the Strait of Belle Isle and the availability of repair vessels, and equipment may hamper repair efforts.

8.4.2 Third Party Damage to Submarine Cables

Table 5.7 in the Cigré TB 398, indicates that the sample size for the failure surveys for MI dc cable was 5239 km of installed cable up to 2005. The failure rate is the same as noted previously. However, it is interesting to note that for external failures the failure rate for anchor damage is 0.02 while for trawling it is 0.03. Unknown failures account for the rest at 0.05 failures per 100 km-yr.

[189] Exhibit CE-44 Rev.2 (Public), Nalcor, "SOBI Marine Crossing Phase 2 Conceptual Design ", May 2011, pg. 29

A number of cable protection systems are described and recommended for submarine cable systems including trenching, tunneling, jet plow, and rock dumping. For the SOBI marine crossing route, a high percentage of the seafloor on the designated cable route consists of bedrock with minimal overburden[190]. According to the SOBI Marine Crossing Phase 2 Conceptual Design report, rock trenching was eliminated as a means of protecting the cable due to the hardness of the bedrock since the technology does not exist.[191]

Cigré TB 398 recommends that for cases where trenching is not possible, the use of concrete mattresses, rock dumping, or both be considered. The use of HDD is also recommended when in close to shore to protect against wave action, or in the case of Strait of Belle Isle, icebergs. The "Lower Churchill Project Rock Berm Concept Development Study Report", CE-42 Rev. 2 (Public) by Tideway BV studied the use of a rock berm and found that this is feasible and will provide appropriate cable protection along the cable route for depths of 40 m to 110 m.

8.4.3 Life Expectancy of Cable Systems

Cable systems are typically designed and tested on the basis of a 40 year life. Actual longevity can exceed this time if loading is not excessive and regular maintenance programs are followed. There is a growing trend to acknowledge that a 50 year actual life may be more realistic, based on service experience with cables less than 500 kV. Comparing this with an approximate 100 year life for overhead line alternatives leads to the conclusion that an underground or submarine cable system would need to be replaced about once during the life of an equivalent overhead line.

8.5 Risk factors

Possible considerations which may affect the implementation of the project in terms of strategy, time and costs include:

- for the proposed long HDDs it should be considered that a failing in the drilling process is possible and would likely require a new attempt with the abandonment of the failed drill. One spare HDD could be provided per each landing, but at a significant cost.
- the schedule and cost estimate for the marine operation are dependent on the weather and downtime which may occur during operational activities.
- the reaction of fishers to the installation, i.e. whether they look at this infrastructure positively or not may be an important issue. The installation and presence of the rock berms could have an impact on the fishers. In addition, claims by fishers for losses could become an issue.
- slippage in the procurement efforts with respect to manufacturing space for cable, or the scheduling of vessels for cable laying or rock placement.

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[190] Overburden is the material that lies above an area of economic or scientific interest; most commonly the rock, soil, and ecosystem that lies above a coal seam or ore body.
[191] Exhibit CE-44 Rev.2 (Public),Nalcor, "SOBI Marine Crossing Phase 2 Conceptual Design", May 2011, pg. 24

8.6 Cost Analysis

Costs for the marine crossing cable system have been estimated by CESI for comparison purposes to Nalcor's estimate. Factors include cable manufacturing, installation, and cable protection. Costs not factored are related to aspects which require a detailed understanding of the territory such as the submarine surveys, the seabed preparation, and effect of adverse climatic conditions during cable laying/installation, maintenance and repair. The implementation plan does not consider other possible contingencies, such as HDD, which may be critical in the schedule and plan of work.

MHI has reviewed the total base cost estimate for the SOBI marine crossing at DG2 and finds it within the range of an AACE Class 4 cost estimate.

8.7 Conclusions and Key Findings

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

The conductor has been specified as a ±350 kV single core aluminium or copper cable with mass impregnated (MI) paper insulation with ratings that match the HVdc converter station capabilities. Final cable size selection will be based on a detailed engineering analysis performed by the supplier.

The SOBI marine crossing is extremely complex and poses numerous challenges for cable installation and protection. MHI generally agrees with Nalcor's selection of the route and protection scheme which includes horizontal directional drilling as a means of shore approach and laying the cable on the seabed with a rock berm.

MHI has found the following key findings from the review of the SOBI marine cable crossing:

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

contact by icebergs was reduced with greater separation of the cables. Additional research, monitoring of iceberg roll rates, and bathymetric surveys of earlier iceberg scours should be done to provide a level of validation to further tune the iceberg strike risk model.

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

9 Small Hydroelectric Plants

Report by: A. Gerrard, P. Eng.

9.1 Island Pond Development

9.1.1 Project Background

The proposed Island Pond development is a 36 MW hydroelectric project that would be constructed in the southern part of Newfoundland as part of the Isolated Island Option. The in-service date for this development set out in the generation expansion plan is 2015.

The Island Pond development has been the subject of seven studies to date. The initial desktop study was followed by a pre-feasibility study in 1986 and a feasibility study in 1988. Following completion of the feasibility study, an optimization study was carried out in 1988 and two re-optimization and cost update studies were completed in 1997. Findings from the most recent study are described in a 2006 report by SNC Lavalin.[192]

9.1.2 Basis for Review

The primary considerations for determination of the CPW contribution from a hydroelectric project are the capital cost of the project, the operating and maintenance costs and expected energy production and project capacity. Since operating and maintenance costs for hydroelectric projects are relatively low and predictable, at the planning stage the greatest uncertainty typically lies in the capital costs and expected energy production. These issues were therefore the focus of MHI's review.

MHI's review was limited to the documents provided by Nalcor, in particular Exhibit 5b "Studies for Island Pond Hydroelectric Project", Confidential Exhibit CE-57 "Capital Cost Estimates", Exhibit 52 "Island Pond Granite Canal Re-Optimization", Exhibit 53 "Island Pond Final Feasibility Study", and Exhibit 69 "Geotechnical Site Investigations Proposed Island Pond Hydro Electric Development".

The earlier studies, as described in Exhibit 5b, were conducted in a logical process involving the advancement of the level of work, optimization to consider additional alternatives and updating of cost estimates. All of these studies were carried out by consulting firms that have a credible history in engineering for hydroelectric projects.

9.1.3 Project Description and Background

The Island Pond Hydroelectric project site is located on the North Salmon River in the south-central region of Newfoundland. The project would utilize most of the 25 m of undeveloped gross head between the Meelpaeg Reservoir and the existing Upper Salmon hydroelectric development.

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

The Meelpaeg Reservoir serves as upstream storage for other plants and is already well regulated. Flow for the new project would be diverted from Meelpaeg Reservoir into Island Pond via a 3,000 m long Diversion Canal and 3,400 m of channel improvements within Meelpaeg Reservoir and Island Pond. A 750 m Forebay Canal would then convey water from Island Pond to the Island Pond Hydroelectric Project powerhouse. The powerhouse would discharge into a relatively short tailrace channel ending in Crooked Lake.

The powerhouse is envisaged to be close-coupled with the intake. It would contain a single vertical Kaplan turbine with a synchronous generator that would produce 36 MW at a rated head of 22.3 m. The powerhouse would be constructed in an excavation on the right bank of the channel between Island Pond and Crooked Lake and would abut a relatively short concrete dam.

A spillway is not required for the project since flood flows from Island Pond and Meelpaeg reservoir can be stored in the reservoir and routed through the existing regulated system.

9.1.4 Level of Site Investigations

Topography

Topographical mapping was considered adequate for a feasibility level study although further survey work was recommended prior to design.

Uncertainties in bathymetry would have the greatest potential impact on components that involve large areas and relatively shallow excavations. In the case of Island Pond, such structures include the canals, channel improvements, tailrace excavations and HADD (Harmful Alteration, Disruption or Destruction of fish) compensation areas. Since the estimated cost of these components form a significant portion of the total direct costs, any uncertainty in bathymetry could have a large impact. However it should be possible to mitigate the cost implications by redesign to accommodate the actual bathymetry and topography once this information has been established.

Subsurface Conditions

Site geotechnical investigations for the proposed Island Pond hydroelectric development were carried out as part of the 1988 studies and further investigations were carried out in conjunction with the 2006 studies. The 2006 investigation included a review of previous reports on geotechnical investigations and additional site investigations at the proposed site of the dam, powerhouse, access roads and camp.

The level of the site subsurface investigations is generally in keeping with feasibility level studies. Some areas where uncertainties remain include:

- The extent to which protection against acid generating rock, which impacts the integrity of the concrete, was uncertain. The geotechnical investigations confirmed the presence of acid generating rock in the area of the powerhouse and dam and suggested additional investigations to better delineate the extent of acid generating rock in the forebay canal and tailrace.
- The depth of overburden in the area of submerged excavations required further study. The 2006 investigations relied on the preliminary design and quantities from earlier studies due to

limitations in the 2006 scope. These quantities were reported to be based on a design that would minimize or eliminate rock excavation since rock excavation would be much more costly than overburden. Based on the results presented in Exhibit 53, it would appear that the depth to rock was only confirmed at six locations along the submerged portion of the diversion canal and the channel improvements. Given the length and large surface areas of the diversion canal and channel improvements, this leaves considerable uncertainty with respect to the profile of the top of rock in these areas. However, it should be noted that, at the final design stage and even at the construction stage, it should be possible to mitigate the impact of higher than anticipated rock elevations by modification of the design.

Construction Materials

The site investigations included an evaluation of the suitability of alternative sources of construction materials and the identification of material sources for concrete aggregate and fills.

Environmental

Exhibit 5b, the 2006 report, included updates to reflect the current requirements for key environmental issues. This included construction of HADD mitigation measures and allowance for treatment of acid generating rock.

The extent of HADD mitigation was based on an assessment of fish and fish habitat by Nalcor. In recognition of a relatively high level of uncertainty associated with the mitigation measures, a contingency of 30 % was included in the 2006 cost estimates for HADD compensation.

The 2006 report does not include any discussion of ramping effects on fish due to changes in discharge from the plant either under normal operating conditions or during an unplanned unit shut-down due to a fault. This could be due to the fact that the knowledge and emphasis on ramping effects has been dealt with only recently and was not known when the study was undertaken. While it would appear that ramping effects in the tailrace channel would not be large, this is a relatively complex issue and mitigation measures such as bypass flow release facilities could be quite costly if found to be necessary to meet current requirements.

9.1.5 Preliminary Designs

Level of Engineering

The 2006 study, Exhibit 5b, included a comprehensive review of earlier reports and files and was generally structured so as to build on work done in earlier studies. As such, the 2006 investigations had the benefit of the accumulated knowledge and engineering evaluations from previous work as well as the perspectives of the consultants who undertook those studies.

Project Arrangement

The selection of an appropriate project arrangement typically has an important impact on the technical feasibility, constructability and financial viability of a hydroelectric project.

The proposed Island Pond arrangement is relatively straightforward. The consultant that conducted the 2006 investigations states that the project is technically feasible and MHI's review did not reveal any issues that would suggest otherwise.

The 2006 studies did rely on earlier work or client decisions for some quite significant aspects of the preliminary design. These included:

Project Capacity

The project capacity of 36 MW was based on optimization studies conducted in 1997 and presented in Exhibit 52. These studies indicated that the optimum capacity for Island Pond would be about 36 MW based on 1996 energy and capacity values. The studies also showed that the relationship between Net Present Worth was quite insensitive to project capacity over a range of about 30 to 42 MW. Re-optimization of capacity for the 2006 studies would therefore not be expected to have resulted in changes to the CPW of the Isolated Island Option that would be significant in the context of the present evaluation.

Number and Type of Units

The 1997 Island Pond studies, Exhibit 52, included consideration of different unit types and numbers. Those studies indicated that,

- A plant with a single unit Francis turbine would be somewhat less costly than a two unit plant.
- A plant with two Francis units would be somewhat less costly than a plant with two Kaplan turbines.
- Comparative energy production estimates for the alternative sizes and types of units indicated that there would be little difference in annual energy production.
- If the Francis units were operated at peak efficiency, there would be little difference in energy production and this option could be chosen.

The selection of Kaplan type units for the 2006 studies is indicated to have been based on the need to allow operation at low flow during some parts of the year for environmental reasons. Based on the 1997 findings, the selection of a single Kaplan turbine as the basis for the 2006 studies would be expected to have had only a marginal impact on the project cost and energy production relative to other options.

Diversion Canal and Channel Improvements

The scope of the 2006 investigations required the consultant to use the diversion canal geometry and quantities from 1997 studies, Exhibit 52. The consultant that undertook the 2006 studies did recommend that further investigation of alternative canal and channel alternatives be investigated before final design. However, the 1997 studies, which included re-optimization of the diversion canal geometry using 1996 energy and capacity values, indicated that the Net Present Worth of the canal was relatively insensitive to the canal invert level. Based on these findings, reuse of the 1997 diversion canal parameters without re-optimization in 2006 would therefore not, for the purposes of systems planning, be expected to have significantly impacted the CPW of the Island Pond project.

Dam and Powerhouse Arrangement

The 2006 studies, Exhibit 5b, were restricted to consideration of zoned earth-fill, roller compacted concrete and conventional concrete dams or some combination of these three dam types.

The arrangement with a close-coupled intake/powerhouse in combination with a roller compacted dam was used as the basis for the 2006 quantity and cost estimates as presented in Exhibit 5b. Comparative quantities and costs were not included in the report. However, there are no obvious reasons to suggest that the selected arrangement would appear to be inappropriate and project cost estimates would not significantly impact the CPW for the Isolated Island Option.

The project arrangement as presented in the 2006 report, Exhibit 5b, is relatively straightforward. Construction sequencing and dewatering requirements have been considered, as have permanent and construction access roads, construction materials, construction facilities, reservoir clearing and mitigation of HADD. Transmission line interconnections, substations and communications arrangements were provided by the owner.

The preliminary arrangements and construction sequencing for the project are based on conventional approaches. However, it is possible that the 1988 concepts relating to the construction of the diversion canal and the channel improvements, and dewatering of Island Pond could be subject to more stringent environmental considerations than would have been applicable at the time the concepts were first developed.

9.1.6 Capacity and Energy Estimates

For a full description of capacity and energy estimates for Island Pond, see the Hydrology Report, section 2.4.

9.1.7 Construction Schedule

The 2006 report presented in Exhibit 5b, indicates that a duration of 3 ½ years would be required from commitment of the project to first power. This schedule is based on a multi-contract design/bid/build approach that allows preparatory work such as engineering and contracting to proceed in parallel with the regulatory approvals process. The 2006 schedule allows only one year for regulatory approvals based on expediting the process at every step. The schedule is also based on initiation of the process by late spring of year one in order to permit some construction activities to comply with seasonal constraints. Even a relatively small slippage in the early stages of the project could therefore result in a delay of a year. Given these constraints and the nature of the project, the schedule presented in the 2006 report is quite aggressive, especially given the ever increasing scrutiny during the regulatory process. The risk analysis carried out as part of the 2006 report identifies schedule delays as the key risk associated with the Island Pond project.

9.1.8 Estimated Costs

Capital cost inputs to the Strategist Model were entered in the form of direct capital costs in 2010 dollars and were distributed over the years in which expenditures are expected to occur in order to generate the cash flow in 2010 dollars. Escalation of the direct capital costs beyond January 2010 and the AFUDC were computed within the Strategist model.

The original scope for the 2006 study presented in Exhibit 5b called for the development of capital cost estimates with a requirement for an accuracy of ±10%. This requirement was replaced by a requirement to undertake a risk analysis of the final cost estimate. The scope of work was otherwise not specific with respect to the class or level of estimate that was to be prepared.

The estimated capital cost contained in Exhibit 5b and Exhibit CE-57 is presented in December 2006 dollars. The direct capital cost estimates for the project included:

- The various project components and an estimate for HADD mitigation measures.
- The project estimate included costs for those aspects of the project to be undertaken by the owner; primarily the telecommunications, transmission, switchyard, and control and protection required to interconnect the project to the grid. A contingency allowance of 10% was applied to these items.
- An estimate for management and engineering fees was based on 12.5 % of the direct capital costs plus contingency for the work estimated by the consultant. No separate allowance for engineering and management was provided for the work estimated by the owner.
- An estimate for owner's costs was based on 8.7% of all direct capital costs plus contingencies.[193]

The total estimated cost of the project with escalation and AFUDC was $166 million in 2010 dollars.[194]

The cost estimates are based on a fairly detailed and comprehensive breakdown of the construction quantities, equipment and facilities including construction support facilities. The estimates also include costs for management, engineering and owner's costs. Some contractor overheads such as mobilization and demobilization are not separately identified so these are assumed to be distributed amongst the unit prices for construction.

Exhibit 5b indicates that the capital cost estimates for civil works were developed with input from a contractor with experience in construction of hydroelectric plants including plants in Newfoundland. Estimates for major components such as the turbine-generator, transformers and electrical and mechanical equipment were based on enquiries to suppliers and the experience of the consultant. The consultant did conduct a risk analysis to assess the likely range of project costs. Based on this analysis it was concluded that there was less than a 10% probability that the final costs would vary from the estimated costs by more than about plus 2.6% to minus 2.4%. This would suggest a very high level of confidence. The consultant indicated that the level of engineering was considered to be at the feasibility level although quantities for the diversion canal and channel improvements were based on earlier studies. The consultant has noted some discrepancies relative to more recent survey work. The definition of environmental mitigation measures also involves significant uncertainty as does the construction schedule which is based on an aggressive methodology for regulatory approvals.

The cost estimate was not otherwise defined in terms of industry recognized class or level designations.

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[193] Exhibit 5b, SNC Lavalin, "Studies for Island Pond Hydroelectric Project", December 2006, pg. 80
[194] Nalcor's Submission to the Board of Commissioners of Public Utilities with respect to the Reference from the Lieutenant-Governor in Council on the Muskrat Falls Project, November 2011, pg. 39

Nalcor advised that the estimate for Island Pond is considered to be at the screening level or feasibility level which would suggest a much broader range of projected costs.[195] The uncertainty with respect to Island Pond would not appear to be inordinately high relative to a typical feasibility study, although reliance on work from previous studies for significant components of the work and lack of certainty with respect to some environmental and schedule related issues does introduce additional uncertainty. Given these considerations, the levels of contingency included in the Island Pond estimates appear to be quite modest. Under those circumstances and given the nature of some of the key uncertainties, the likelihood of an increase in project costs would appear to be substantially greater than the likelihood of a decrease.

The escalation applied by Nalcor to obtain 2010$ direct cost inputs for the Strategist model was compared with the Nalcor escalation factors for the Muskrat Falls project as presented in Exhibit 3. Application of the escalation factors in Exhibit 3 to the various categories of the 2006 capital cost estimates in Exhibit 5b yielded a total 2010 capital cost that was within 1.2% of the Strategist input. This difference might well be explained by differences in allocating costs to the various escalation indices presented by Nalcor.

9.1.9 Other Inputs to the System Planning Process

The feasibility study, Exhibit 5b, indicates that the rated capacity of Island Pond would be 36 MW. This corresponds to the Strategist input indicated in Exhibit 14 for the Isolated Island options.

Energy inputs have been defined in the Hydrology Study. See section 2.4 for details.

Exhibit 12 indicates that a forced outage rate of 0.9% was used for all new hydro developments in the Strategist inputs. This rate is based on the average reported forced outage rate for Newfoundland and Labrador Hydro units for the five year period prior to 2006.

An outage rate of 0.9% is somewhat lower than the average rate for units of comparable size operated by members of the CEA for the five year period prior to 2006. Outage rates do vary significantly amongst operators of hydroelectric plants due to a number of factors including maintenance practices, control and protection schemes, size and design of units, and site specific conditions amongst others. However, there is no obvious reason that maintenance practices for Island Pond should be different than for other hydroelectric plants in the NLH system. The 36 MW Island Pond turbine-generator unit would be about one half the capacity of the majority of NFL's hydro units and smaller units do generally tend to have higher outage rates. However, the Canadian Electrical Association does not distinguish between outage rates for units in the range of 24 to 99 MW. This range encompasses most of the existing NLH units as well as Island Pond. In summary, the use of an outage rate of 0.9% for Island Pond is appropriate for planning purposes.

[195] Response to RFI MHI-Nalcor-34

9.2 Round Pond Development

9.2.1 Project Background

Round Pond is a proposed 18 MW hydroelectric project that would be constructed in the Bay d'Espoir drainage basin in Newfoundland. The project is included in the Isolated Island expansion plan with an in-service date of 2020.

The Round Pond development was first investigated in a desktop study by Acres International in 1985. The investigations were upgraded in a 1987/1988 feasibility study conducted by Shawinigan/Fenco and the findings were documented in Volume 1 of a September 1988 report entitled "Feasibility study Round Pond Hydroelectric Development". The engineering department of Newfoundland and Labrador Hydro undertook companion studies of transmission, telecontrol and environmental issues and prepared a Summary Report dated February 1989 that incorporated the findings from Shawinigan/Fenco's investigations.

9.2.2 Basis for Review

The primary considerations for determination of the CPW contribution from a hydroelectric project are the capital cost of the project, the operating and maintenance costs and expected energy production and project capacity. Since operating and maintenance costs for hydroelectric projects are relatively low and predictable, at the planning stage, the greatest uncertainty typically lies in the capital costs and expected energy production. These issues were therefore the focus of MHI's review.

The required level of review was judged in the context of scale of the projects relative to the overall expenditures.

MHI's review of Round Pond focussed on:

- Exhibit 5d (i) - The February 1989 report entitled "Feasibility Study Round Pond Development, Summary Report".[196]
- Exhibit 5d (ii) - The September 1988 report entitled "Feasibility Study Round Pond Hydroelectric Development, Volume 1".[197]

The 1987/1988 investigations leading to the Exhibit 5d (ii) report by Shawinigan/Fenco commenced with a pre-feasibility study. After review of the preliminary pre-feasibility results by the client, the consultant was authorized to undertake a full feasibility study. The scope of the consultants work was modified by shifting some field investigations from the feasibility to the pre-feasibility stage and by deletion of the survey work for access routes.

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[196] Exhibit 5d(i), NLH, "Feasibility Study Round Pond Development, Summary Report", February 1989
[197] Exhibit 5d(ii), NLH, "Feasibility Study Round Pond Hydroelectric Development, Volume 1", September 1988

9.2.3 Project Description and Background

The Round Pond hydroelectric project site is located in the Bay d'Espoir catchment area at the outlet of Round Pond. The project would utilize about 11.3 of the 12 m of undeveloped head between Godaleich Pond and Long Pond Reservoir. Inflows to the project would consist of the regulated discharge from the existing Upper Salmon generating station into Godaleich Pond, which in turn discharges into Round Pond through the West Salmon River, as well as natural inflows to the Round Pond drainage basin.

Some of the head at the site would be developed by construction of a dam at the outlet of Round Pond and three saddle dams to raise Round Pond about 6 m above its natural level. The remaining head would be captured by the construction of a canal to divert outflow from Round Pond around a set of downstream rapids to the Long Pond reservoir.

The powerhouse was envisaged to be close-coupled with the intake. It would contain a single horizontal pit type turbine with a synchronous generator that would produce 18 MW at a net head of 10.8 m. The powerhouse would be constructed in an excavation downstream, at the end of the canal. Discharge from the powerhouse would be conveyed to Long Pond reservoir through a short tailrace channel. A fish passage would connect Long Pond Reservoir to a point in the intake channel just upstream of the powerhouse.

The dam at the outlet of Round Pond would take advantage of an island in the river. The island would also be used to facilitate diversion and the construction of a gated spillway that would release excess inflows to Round Pond.

9.2.4 Level of Site Investigations

Topography

Filed surveys were initially carried out for the pre-feasibility studies and subsequently advanced for the feasibility studies. The surveys were simplified by using Round Pond water levels to carry a datum established from Long Pond to a point in Round Pond that was near the outfall of the West Salmon River. This datum was then used to confirm levels between Round Pond and the upstream Godaleich Pond in order to establish the available head. The surveys indicated that the available head was almost 13 m versus the 5.8 m head assumed in the earlier desktop studies. This very significant discrepancy in datum levels substantially altered the project capacity and layout.

Ground surveys were conducted along the centerline of the power canal, powerhouse and closure dykes, and cross sections were taken at selected areas. River bed profiles were also taken at the control sections of the rapids. Long Pond water levels were used to establish a datum as there was no geodetic datum near the site. Additional ground surveys were also carried out at one of the saddle dams and the dam/causeway location.

Topographic mapping at a scale of 1:2500 was developed using the ground surveys and photographic restitution. A ground survey was used to establish control points at several locations. The consultant considered the level of topography to be adequate for a feasibility level study although further survey work on access roads, the camp area, and the east channel of the Round Pond outlet was recommended before final design. Currently, available survey techniques might result in some improvement in absolute levels but there are no obvious shortcomings with the survey data used in Exhibit 5d(ii) that would be expected to create uncertainties atypical of those at the feasibility study level.

Geological Mapping and Subsurface Conditions

Subsurface conditions frequently represent one of the major areas of uncertainty and risk for hydroelectric developments. Round Pond, Exhibit 5d (ii) indicates that initial surficial geological mapping covering most of the project was prepared from aerial photographs.

Site ground reconnaissance was combined with aerial reconnaissance using a helicopter for the access routes. An aerial reconnaissance of the proposed flooded area was also undertaken. The extent of surficial cover was examined by site probing and found to be quite thin. Samples were taken from potential borrow areas. Test pits were also excavated in the powerhouse, canal and causeway areas, and peat probing was undertaken along alternative alignments of the east saddle dam. Subsurface drilling and testing programs with six holes covering the main structure alignments, one in a saddle dam location and one in the proposed quarry area were also undertaken. Additional test pits were excavated in the two potential sources of construction materials.

The level of the site subsurface investigations was generally in keeping with feasibility level studies. One issue not covered in the report is the potential for acid generating rock. It is uncertain if the rock had the potential for acid generation or because the issue was considered to be insignificant at the time.

The results of the investigations were documented in Volume II of the feasibility study. This volume was not reviewed although the findings were incorporated in Exhibit 5d (ii).

Construction Materials

The site investigations included an evaluation of the suitability of alternative sources of construction materials and the identification of material sources for concrete aggregate and fills.

Environmental

The report contained in Exhibit 5d (i) indicates that concerns had been expressed concerning waterfowl breeding habitat, caribou, raptors, and moose. It also indicates that the potential impact of the project on fish passage. The Long Pond spawning habitat on the West Salmon River was one of the major concerns.

NLH decided to defer initiation of most environmental impact studies although a small amount of work was done on the fish passage issues. Estimated costs for environmental work included provision for fish passage at the generating station and estimated costs for conducting an environmental impact assessment and monitoring. Since environmental requirements have generally become more onerous since 1988, it is quite likely that the scope of work envisaged in 1988 would have been less comprehensive than dictated by current requirements. In addition, there does not appear to be any provisions for mitigation aside from the fish passage facilities. Consequently, this is an area where there would appear to be a need for additional work in order to meet current practices for a feasibility level study.

9.2.5 Preliminary Designs

Level of Engineering

The 1988 study documented in Exhibits 5d (i) and 5d (ii) initially involved prefeasibility level studies followed by advancement of the engineering to a level that is presented as feasibility level.

Project Arrangement

The selection of an appropriate project arrangement typically has an important impact on the technical feasibility, constructability and financial viability of a hydro-electric project.

The proposed Round Pond arrangement is relatively straightforward. The consultant that conducted the 1988 studies states that the project is technically feasible and MHI's review did not reveal any issues that would suggest otherwise.

The 1988 studies included the investigation of alternative arrangements and project parameters, some of which are summarized below.

Reservoir Level and Project Capacity

The maximum reservoir level was established on the basis of environmental considerations arising from work done for the next most upstream project. The selected reservoir level sacrificed about 1 m of the available gross head. While this came at the expense of project capacity and energy, any benefits arising from a higher capacity would have been offset at least to some extent by the costs for higher and more extensive water retention structures at Round Pond. Optimization of the reservoir level indicated that a higher reservoir level would not reduce the cost of energy although the benefit cost ratio for the project would be somewhat improved.

A capacity optimization study indicated that an 18 MW plant would provide the lowest cost energy at the selected reservoir level.

Updating of the 1988 studies using present day costs and values for energy and capacity may produce different conclusions regarding the optimum capacity and reservoir level.

Number and Type of Units

The pre-feasibility studies included investigation of alternative unit types and numbers. Those studies indicated that a single pit turbine would provide the best solution and would provide a savings of about 5% of the direct project costs relative to a single vertical Kaplan unit. Pit turbines were a relatively recent development in 1988. Updating of the unit selection to consider the most recent developments could result in some changes to the unit. However, it is expected that these changes would not have a major impact on the project economics.

Overall Project Arrangement

The investigations included consideration of a range of alternative arrangements for the causeway, saddle dams and main structures. These investigations provided a basis for selection of a cost effective and technically acceptable arrangement for the feasibility study although the consultant did recommend the investigation of additional arrangements if the project proceeded to final design.

The project arrangement as presented in the 1988 report is relatively straightforward. Construction sequencing and dewatering requirements have been considered as have permanent and construction access roads, construction materials, construction facilities and reservoir clearing. The project arrangement was however developed without the benefit of environmental studies. Developments since 1988 would likely increase the potential impact of environmental considerations since the project involves significant inundation and creates a barrier to fish passage.

Requirements for the transmission line interconnection, substations and communications arrangements were provided by the client. These requirements and the associated estimates of costs are documented in Exhibit 5d (i).

Aside from the selection of a relatively new type of turbine for the application, the preliminary arrangements and construction sequencing are based on approaches that are fairly conventional. Experience subsequent to 1988 has confirmed the pit turbine concept for many applications although these have tended to be in projects with lower capacities. One of the major uncertainties with respect to the Round Pond project is that it could well be subject to more stringent environmental considerations than would have been applicable at the time the concepts were first developed.

9.2.6 Energy Estimates

The capacity and energy estimates for Round Pond are contained in the hydrology report, section 2.3.

9.2.7 Construction Schedule

The schedule presented in Exhibit 5d (ii) indicates that a duration of 33 months would be required from commitment of the project to first power. This schedule is based on a multi-contract design/bid/build approach that allows preparatory work such as engineering and contracting to proceed in parallel with the environmental investigations and regulatory approvals process. The schedule assumes that regulatory approvals would be achieved in year one of the program. It is also assumes that some construction would start in Year one. Since the schedule will also be governed by seasonal constraints on several construction activities, a slippage in the early stages of the project could result in a delay of one year.

Given the nature of the project, the schedule developed for the 1988 studies is very aggressive, especially given the trend towards increased scrutiny during the regulatory process. However, since Isolated Island Option does not require commercial operation of the Round Pond project until 2020, a substantially longer project development schedule could be readily accommodated.

9.2.8 Estimated Costs

Capital cost inputs to the Strategist Model were entered in the form of direct capital costs in January 2010 and were distributed over the years in which expenditures are expected to occur in order to generate the cash flow in January 2010. Escalation of the direct capital costs beyond January 2010 and the AFUDC were computed within the Strategist model.

The consultant's scope for the 1988 study presented in Exhibits 5d (II) called for the development of capital cost estimates. The scope of work was otherwise not specific with respect to the class or level of estimate that was to be prepared.

The estimated capital costs contained in Exhibit 5d (ii), the report by the consultant, and Exhibit 5d (i), the summary report with additional cost components developed by the owner are presented in July 1988 dollars. The direct capital cost estimates for the project included:

- $53.7 million for the direct capital costs for the project components within the consultant's scope. This included an estimate for a fish passage facility at the powerhouse but no other allowances for environmental costs.
- $6.8 million for the direct capital costs for those aspects of the project included in the owner's scope; primarily the telecommunications, transmission, switchyard and control and protection required to interconnect the project to the grid. This also included an estimated cost of $870,000 for environmental investigations and preparation of an EIS and environmental monitoring and estimates for engineering and management for the items described above.
- An estimate for management and engineering of $6.4 million based on a 12% of the direct capital costs before contingency for the work estimated by the consultant only.
- An estimate of $3.4 million for owner's costs based on 5.1% of all direct capital costs plus contingencies.
- An estimate of $6.4 million for contingencies. This corresponds to 10.5% of direct capital costs.[198]

The total estimated cost of the project before escalation and AFUDC was $76.8 million in July 1988. Estimates of escalation and AFUDC were also presented in Exhibit 5d (i) and 5d (ii) but these were not used in the Strategist input for the CPW calculations.

The estimates include costs for management, engineering and owner's costs. Some contractor overheads such as mobilization and demobilization are not separately identified so these are assumed to be distributed amongst the unit prices for construction.

The cost estimates are not defined in terms of industry recognized class or level designations but have been presented as feasibility level estimates. The application of only a 10.5% contingency would typically suggest that the consultant had a fairly high level of confidence in the estimates but there is little basis to judge whether or not this confidence is justified. The fact that environmental requirements have changes so dramatically since 1988, it is expected that the contingency is low. The discussion of the estimating methodology in Exhibit 5d (ii) indicates that the capital cost estimate was based on cost trends and unit prices that had been observed in Newfoundland as well as "target estimates" from manufacturers and suppliers. The cost estimates are only presented in Exhibit 5d (i) and (ii) at a summary level. Nalcor advised that neither further breakdowns of the construction quantities, equipment and facilities nor other back-up was available. Consequently, it is not possible to comment on the level of detail that was considered in developing the estimate. No major omissions were evident. However the following observations are noted:

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[198] Exhibit 5d(ii), NLH, "Feasibility Study Round Pond Hydroelectric Development, Volume 1", September 1988, pg. 9-7

- Since 1988 there has been significant evolution of environmental standards and the associated regulatory processes. Since the project would involve significant construction activities, significant inundation and the creation of a barrier to fish passage amongst other possible environmental issues, it is quite possible that the project arrangement could be impacted and additional expenditures could be required for mitigation.
- The allowances for owner's costs as a proportion of total costs are significantly lower than for Portland Creek or Island Pond.
- The impoundment of Round Pond would result in a onetime reduction in energy production from downstream plants. The value of lost production was estimated to be $2.3 million based on 1988 values for energy.
- The schedule is fairly aggressive, especially in light of the current regulatory environment.

All of these factors would suggest that developments since the time of the study would lead to increased project costs.

The escalation of costs from 1988 to 2010 involves a substantial level of uncertainty, especially when relatively broad escalation indices are applied. In order to confirm that the escalation factors applied to the 1988 estimates are generally in line with escalation experience in the industry, the escalation applied by Nalcor to obtain 2010$ direct cost inputs for the Strategist model was compared with:

- The Nalcor escalation factors for the Muskrat Falls project as presented in Exhibit 3 were used for the period from 2000 to 2010.
- As Exhibit 3 did not contain data for periods prior to 2000, actual industry escalation data compiled by Manitoba Hydro was used for the period from 1988 to 1999.

Application of the above escalation factors to the July 1988 capital cost estimates in Exhibit 5d (II) yielded a total 2010 capital cost that was within 2.4% of the Strategist input of $142 million. This indicates that the escalation applied to the cost estimates for the Strategist input is in line with general industry experience.

9.2.9 Other Inputs to the System Planning Process

The feasibility study, Exhibit 5d, indicates that the rated capacity of Round Pond would be 18 MW. This corresponds to the Strategist input indicated in Exhibit 14 for the Isolated Island Option.

Exhibit 12 indicates that a forced outage rate of 0.90% was used for all new hydro developments in the Strategist inputs. This rate is based on the average reported forced outage rate for Newfoundland and Labrador Hydro units for the five year period prior to 2006.

An outage rate of 0.90% is somewhat lower than the average rate for units of comparable size operated by members of the CEA for the five year period prior to 2006. Outage rates do vary significantly amongst operators of hydroelectric plants due to a number of factors including maintenance practices, control and protection schemes, size and design of units and site specific conditions amongst others. There is no obvious reason that maintenance practices for Round Pond should be different than for other hydroelectric plants in the NLH system. Of perhaps more significance is the fact that the 18 MW Round Pond unit would be much smaller than the majority of NFL's hydro units. Smaller units tend to have higher outage rates. For example, for units of 5 to 23 MW the 2006 CEA report indicates a Derating Adjusted Forced Outage Rate (DAFOR) of 3.19% versus 1.54% for units in the range 24 to 99 MW. Use of a 0.90% outage rate for Round Pond could prove to be somewhat optimistic. A higher outage rate would tend to reduce energy generation and thus the benefits associated with the project.

9.3 Portland Creek Development

9.3.1 Project Background

The proposed Portland Creek development is a 23 MW hydroelectric project that would be constructed in the northwestern part of Newfoundland in conjunction with both the Isolated Island and the Island Interconnected Options. The on-line dates set out in the generation expansion plan are 2018 for the Isolated Island Option and 2036 for the Infeed Option.

Since the Portland Creek project costs are included in the CPW calculation for both generation expansion options, the impact of changes in the projected cost for Portland Creek will, except for the secondary effect of differences in timing of the project, impact both options equally. Accordingly, the review of Portland Creek focussed on identification of factors that could have a very large impact on costs or energy production.

The Portland Creek development was the subject of a pre-feasibility study in 1987 and a feasibility study that was completed in 2007[199] . The only other reported investigation was a 2004 pre-feasibility study conducted as a student study project.

9.3.2 Basis for Review

The primary considerations for determination of the CPW contribution for the Portland Creek project are the capital costs, the operating and maintenance costs and the expected energy production and project capacity. Since operating and maintenance costs for hydroelectric projects are relatively low and predictable at the planning stage, the greatest uncertainty typically lies in the capital costs and expected energy production. These issues were therefore the focus of MHI's review.

MHI's review of Portland Creek focussed on Exhibit 5c, which includes the text of the 2007 report entitled "Feasibility Studies for Portland Creek Hydroelectric Project", and Exhibit CE-58 which includes Appendix A, Capital Cost Estimate, from the 2007 feasibility study report. The work leading to the 2007 report included a review of the previous studies conducted in 1987. Both the 1987 and 2007 studies were carried out by a consulting firm with a credible history in engineering for hydroelectric projects.

The scope of the consultant's work for the 2007 feasibility study, when considered in conjunction with the scope of work to be undertaken by the owner, is typical of the scope for a feasibility study with the following exceptions:

[199] Exhibit 5c, SNC Lavalin, "Feasibility Study for Portland Creek Hydroelectric Project", January 2007

- The scope included essentially no environmental investigations to support the expected schedule for regulatory approvals or the potential costs for mitigation, such as fish habitat.
- There was no geotechnical drilling done on site to confirm the existing sub terrain for concrete work.

9.3.3 Project Description and Background

The Portland Creek hydroelectric project site is located on Main Port Creek, a tributary of Portland Creek on the west side of the Great Northern Peninsula of Newfoundland. The project would involve the creation of a diversion pond on Portland Creek by the construction of a 110 m long, 12 m high concrete gravity diversion dam and overflow spillway. Flow would be diverted from the diversion pond to a main storage reservoir through a 320 m long diversion canal. The diversion pond overflow spillway would return excess flow to Portland Creek.

A 45 m long, 16 m high storage dam would regulate outflow from the diversion pond to the headpond which would be created by a 143 m long, 15 m high headpond dam. The headpond dam would include an overflow spillway and a power intake structure leading to a 2,900 m long penstock to the powerhouse.

The powerhouse would be equipped with two Pelton turbine generator units utilizing a net head of about 39.5 m to produce 23 MW. Access to the site would be via about 27 km of new or improved roads and the project would be connected to the grid via a 27 km long, three phase, 66 kV transmission line.

9.3.4 Level of Site Investigations

Topography

Topographical mapping with contours at 2 metre intervals for key areas of the project was developed from aerial photography. Ground survey was used to establish control points at several locations. Ground topographical surveys were also carried out for each of the major structures and incorporated into the contour mapping.

Subsurface Conditions

Subsurface conditions frequently represent one of the major areas of uncertainty and risk for hydroelectric developments. The proposed subsurface drilling program was deleted from the scope of work for the Portland Creek feasibility studies. Field investigations included a geological assessment and probing or test pitting to determine the depth of bog or overburden. Overburden is thin or intermittent in the areas of most of the major structures with significant areas of exposed bedrock outcrops. Based on the geological assessment, the consultant judged the dam foundations to be suitable for founding concrete dams. The area of greatest uncertainty would appear to be the foundations for the powerhouse and the lower portion of the penstock where there is a greater depth of overburden and the depth to bedrock is not accurately known.

Construction Materials

Tentative sources of construction materials were identified but not investigated in detail to confirm suitability for concrete aggregate.

Environmental

Based on the 2007 report, it is understood that environmental investigations had not been initiated at the time of reporting. An allowance was made for replacing altered, disturbed or destroyed fish habitat. There is no discussion of other environmental considerations and no specific allowances for environmental mitigation. The absence of environmental investigations represents a greater level of uncertainty than would be typical for feasibility level studies based on current practice.

9.3.5 Preliminary Designs

Level of Engineering

The 2007 study was identified as a feasibility level study. The original scope was reduced after award of the contract to eliminate the proposed subsurface drilling program. The lack of subsurface investigations would usually be considered a gap in the information required for a feasibility level study except in atypical cases where the subsurface conditions could be deduced from other available information. The absence of environmental investigations also represents a gap relative to current practice.

In the feasibility study report, the consultant did indicate that the level of engineering was "close to Feasibility Stage". However, the consultant concluded that, while some geotechnical data is missing, that drilling investigations would not likely produce results that would adversely affect the budget and the overall assessment of the project.

Project Arrangement

The selection of an appropriate project arrangement typically has an important impact on the technical feasibility, constructability and financial viability of a hydro-electric project. The 2007 report indicates that a number of alternative layouts were considered although the alternatives are not presented. The study does present the optimization studies that were done for project capacity as well as several of the key project components. Construction logistics including access provisions, cofferdams and de-watering were considered. The preliminary arrangements and construction sequencing are based on conventional approaches.

Each element of the proposed Portland Creek arrangement is relatively straightforward from a technical perspective. The overall project is not complex in spite of the remote locations of some of the structures required for diversion and water management.

Transmission line interconnections, substations and communications arrangements and related cost estimates were provided by Nalcor.

9.3.6 Energy Estimates

For information on capacity and energy please refer to the Hydrology Report, section 2.5.

9.3.7 Construction Schedule

The schedule presented in the 2007 report indicates a duration of 37 months from commencement of environmental approvals to first power. This schedule is based on a multi-contract design/bid/build approach that allows preparatory work such as engineering and contracting to proceed in parallel with the regulatory approvals process. The schedule allows only one year for regulatory approvals, a duration that appears to be quite optimistic unless environmental investigations have advanced since 2007. However, since the earliest online date indicated in either of the expansion plans is 2018, schedule constraints should not be an issue with respect to the development of Portland Creek.

9.3.8 Estimated Project Costs

Capital cost inputs to the Strategist model were entered in the form of direct capital costs in 2010$ and were distributed over the years in which expenditures are expected to occur in order to generate the cash flow. Escalation of the direct capital costs beyond 2010 and the AFUDC were computed within the Strategist model. The total estimated cost of the project with escalation and AFUDC was $90 million in 2010 dollars.[200]

The scope of work for the Portland Creek feasibility study included preparation of a capital cost estimate. The scope was not specific with respect to the class or level of estimate that was to be prepared.

The estimated capital cost contained in Exhibit 5c and Exhibit CE-58 is presented in December 2006 dollars.

The cost estimates are based on a fairly detailed and comprehensive breakdown of the construction quantities, equipment and facilities including construction support facilities. The estimates also include estimates of costs for management, engineering and owner's costs. Some contractor overheads such as mobilization and demobilization are not separately identified so these are assumed to be distributed amongst the unit prices for construction.

Exhibit 5c indicates only that the capital cost estimate was developed on the basis of historical prices for earthworks construction and quantities that were developed from survey information and the concept design as presented in the report. The basis for pricing of work other than earthworks was not provided. The consultant did conduct a risk analysis to assess the likely range of project costs. Based on this analysis it was concluded that there was less than a 10% probability that the final costs would vary from the estimated costs by more than about plus or minus 3%. This would suggest a very high level of confidence. However, the consultant also indicates that the level of engineering is only "…close to Feasibility Stage…".

The cost estimate was not otherwise defined in terms of industry recognized class or level designations.

[200] Nalcor's Submission to the Board of Commissioners of Public Utilities with respect to the Reference from the Lieutenant-Governor in Council on the Muskrat Falls Project, November 2011, pg. 39

In a response an RFI[201], Nalcor advises that the estimate for Island Pond is considered to be screening level or feasibility level. The estimate for Portland Creek was prepared by the same consultant using what appears to be the same methodology and in a similar time frame. The uncertainty with respect to Portland Creek would appear to be higher than for Island Pond given the lack of sub-surface investigations and the absence of even preliminary environmental investigations. Given these considerations, the levels of contingency included in the Portland Creek estimates appear to be low and there is a likelihood of an increase in project costs.

9.3.9 Other Inputs to the System Planning Process

The feasibility study indicates that the rated capacity of Portland Creek would be 23 MW. This corresponds to the Strategist Inputs indicated in Exhibit 14 for both the Isolated Island and Infeed options[202].

Exhibit 12 indicates that a forced outage rate of 0.9% was used for all new hydro developments[203]. This rate is based on the 5 year average reported forced outage rate for Newfoundland and Labrador Hydro units for the five year period prior to 2006.

An outage rate of 0.9 % is somewhat lower than the average rate for units of comparable size operated by members of the CEA for the five year period prior to 2006.

With respect to Portland Creek, there is no obvious reason that maintenance practices would be different than for other hydroelectric plants in the NLH system although the plant would be somewhat more remote. Perhaps more significance is the fact that the 11.5 MW Portland Creek units would be much smaller than the majority of NLH's hydro units. Smaller units tend to have higher outage rates. For example, for units of 5 to 23 MW the 2006 CEA report indicates a DAFOR rate of 3.19% versus 1.54% for units in the range 24 to 99 MW. Use of a 0.9% outage rate for Portland Creek could prove to be optimistic and a higher outage rate would tend to reduce the energy production and thus the benefits associated with the project.

[201] Response to RFI MHI-Nalcor-34
[202] Exhibit 14 Rev.1, Nalcor, "2010 PLF Strategist Generation Expansion Plans"
[203] Exhibit 12, Nalcor, "Forced Outage Rates Summary Sheet", June 2011

9.4 Conclusions and Key Findings

The three small hydroelectric generation projects of Round Pond, Portland Creek, and Island Pond are part of the Isolated Island Option generation resource plan. For the Infeed Option, only Portland Creek is specified with an in-service date of 2036. Each of the plants has been the subject of one or more studies which were conducted by consulting engineering firms with extensive experience in the engineering of hydroelectric projects.

Key findings from the small hydroelectric plant reviews are as follows:

- A review of the capital cost estimates for the three small hydroelectric plants indicated that the level of engineering and investigations were consistent with a feasibility level study. Considering the age of some of the studies, the review also indicated that the development schedules and cost estimates used as inputs to Strategist for the three projects were optimistic due to more stringent current regulatory processes.
- It is expected that resolution of these uncertainties would generally result in increases rather than decreases in the CPW of the three projects. However, the magnitude of any changes would not be expected to significantly alter the difference in CPW between the Isolated Island and Infeed Options.

10 Thermal Generation

Report by: B. Dandenault
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10.1 Introduction

Thermal generation is one of the key sources of energy production on the Island at present. As load grows, additional thermal generation sources are being considered to meet this demand, for base load in the Isolated Island Option and for peaking in both the Isolated Island and Infeed Options.

Within the current Isolated Island grid, Newfoundland and Labrador Hydro (NLH) operates one oil fired thermal generating station, three combustion turbines and two diesel plants. Holyrood Thermal Generating Station (HTGS) located on the south shore of Conception Bay, consists of three heavy fuel oil boilers for a combined net generating capacity of 466 MW. HTGS currently supplies approximately one third (up to 2,996 GWh annually) of the island's existing firm energy. The plant normally operates all three units during the highest customer demand periods of December through March. The plants energy production and operating factor can vary from year to year depending on the amount of hydraulic energy production, weather conditions, and industrial production requirements.

The Infeed Option includes the addition of 520 MW of thermal generation using combustion turbines (CT) and combined cycle combustion turbines (CCCT). This generation plan includes:

- Synchronous condenser conversion projects at HTGS for units 1 and 2 plus some life extension work to keep the plant running as a generation facility to 2021, after which all units operate as synchronous condensers to 2041.
- 7 – 50 MW new CTs.
- 1 – 170 MW new CCCT.

The Isolated Island Option is largely a thermal generation plan with the addition of 1,640 MW of CTs and CCCTs. The Isolated Island Option generation plan includes:

- Installation of environmental emissions controls at HTGS which includes electrostatic precipitators (ESP), flue gas desulphurization systems, also known as "scrubbers" and low NOx burners.
- Significant life extension projects at HTGS with eventual replacement of the units in 2033 and 2036 with 3 – 170 MW CCCTs.
- 9 – 50 MW new CTs.
- 7 – 170 MW new CCCTs.

The Infeed Option contains significantly less thermal generation than the Isolated Island Option.

As HTGS uses heavy fuel oil, it is a significant source of greenhouse emissions (GHGs) with the amount of emissions being proportional to energy production. Nalcor has stated that environmental stewardship is one of its guiding principles and this principle is documented within the Provincial Energy Plan (Focusing Our Energy: Newfoundland and Labrador Energy Plan)[204]. HTGS does not currently have any environmental equipment installed to control sulphur dioxide (SO_x) or particulate emissions.

Nalcor's Exhibit 16, page 27, states that "….the current Provincial Government 25,000 tons per year limitation on SO_X emissions from the HTGS, have traditionally been included in generation planning studies."[205] To date, the only year that annual emissions exceeded 25,000 tonnes was in 1989, when the SOx emissions at HTGS totaled 25,900 tonnes[206]. If 0.7% sulphur content fuel continues to be used at the facility, this target will not be exceeded in the future even with the units running at full load.

Even though Nalcor has projected a capital cost of $603 million for an environmental equipment upgrade, this investment will not reduce GHG emissions, which are expected to increase as the load factor of the plant increases. Should the GHG emission standard change through public policy to a lower target, there is the risk that a facility such as HTGS may not be able to operate in the long term. The proposed pollution control upgrades for HTGS under the Isolated Island Option meet the Newfoundland and Labrador Energy Plan's commitment to address environmental concerns at HTGS.

With pollution control equipment installed at HTGS, GHG will continue to present a challenge to its long term operation should emission standards change[207]. NLH is considering all current and impending environmental legislation in its decisions for generation expansion.

10.2 Thermal Generation Options

MHI's thermal specialists performed an assessment of the various options for HTGS and the planned CTs and CCCTs in meetings with Nalcor, with review of the available documentation, and responses to RFIs. The following outlines the various items under consideration for both generation expansion options:

Common to both options are:

- Life Extension
    - For the Infeed Option some life extension work to maintain the plant as a generating facility to 2021.
    - For the Isolated Island Option significant life extension upgrades.
- CTs
- CCCTs

Isolated Island Option:

- Installation of Pollution Control Equipment at HTGS
- HTGS Replacement in the 2033-2036 Timeframe

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204 Government of Newfoundland and Labrador, Focusing Our Energy: Newfoundland and Labrador Energy Plan, 2007
205 Exhibit 16, Nalcor, "Generation Planning Issues 2010 July Update", July 2010
206 Response to RFI PUB-Nalcor-17
207 Response to RFI PUB-Nalcor-141

Infeed Option:

- HTGS Synchronous Condenser Conversion (Units 1 and 2)
- HTGS decommissioning

10.3 Documents Reviewed

The following list outlines documents provided by Nalcor and reviewed by MHI as part of the thermal plant assessment study.

Table 22: Thermal Study Documents Reviewed

Exhibit	Title	Prepared by	Date
5	Summary – Capital Cost Estimates 2010	Nalcor	
5H	Holyrood Combined Cycle Plant Study– Final Report	Acres International	November 2001
5Li	Holyrood Thermal Generating Station Precipitator and Scrubber Installation Study	Stantec	November 2008
28	Board Letter – July 12th, 2011 Question 10 response	Nalcor	
44	Holyrood Thermal Generating Station Condition Assessment & Life Extension Study	AMEC	January 2011
65	Holyrood Marine Terminal 10 Year Life Extension Study	Hatch	April 2011
66	Newfoundland & Labrador Hydro Holyrood Generating Station, Phase 1 - Investigation of Methods to Improve Emissions on Units 1, 2 and 3	Alstom Canada	October 2002
67	Engineering Report Holyrood Generating Station MCC Assessment	Stantec	January 2009
68	Air Emissions Controls Assessment – Holyrood Thermal Generating Station Final Report	SGE Acres	February 2004
CE-39	MHI-Nalcor-1 CPWDetails	Nalcor	October 2011
CE-46 Rev. 2	PM0011 – CCGT Capital Cost Benchmark Study Final Report	Hatch	December 2008
CE-47 Rev.1 (Public)	Board Letter - July 12, 2011 Question 4b response on 50 MW Gas Turbine – Budget Estimate	Nalcor	June 2010
CE-56 Rev.1 (Public)	Feasibility Study Of HTGS Units 1&2 Conversion to Synchronous Condenser - An Evaluation of Run Up Options for Generators	SNC Lavalin	February 2011
	Board Letter – July 12th, 2011 Question 4 response	Nalcor	

10.4 Work Common to Both Generation Expansion Scenarios

10.4.1 Life Extension – Infeed Option

In the Holyrood Thermal Generating Station Condition Assessment & Life Extension Study[208] prepared by AMEC (the AMEC report), the operating basis for HTGS was noted as follows:

• 2010 to 2015 (now 2017)[209]	Continued operation as a generator
• 2017 to 2020 (now 2021)	Operation of plant in standby mode
• 2017 to 2041	Conversion of Units 1 and 2 in 2016/17 to synchronous condenser operation (Unit 3 has already been converted)

This life extension study applied only to the Infeed Option whereas the Isolated Island Option would have the plant operating as a generating facility until 2033/36.

Nalcor has investigated various options to upgrade or replace HTGS, which is approaching its end of service life. The initial screening study performed by AMEC concluded that HTGS life could be extended if capital investments were made for the refurbishment or replacement of critical plant equipment.

AMEC indicated in its report that the investigation was carried out generally in accordance with the EPRI Life Extension Condition Assessment methodology which is an industry practice for life extension for thermal plants. AMEC conducted only an initial condition assessment (Phase 1) which consisted of visual observations, interviews with operations and maintenance staff and document reviews, particularly related to previous inspection reports and plant studies.

The AMEC report covers the entire plant except for the marine terminal which is dealt with in a separate report prepared by Hatch.

The intent of the Phase 1 investigation was to assess the overall condition of the plant to provide an opinion on whether the plant is suitable for life extension based on a judgment of the remaining life of the plant and its general condition. In addition, the Phase 1 investigation developed a list of inspections and tests required to more firmly assess the condition of the main equipment, especially the boiler, steam turbine and generator, high energy piping, main step up transformer and other major equipment. The condition of plant systems, building etc. were assessed to develop a plan and timelines when upgrades and refurbishments would be required.

[208] Exhibit 44, AMEC, "Newfoundland and Labrador Hydro - Holyrood Thermal Generating Station Condition Assessment & Life Extension Study", January 2011
[209] Exhibit 14 Rev 1, Nalcor, "2010 Strategic Generation Expansion Plans"

Several concerns were noted:

- AMEC indicated that although the units are 41, 40 and 31 years of age respectively (as of 2011) the units have been operated seasonally and at light load; therefore, the operational age of the majority of equipment and systems is estimated at 20, 19 and 16 years respectively.

  This is a simplification on the part of AMEC and MHI finds that it is somewhat inaccurate as starting and stopping units and low load operation can have as much or more impact than continuous operation. Lower load operation can be more detrimental on the boiler since cooler backend temperatures occur at lower loads which increases backend corrosion. Also, systems like the main steam and hot reheat piping would have the same pressure and temperature conditions regardless of the load, resulting in the same stress and creep rate. In addition, equipment that is sitting idle or has not been properly protected during down periods may actually have just as much or possibly more life used due to corrosion.

  Nalcor currently lays up their equipment in accordance with manufacturer recommendations. They indicated that they keep the boiler and steam turbine on hot standby when not operating during weekends and drain the boiler if the plant will not operate for more than five days.

  Although there have been efforts to quantify equivalent life used when a plant is down, no definitive conclusions have been reached since this is dependent on the surrounding environment i.e. salt water marine environment or dusty environment as well as the quality of the plant lay-up are crucial.

- There does not appear to have been any benchmarking of unit life in relation to other plants with similar designed equipment. For example, in the AMEC report, Unit 1 Generator (Figure 8-2, Life Cycle Curve – Unit 1 Generator) indicates a maximum life (without life extension) of 260,000 operating hours. The associated report indicates that the “ranges of equipment life is based on current and historical information and expert opinion”. However, it does not indicate if there are similar units of a similar age that have operated without major refurbishment for up to 260,000 hours.

- The determination of remaining life of the equipment appears to be fundamentally based on operating hours and not total life. Again using the same AMEC Report Figure 8-2 the generator would be 71 years old at the end of life. When considering operating hours, there should still be an assumed upper life limit based on total installed years. It is widely accepted in industry that useable plant life is typically a maximum of 60 years including life extension work.

  Some of the conclusions for the capability of the boiler to operate until 2017 and then provide standby service in generation mode to 2021 are based on continuous use of low sulphur fuel oil (0.7%). AMEC indicated that the change to higher quality, lower sulphur fuel oil has significantly improved boiler reliability and efficiency and would have a positive impact on the life of the boiler systems. However, based on other reports, specifically the Stantec report on Electrostatic Precipitators (ESP) and Flue Gas Desulphurization (FGD), it is anticipated that HTGS may go back to higher sulphur oil, once the FGD is installed and this would have a negative impact on the life of the plant[210]. The response to RFI PUB-Nalcor 6 indicates that with the installation of pollution controls at HTGS, the use 2% sulphur fuel is acceptable for the remaining life of the plant.

However, as indicated in the AMEC life extension study, the boilers future life is significantly improved with low sulphur fuel and Nalcor staff confirmed improved boiler performance, lower maintenance requirements, and lower particulate levels of emissions using 0.7% sulphur fuel.

As indicated in the response to RFI PUB-Nalcor-17, the current Certificate of Approval for HTGS requires that the sulphur content of fuel used at the facility be no greater than 0.7% by weight.

- The number of starts can have a significant impact on unit life, especially the steam turbine, depending on the type of start i.e. cold, warm or hot and on the time taken for warm-up. The longer the start-up duration, the lower the temperature differentials and the lower the stresses incurred during start-up. However, the AMEC report only indicates the number of starts, not the type of start. This information was requested in MHI-Nalcor-108 and was subsequently provided for plant operation from 1991 to 2010. The number of starts, especially the number of cold starts is quite low alleviating this concern.

The report concluded that HTGS is a relatively modern design and in good condition employing materials and designs suitable for higher temperatures and pressures. HTGS does not appear to have any significant differences in requirements for life extension from those being faced by other utility plants of a similar vintage.

The plants' equipment was supplied by major industry vendors i.e., Babcock and Wilcox, Combustion Engineering (now Alstom), General Electric (GE), Foster Wheeler etc. Based on the investigation by AMEC, the plant appears to have been maintained well over the years with major inspections and refurbishments, when required.

During MHI's site visit, the plant was clean, appeared to be well maintained, and equipment and plant conditions were similar to those reported in the AMEC report.

The only "abnormal" condition noted was the corrosive impact of the marine environment (salt water) which would not be experienced by plants of that vintage built on fresh water lakes or rivers.

Costs

The AMEC report includes the costs for overhauls and inspections of the steam turbine, generator and boiler for Unit 1 in 2012, Unit 2 in 2014, and Unit 3 in 2016, as well as other inspections and tests for other plant components. However, it is unclear how much of the $22.58 million included in the Life Extension Study is actual life extension costs and how much is related to standard equipment overhauls i.e. the overhaul costs for the steam turbine which are incurred every 9 years and operating and maintenance costs related to keeping the plant running until 2021.

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[210] Exhibit 5Li, Stantec, "Holyrood Thermal Generating Station Precipitator and Scrubber Installation Study", November 2008

Meetings with Nalcor indicated that operating and maintenance costs planned for the plant have been considerably reduced based on the plant only operating until 2021. However, if the plant's life is extended to 2033/2036 as required by the Isolated Island Option, operating and maintenance costs would be considerably higher.

The cost carried in the Holyrood Marine Terminal 10 Year Life Extension Study prepared by Hatch was $5.5 million. Hatch indicated in its report that the cost estimates are based on similar work done in Atlantic Canada for similar generation plants and costs supplied by contractors familiar with this type of work. A more detailed study would be required in the future if Nalcor were to pursue the Isolated Island Option, as the generation equipment and marine terminal would be required to operate at least until 2036, by which time the plant would be replaced with CCCTs.

Summary and Conclusions

The AMEC report was detailed and addressed the main equipment and systems and developed a detailed list of requirements for the Phase 2 inspections and tests required and associated costs.

The AMEC Report met the study requirements documented in the report and was thorough, however, there are some issues noted:

- AMEC indicates in several locations including the Executive Summary that, although the units are 41, 40 and 31 years of age respectively (based on 2011) they have been operated seasonally and have been lightly loaded, therefore, the operational age of the majority of HTGS's equipment and systems is more like 20, 19 and 16 years respectively. This may be somewhat inaccurate as starting and stopping units and low load operation can have as much or more impact than continuous operation.
- The determination of remaining life of the equipment appears to be fundamentally based on operating hours and not total life. There does not appear to have been any benchmarking of unit life expectancy in relation to other plants with similarly designed equipment.
- Some of the conclusions for the capability of the boiler to operate until 2017 and then provide standby service to 2021 are based on using low sulphur fuel oil (0.7%). Based on other reports, specifically the Stantec report on ESPs and scrubbers, it is anticipated that HTGS may go back to higher sulphur oil once this equipment is installed. The Certificate of Approval would have to be amended by the Department of Environment and Conservation to allow the use of higher sulphur fuel.

Typically life extensions are done when the plant is approximately 30– 40 years old (end of typical original design life) and a life extension target would be to extend the plant operation for another 15 to 20 years. This would result in a total extended life of 45 to 60 years.

This would require the generator, switchgear, transformer etc. to operate for a total of 71 years (e.g. unit 1). A transformer typically has an operating life in the range of 40 years. As indicated in the AMEC report i.e. Fig. 11-7

> *"The curves indicate that the older transformers are in a critical period in their life where their reliability decreases and their likely susceptibility to system distance effects are higher. The remaining life of the transformers exceeds the end date for generation of 2020, but may not exceed the desired life of 2041 without refurbishment and replacement".*

It is likely that the transformers would not operate to 2041 without major refurbishment or replacement. This is also true of many of the components required for synchronous condenser operation as indicated in the AMEC report. It is not clear whether the costs for transformer replacements and other life extension costs are captured for the Infeed Option to maintain the plant as a synchronous condenser facility until 2041.

10.4.2 Life Extension – Isolated Island Option

In Exhibit 28, Nalcor indicated that life extension values for operation until 2033 / 2036 were included in its 2010 Capital Budget and 20 Year Plan but that, while the values in the plan are not based on detailed engineering, they do offer a conservative order of magnitude representative of the sustaining capital required for the plant.

In meetings with Nalcor, it was indicated that a cost estimate of $100 million was identified in the CPW analysis for the life extension work ($20 million per year from 2012 to 2016) and was based on comparisons with similar plants in the region, e.g. the Trenton Generating Station (Nova Scotia 1969) and the Coleson Cove Generating Station (New Brunswick 1976). MHI agrees that the $100 million estimate is conservative and appropriate for DG2.

10.4.3 Simple Cycle Combustion Turbines (CT) – 50 MW Additions

A CT consists of an air compressor, combustion chamber, turbine and generator. CTs can be operated using either natural gas or light fuel oil. Combustion turbine installations on the island system would have a nominal rating of 50 MW per unit and would be located either adjacent to existing NLH thermal operations or at greenfield sites near existing transmission system infrastructure. Due to their low efficiency, CTs are primarily deployed for system reliability and capacity support for peak demand.[211]

Combustion turbine technology is an integral part of the resource mix on the Isolated Island system today and is an appropriate supply resource for both Options.

Exhibit CE-47 Rev.1 (Public) and the response to the Board Letter July 12th, 2011 question 4 were both reviewed as part the assessment of combustion turbine simple cycle options. There was no comprehensive study report provided for the 50 MW CT.

Costs

The budget estimate for the 50 MW No. 2 oil-fired simple cycle gas turbine plant was based on an estimate documented in CE-47 Rev.1 (Public). In meetings with Nalcor, it was indicated that an additional $15 million was added by Nalcor for site preparation, fuel storage, electrical interconnection, engineering, project management etc. for a budget estimate of $55 million.[212]

[211] Nalcor's Submission to the Board of Commissioners of Public Utilities with respect to the Reference from the Lieutenant-Governor in Council on the Muskrat Falls Project, November 2011
[212] Exhibit CE-47 Rev.1 (Public), Nalcor, "50 MW Gas Turbine - Budget Estimate", July 2011

With the addition of overhead costs and contingency[213], an estimate of $65 million as shown in Exhibit 5 Summary-Capital Costs Estimates 2010 was used in the CPW analysis.

This value has then been escalated by approximately 2% per year to arrive at costs for various 50 MW installations in future years. Although the estimate was prepared based on very preliminary information, it is reasonable.

Summary and Conclusions

The estimate of $65 million assumed for a 50 MW simple cycle No. 2 oil fired CT installation is reasonable and comparable with industry estimates supplied by manufactures assuming a transmission line is in relative close proximity.

10.4.4 Combined Cycle Combustion Turbines (CCCT) – 170MW Additions

A CCCT is more efficient than a simple cycle combustion turbine. A CCCT plant is essentially an electrical power plant in which combustion turbine and steam turbine technologies are used in combination to achieve greater efficiency than would be possible independently. The higher efficiency makes it possible for CCCTs to be competitive and applicable for base load applications. CCCTs are typically configured using larger units such as the 170 MW units used in Nalcor's analysis.

The Isolated Island Option includes seven greenfield CCCT plant installations between 2022 and 2067. The CCCT Capital Cost Benchmark study prepared by Hatch in 2008 was used to develop the base cost estimate for a 170 MW greenfield installation[214]. This Benchmark Study was used to check against other studies done and to obtain an extrapolated value of the $/kW values for a 170 MW CCCT plant. The Benchmark Study report was not directly applicable to HTGS or a specific facility located in Newfoundland, but the study investigated the costs for a greenfield plant at three locations. The base cost estimate for the installations was escalated on average by approximately 2% per year to arrive at values used in the CPW analysis. MHI considers this estimate to be reasonable for the study purposes intended.

Technical Assessment

The work undertaken by Hatch was a benchmarking study. Options investigated were based on natural gas firing, local transmission and gas interconnections with wet cooling tower design. The plants also assumed that only low NOx combustors would be required with no additional Selective Catalytic Reduction (SCR) of nitrogen oxides. Although, some of these assumptions may not be suitable for a particular site in Newfoundland, the study was used as a guideline only.

The plant options considered were:

- 125 MW combined cycle plant.
- 275 MW combined cycle plant

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[213] RFI Responses – Batch 7, Nalcor, "Board Letter July 12th 2011- Question 4 response", August 2011
[214] Exhibit CE-46 Rev.2 (Public), Hatch, "PM0011 – CCGT Capital Cost Benchmark Study Final Report", December 2008

- 550 MW combined cycle plant.

These are all very typical selections of gas turbines for the size ranges investigated.

Costs

MHI reviewed the costs estimates used by Nalcor for CCCTs and found they compared well with the estimated values determined using GTPro/Peace software. This software is further described in sub-section 10.5.2.

Summary and Conclusions

The Isolated Island option includes a significant number of greenfield CCCT installations as indicated in Table 23.

Various studies and estimates, as well as the "CCGT Capital Cost Benchmark Study" report were used to come up with the base costs for a 170 MW greenfield CCCT installation. Figure 6.1 "CCGT Unit Cost to Plant Output Regressions Analysis" from the Benchmark Study was interpolated between the $/kW values determined for the various arrangements and sizes of plants reviewed in the report to provide an approximate value. The cost of $282 million in 2022 dollars for the first 170 MW CCCT plant for the Isolated Island Option is reasonable and in line with GTPro/Peace values for 2011. The base cost installation was escalated by 2% per year to arrive at values used in later years in the CPW analysis.

10.5 Isolated Island Option Thermal Plan

If the HTGS is required to continue operation past 2017, as is proposed under the Isolated Island Option, then extensive upgrades and remediation would be required. Typically a base-loaded thermal generating station has a life expectancy of approximately 30 years, but this can be extended when stations are operated continuously and are well maintained. As HTGS Units 1 and 2 are over 40 years old and Unit 3 has surpassed 30 years of service, a life extension program would be necessary to continue to operate the station safely and reliably to the end of 2033/36. Nalcor has completed Phase 1 of the condition assessment required for the life extension program, as described previously. The Phase 2 study would provide Nalcor with detailed information and costs on equipment and systems to be upgraded. After 2036 the HGTS would be replaced with CCCT technology.

Table 23: Isolated Option Thermal Plan

Isolated Island Option Thermal Plan			
Thermal Related Installations, Life Extensions & Retirements			
Year	**Description**	**Costs (millions)**	**Retirements**
2015	Holyrood ESP & Scrubbers	$582	
2016	Holyrood Life Extension (5-yr $20 M /yr)	$100	
2017	Holyrood Low NOx Burners	$20	
2019	Holyrood Upgrades	$121	
2022	170 MW CCCT (Greenfield)	$282	Hardwoods CT (50MW)
2024	50 MW CT (Greenfield) Holyrood Upgrades	$91 $9	Stephenville CT (50MW)
2027	50 MW CT (Greenfield)	$97	
2029	Holyrood Upgrades	$4	
2030	50 MW CT (Greenfield)	$103	
2033	Holyrood U1 Replacement - 170 MW CCCT Holyrood U2 Replacement - 170 MW CCCT	$465 $346	Holyrood Unit 1 (161.5 MW) Holyrood Unit 2 (161.5 MW)
2036	Holyrood U3 Replacement - 170 MW CCCT	$492	Holyrood Unit 3 (142.5 MW)
2042	50 MW CT (Greenfield)	$130	
2046	50 MW CT (Greenfield)	$141	
2049	50 MW CT (Greenfield)	$149	50 MW CT
2050	170 MW CCCT (Greenfield)	$477	
2052	170 MW CCCT (Greenfield)	$665	50 MW CT & 170 MW CCCT
2056	170 MW CCCT (Greenfield)	$534	
2063	50 MW CT (Greenfield) - 2 Units 170 MW CCCT (Greenfield)	$395 $818	2 x 170 MW CCCT
2064	50 MW CT (Greenfield)	$201	
2066	170 MW CCCT (Greenfield)	$645	170 MW CT
2067	170 MW CCCT (Greenfield)	$882	50 MW CT

Based on Exhibit 7, Service Life – Retirements and other documents, the basis for operation of HTGS for the Isolated Island Option is as follows:

Table 24: Holyrood GS operating modes and key dates for the Isolated Island Option

Isolated Island Case Operation Mode / Activity	
HTGS ESP & FGD Systems Installation	2015
HTGS Upgrade	2016
HTGS Low NOx Burner Installation	2017
HTGS Upgrade	2019
HTGS Upgrade	2024
HTGS Replacement (Units 1 &2)	2033
HTGS Unit 3	2036

10.5.1 HTGS Pollution Control Equipment Upgrades

With the Isolated Island Option, Units 1 and 2 of the HTGS would continue operating until 2033, and Unit 3 until 2036, when the station would be replaced. The station would require various upgrades to continue operating as a generating plant, where most of these upgrades involve the addition of pollution control equipment including electrostatic precipitators, scrubbers, and low NOx burners required to meet the Government's directive.

The detailed report by Stantec covering the investigation of installation of electrostatic precipitators (ESP) and flue gas desulphurization (FGD) systems at HTGS is presented in Exhibit 5-L-i.

Nalcor indicated that emission control requirements are based mainly on ground level concentrations (GLC). Currently the plant meets the GLC requirements based on monitoring results at several test locations near the facility. There is also a limit on SOx emissions of 25,000 tonnes annually, but that level does not pose any problems when using low sulphur fuel.

Nalcor also stated that an earlier study showed that the plant would not be in compliance, based on modeling, with 2% or 1% sulphur fuel. The plant would need to reduce the sulphur content in the fuel to 0.7% in order to meet GLC requirements. The plant currently operates on 0.7% sulphur fuel and emissions are well below the 25,000 tons per annum.

In Exhibit 16 - Generation Planning Issues July 2010 Update report, pg. 28, Nalcor stated that:

> *"The most prominent environmental issue currently under consideration is greenhouse gases and their impact on global warming. Carbon dioxide (CO_2) is the primary greenhouse gas of concern and Hydro's Holyrood Plant emits an average of approximately 866,000 tonnes per year of CO_2 (from footnote 6 of Exhibit 16 – Based on the 5-year average of 866,158 tonnes of CO_2 from 2005 through 2009). For example, under a cap-and-trade system, the amount of effluent, such as CO_2, Hydro could be permitted to emit could potentially be capped by a regulator at a certain level. To exceed this level, credits could perhaps be purchased from a market-based system at a price set by the market.*

> *Conversely, surplus credits for effluent not emitted under the cap level might be traded on the market to generate revenue. This type of system could have significant impacts on Hydro's production costing and the cost of electricity, especially under the Isolated Island scenario."*

CO_2 emission issues and/or costs have not been addressed in this report. Greenhouse gas emission standards are likely to be set by the Federal Government and as such pose a risk to the ongoing operation of HTGS as a generator.

Stantec selected removal efficiencies of 95% for the ESP and FGD systems. These efficiency values are considered low by industry standards but would be reasonable estimates for 2% sulfur fuel.[215]

The cost estimate in the 2008 Stantec study for the ESP and FGD systems was $450 million. In response to RFI MHI-Nalcor-101, Nalcor states that this estimate has been increased to $582 million with the additional costs attributed to corporate overheads, escalation and AFUDC. MHI finds this is a reasonable estimate to carry in the CPW analysis.

Low NOx Burners

There was no specific study provided for the addition of low NOx burners to HTGS. However, the Alstom Study on the investigation of methods to improve emissions on Units 1, 2 and 3 did investigate various potential NOx reduction technologies.[216]

The technologies investigated would be considered industry standard NOx emission reduction technologies for an oil-fired boiler and consisted of:

- burner tuning which would provide an approximate 12% reduction in NOx,
- windbox burner air modifications would provide approximately a 15 – 20% reduction in NOx,
- burner modifications plus the addition of an overfire air system that would provide 40 – 45% reduction in NOx
- and Selective Non-Catalytic Reduction (SNCR) which would provide an additional 25 – 30% reduction in NOx.

Nalcor indicated that low NOx burners have been under consideration for many years on the assumption that regulatory requirements would mandate the replacement of the present burners.

The capital cost estimate for low NOx burners outlined in Exhibit 5 is $19.8 million. The costs was prepared by Nalcor's Mechanical Engineering Department and is representative of the cost for this type of work in similar plants.

One manufacturer estimated that a low NOx burner conversion today would cost in the range of $5 to $6 million per 150 MW boiler assuming the pressure work is limited to that directly related to the

[215] Exhibit 5Li, Stantec, "Precipitator and Scrubber Installation Study Holyrood Thermal Generating Station", November 2008
[216] Exhibit 66, Alstom, "Newfoundland & Labrador Hydro Holyrood Generating Station, Phase 1 - Investigation of Methods to Improve Emissions on Units 1, 2 and 3", October 2002

burners and overfire air systems. MHI considers the $19.8 million estimate reasonable and in keeping with industry norms.

10.5.2 HTGS Replacement 2033/2036

The Holyrood Combined Cycle Plant Study report prepared by Acres International Ltd (November 2001)[217] considered two CCCT plant options located at the HTGS. The CCCT options are applicable today but the cost estimates would require updating. Three plant options were investigated in the 125 and 175 MW capacity ranges.

The technology for burning oil has not changed significantly since the study was done in 2001. The units proposed are now an older technology but are considered robust units suitable for firing oil.

The report concluded that firing on No. 6, 2% sulphur heavy fuel oil is difficult using a combustion turbine. Heavy fuel oil would be the preferred fuel since systems are in place at HTGS and heavy fuel oil is less expensive than No. 2, 0.7% sulfur oil. However, No. 6 oil tends to cause excessive erosion and corrosion of the blades. In discussions with manufacturers, both indicated that work is being done to mitigate the impacts of heavy fuel oil. From an environmental perspective, No. 2 oil would be the preferred fuel.

The report also indicated that NOx emissions could be an issue. Presently emission limits are met on CTs fired on No. 2 oil with water or steam injection. This requires a means of providing high quality demineralised water or superheated steam, increasing the cost of the CT installation significantly. Modern dry low NOx burners which do not require water or steam are not available for firing with No. 2 oil.

Costs

MHI prepared a comparison of the costs for the two options identified in the report using GTPro/Peace, a software tool used for industry benchmark cost estimating. The resultant costs for the 125 MW and 175 MW CCCTs are presented in Table 25.

[217] Exhibit 5h, Acres, "Holyrood Combined Cycle Plant Study – Combined Cycle Plant Study Update Supplementary Report - Final Report", November 2001

Table 25: Comparison of Two of the Thermal Options from the Report

Plant Size	Basis	Plant Output (MW)	Capital Cost Estimate ($millions)	Capital Cost ($ / kW)	Heat Rate (kJ/kWh) LHV[218]
125 MW	Exhibit 5H	131.2	136.4	1039.3	7528
	GTPro / Peace 2011	132.3	186.0	1407.5	7495
175 MW	Exhibit 5H	174.1	147.0	844.1	7452
	GTPro / Peace 2011	177.6	212.0	1193.8	7472

(Source: Exhibit 5H and GTPro/Peace by MHI)

GTPro / Peace is a combination of two interconnected programs, the heat balance program (GTPro) is specifically intended for the design of combustion turbine combined cycle power plants, cogeneration systems and simple cycle combustion turbine power plants. PEACE (Plant Engineering and Cost Estimator) in combination with GTPro provides engineering details and cost estimation. PEACE provides a database of installed plants and includes regional costs, provides graphic and tabular information about size, weight and cost of individual plant equipment and produces a detailed total plant cost estimate.

The values used in Exhibit 5 Summary-Capital Costs Estimates 2010 were checked against exhibit CE-46 Rev.2 (Public) CCGT Capital Cost Benchmark Study Final report Figure 6.1, "CCGT Unit Cost to Plant Output Regressions Analysis", and interpolated between the $/kW values determined in the report for an approximate value of $1,325 per kW or $225 million in 2008 dollars for a 170 MW CCGT plant.

The cost for the first unit would be higher since there would be significant costs incurred for transmission connection, fuel supply, black start capability, etc. which would not be required for the 2nd and 3rd units. The resulting base cost estimate for the first unit included in Exhibit 5 Summary-Capital Costs Estimates was $273.9 million.

The base value capital cost estimate for the second and third 170 MW units, with modifications applied for contingency and escalation was $206.2 million each. This matches up quite well to the GTPro / Peace estimate of $212 million.

The cost estimate values used in 2033 / 2036 are a combination of the $273.9 million and $206.2 million base costs escalated by approximately 2% per year. MHI finds that the values used for DG2 are reasonable.

[218] LHV is defined as Lower Heating Value and is applicable to heat rate.

Summary and Conclusions

The HTGS will require significant upgrades to continue operating as a generating plant. With the Isolated Island Option the plant would need to continue operating until 2033 for Units 1 and 2, and 2036 for Unit 3 when the plant would be replaced.

To provide a more accurate opinion on whether the generating plant could operate until 2036, the following would need to be addressed:

- What capacity will be required from the plant, and at what levels of availability and reliability?
- How long might the plant be down and what is the method / process for long term and short term layups that would be applied?

Also, the end of life would need to be defined. End-of-life may be the point at which damage has accumulated to the point where failures occur, or when the cost of inspection and repair exceed replacement cost. End-of-life may also be the point where the risk of failure is unacceptable due to hazards to plant personnel.

Smaller boiler plants have operated in many cases, in excess of 50 to 60 years; however, smaller boilers typically have much lower steam pressures and temperatures, lower heat flux rates etc. and the components are easier to replace. The end of life of these boilers typically occur when the drum's life is used up, repairs become too expensive, and emission control requirements are too restrictive.

In larger utility boilers it is unusual to find units that have been operating for more than 50 years even with life extension. Drums and other components are affected by corrosion and fatigue from flexing of the drums accumulates to the point where not only the boiler tubes require widespread replacement but so do major components. Note that even a small annual corrosion rate adds up to excessive wall and drum thinning over the years. The same is true for the steam turbine casing and other major pressure components.

Even with life extension, operation of the plant beyond 50 years, to a maximum of possibly 60 years, with reduced reliability, may not be practical. There may come a point well before 2036 when the plant becomes unsafe and unreliable to operate, not only for major components like the steam turbine rotor, boiler drum and critical piping, but also for other items such as wiring and non-critical piping.

The Holyrood replacement is anticipated to consist of 3 – 170 MW No. 2 oil-fired combined cycle combustion turbines installed in 2033 for Units 1 and 2 and 2036 for Unit 3.

The technology and the costs for the replacement plant appears to be reasonable.

10.6 Infeed Option Thermal Plan

Under the Infeed Island Option HTGS would be required to operate as is until at least 2016 then maintained in standby mode for power generation from 2017 to 2021. HTGS would primarily be operated in synchronous condenser mode from 2017 onwards. The schedule and costs for the thermal capital works and retirements are outlined in Table 26.

Table 26: Infeed Option Thermal Plan

Infeed Option Thermal Plan			
Thermal Related Installations, Life Extensions & Retirements			
Year	**Description**	**Costs (millions)**	**Retirements**
2014	50 MW CT	$75	
2017	Holyrood Units 1 & 2 Synchronous Condenser Conversion	$3	
2021	Holyrood decommissioning begins	$15	Holyrood Unit 1 (161.5 MW) Holyrood Unit 2 (161.5 MW) Holyrood Unit 3 (142.5 MW)
2022			Hardwoods CT (50 MW)
2024			Stephenville CT (50 MW)
2025			
2029	Holyrood decommissioning complete	$12	
2037	170 MW CCCT (Greenfield)	$373	
2039			50 MW CT
2046	50 MW CT (Greenfield)	$141	
2050	50 MW CT (Greenfield)	$152	
2054	50 MW CT (Greenfield)	$165	
2058	50 MW CT (Greenfield)	$179	
2063	50 MW CT (Greenfield)	$197	
2066	50 MW CT (Greenfield)	$209	
2067			170 MW CCCT

10.6.1 HTGS Synchronous Condenser Conversion

Synchronous Condenser Conversion

The SNC Lavalin Feasibility Study for Units 1 and 2 conversions to synchronous condenser operation covers the main aspects of the required electronics, controls, and generator and steam turbine modifications required to allow operation of the generators as synchronous condensers[219]. Unit 3 already has the capability to operate as a synchronous condenser and therefore, conversion is not required.

[219] Exhibit CE-56 Rev.1 (Public), SNC Lavalin, "Feasibility Study Of HTGS Units 1&2 Conversion to Synchronous Condenser - An Evaluation of Run Up Options for Generators", February 2011

SNC reviewed the various options available and recommended Static Frequency Converter (SFC) technology to be used for the conversion based on various factors including space availability, reliability, costs etc. The SFC is used to run the generation up to speed before connection to the grid.

The study only addresses the issues and costs directly related to the conversion to synchronous condenser operation and has not addressed a condition assessment of the generators, main step-up transformers, switchgear etc.

Costs

Costs for the synchronous condenser conversion were included in Exhibit 5 Summary-Capital Costs Estimates 2010 as $3.14 million with the work being done in 2016 and 2017. During the site visit on August 19, 2011 Nalcor did indicate that the SNC Study may have been too restrictive and only investigated the costs directly related to the synchronous conversion itself and did not appear to cover other costs such as building heating, cooling water modifications, etc. Therefore, a higher value, possibly in the $6.5 million – $7.0 million range could be expected for the synchronous conversion work.

Summary and Conclusion

The synchronous condenser feasibility study by SNC Lavalin was of sufficient depth to provide reasonable cost estimates for planning purposes. It is MHI's opinion that HTGS should be able to operate until 2041 as a synchronous condenser facility but reliability will likely degrade as the plant gets closer to end-of-life.

10.6.2 HTGS Decommissioning

Additional information was provided by Nalcor related to the development of the decommissioning costs of the HTGS (Responses to RFIs MHI-Nalcor-105 and 106).

In the absence of an in-depth study, Nalcor used engineering judgment to formulate the decommissioning program. This program was included in NLH's 2010 Capital Budget and 20 Year Plan as indicated in Exhibit 5 Summary Capital Cost Estimates 2010.

Costs

Details for the costs related to the decommissioning of HTGS were provided in response to MHI-Nalcor-105 and are summarized in the tables below.

Table 27: Holyrood Decommissioning Cost Estimates

Holyrood GS DCL1 Program		
Decommissioning Step	Year	Cost (1000's)
Remove and Decommission Common Electrical and Mechanical Equipment	2021	$ 1,242
Removal of Redundant Equipment (Boiler, Turbine, Stack, Auxiliaries) Unit 1	2023	$2,555
Removal of Redundant Equipment (Boiler, Turbine, Stack, Auxiliaries) Unit 2	2023	$2,555
Removal of Redundant Equipment (Boiler, Turbine, Stack, Auxiliaries) Unit 3	2023	$2,555
Remove Fuel Storage Tanks	2025	$3,868
Remove Boiler House Building	2025	$2,678
Total DCL1 Costs		$15,452
Holyrood GS DCL2 Program		
Decommissioning Step	Year	Cost
Remove Boiler House Building	2027	$5,405
Secure Land Fill and Soil Remediation	2028	$4,308
Remove Marine Terminal	2029	$2,165
Total DCL2 Costs		$11,879

(Source: Response to RFI MHI-Nalcor-105)

The total cost for decommissioning HTGS is $27.33 million. MHI finds this estimate reasonable.

A report prepared by Stantec Consulting Ltd., Thermal Generating Station and Gas Turbine Site Remediation Study, available from the Nova Scotia Power website Appendix C includes fairly detailed cost estimates for site remediation for the following plants:

- Lingan Thermal G.S.
- Point Aconi Thermal G.S.
- Point Tupper Thermal G.S.
- Trenton Thermal G.S.
- Tuft's Cove Thermal G.S.

Although the report is not directly applicable to HTGS, it does provide estimates in 2010$ for site remediation of various thermal power plants with estimates ranging from $12.3 million to $25.3 million. The overall value estimated by Nalcor is in a similar range to the values from the Stantec report and is considered to be reasonable.

Nalcor indicated in the response MHI-Nalcor-106 that the costs associated with any asbestos removal have not been fully assessed within the context of site remediation. However, virtually all the asbestos at HTGS was removed during the 2005-2007 asbestos removal program. The relatively low amount remaining is being managed through the Holyrood Asbestos Management Plan (AMP).

The "Site Decommissioning and Restoration Plan" for HTGS is covered under Nalcor's Certificate of Approval issued by the Government of Newfoundland and states that "A plan to restore areas disturbed by the operation shall be submitted to the Director for review at least ten (10) months before the time that closure of the Thermal Generating Station is determined".

Appendix B of the Certificate of Approval "Industrial Site Decommissioning and Restoration Plan Guidelines" lists several objectives / requirements for the restoration.

It was noted, in the response to RFI MHI-Nalcor-106, that Nalcor would still be using the HTGS site for synchronous condenser operation until 2041, thus the site as a whole would not need to be remediated.

10.7 Conclusions and Key Findings

The costs associated with various thermal options have been estimated for the purposes of a DG2 screening study between the Isolated Island Option and the Infeed Option.

Key findings of MHI's review of thermal projects for both options are as follows:

- The thermal studies related solely to the Isolated Island Option were screening level studies, while there was a great deal more depth to studies of the Infeed Option. The level of detail of studies on upgrading the Holyrood Thermal Generating Station was found to be adequate, and the related upgrade costs are reasonable and in line with industry standards.
- Although the Holyrood Thermal Generating Station life extension costs for the Isolated Island Option are not based on detailed engineering studies, the estimates in the cumulative present worth analysis are conservative and representative of similar plants. This expenditure is needed to extend the life of the plant as a generating facility to 2033 for units 1 and 2, and 2036 for unit 3.
- Even with life extension under the Isolated Island Option, operating Holyrood Thermal Generating Station beyond 50 years, to a maximum of 60 years, with reduced reliability, may not be practical. There may come a point well before 2041 when the plant becomes unreliable to operate.[220] The life extension plan and requirements under the Infeed Option are as follows:
    - 2010 to 2017 Electricity Generation
    - 2017 to 2021 Electricity Generation, as-required primarily on a standby basis
    - 2017 to 2041 Synchronous Condenser Operation – Units 1 and 2 converted to synchronous condenser mode by 2017. Unit 3 is already synchronous condenser capable.

- The technology and base costs assumed for the 50 MW combustion turbine (CT) and the 170 MW combined cycle combustion turbine (CCCT) installations are reasonable. The technology and costs assumed for replacing Holyrood Thermal Generating Station using CCCTs under the

[220] Exhibit 44, AMEC, "Holyrood Thermal Generating Station Condition Assessment & Life Extension Study", January 2011.

Isolated Island Option are reasonable based on present utility plant retirements for plants built in the late 1960's and early 1970's.

- A detailed site assessment study for decommissioning the Holyrood Thermal Generating Station has not yet been completed by Nalcor. The costs of decommissioning the station are high level estimates, but they are considered reasonable when compared to similar recent projects.

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11 Wind Farms

Report by: B. Buschau
K. Ooi

In the Isolated Island Option, a new 25 MW wind farm is proposed and scheduled for in-service in 2014. This is in addition to those already in operation at St. Lawrence and Fermeuse rated at 27 MW each. The latter two wind farms have a twenty (20) year Power Purchase Agreement (PPA) with NLH which expire in 2028. Once the contract period ends, there is a build-own-operate-transfer (BOOT) clause that allows transfer of ownership of the wind farm assets to NLH at no cost.[221] For the CPW calculation, it is assumed that the wind farms have a twenty (20) year operating life[222], and after this period, the entire wind farm would be replaced by NLH. The replacement cost for each of the wind farms is factored into the CPW calculation.

11.1 Scope of Review

The scope of review for wind farms included the following objectives:

- Assess related planning and cost estimates for the wind farms and verify the estimates are reasonable.
- Examine related studies or assumptions such as wind surveys, annual capacity factors and assessment of allowable non-dispatchable wind capacity in the island grid.

The review is not intended to be exhaustive but is required to be sufficient to ensure that due diligence has been performed for the wind assessment.

11.2 Costs Estimate

The existing price structure used in the evaluation is based on NLH's current wind PPA structure as outlined in Exhibit 25[223]. The annual capacity factor at 40% is assumed for the new 25 MW wind farm to be erected in 2014 and is based on the average capacity factor between the two existing wind farms at Fermeuse (44.3% capacity factor) and St. Lawrence (35.7% capacity factor). There is no specific site and wind survey data collected for the proposed new wind farm to validate the 40% annual capacity factor. According to Nalcor, the proposed site for the new 25 MW wind farm would be selected through a wind RFP process.[224] Nalcor added that from previous 2005 and 2006 wind RFPs, submissions from other proponents (excluding Fermeuse and St. Lawrence wind proponents) the

[221] Exhibit 6a, Nalcor, "PPA Listing and Rates", July 2011
[222] Exhibit 7, Nalcor, "Service Life-Retirements", July 2011
[223] Exhibit 25, Nalcor, "Board Letter July 12th 2011: A report on the information and data collected for wind farms", July 2011
[224] Response to RFI MHI-Nalcor-87

indicated expected net annual capacity factors ranging from 35% to 43%. In our opinion, it appears to be a reasonable assumption that a 40% annual capacity factor be used for a planning level estimate.

The project cost to replace the new 25 MW wind farm and full replacement of existing Fermeuse and St. Lawrence wind farms after the end of their operating life is derived as shown in Exhibit 25. There are no detailed breakdown costs for material and labor for the wind turbines and the balance-of-plant. The Nalcor cost estimates for these wind farms are based on the 2007 Ontario Power Authority Integrated System Plan EB-2007-0707, Exhibit D, Tab 5 Schedule 1, Page 25, Table 14. The table gave a general capital cost per kW for the installed capacity, which excludes the transmission cost, the cost to develop the wind farm site and the operation and maintenance cost. Escalation and a percentage of the network and transmission cost is added to the general capital cost to bring the cost estimate in line to the base year (2010) at $2,323 per kW.

The calculated O&M cost is based on the annual energy production (i.e. the annual capacity factor) for each wind farm. The price per MWh used is perhaps on the low range for calculation of the CPW based on Nalcor's wind RFP information in comparison with the O&M cost presented in Table 14[225]. On a conservative side, a higher O&M cost would reflect various unknowns such as the wind farm site, wind turbine type and maintenance schedule, service centre location, land lease, insurance etc.

The capital and O&M cost estimate presented by Nalcor are in line with the average project installed cost as outlined in the International Energy Agency (IEA) Wind 2010 Annual Report[226]. This report provides an information update on wind related issues and projects across member countries (Canada is a member). In the report, the average installed cost per kW for a wind farm in Canada for the year 2010, range from $1,999-$2,499 per kW and the O&M cost is between $14.40 to $18.00 per MWh. As a reference project for comparison of total installed cost per kW, the IEA report stated that the recently commissioned St. Joseph wind farm in Manitoba, with an installed capacity of 138 MW, had an estimated total project cost of $345 million. This translates to an average installed cost of $2,500 per kW.

The cost estimates to replace the Fermeuse, St. Lawrence wind farms and add the new 25 MW 2014 wind farm were calculated by MHI based on Nalcor's Exhibit 25: Capital Cost @ $2,323 per kW (2010 $). These estimates are shown in Table 28.

Table 28: Wind Farm Capital and O&M Requirements

Plant	Capacity (MW)	Firm Energy (GWh)	Capital Cost (2010$ M)	Annual O&M (2010$ M)
Fermeuse	27	84	$ 62.72	$ 1.28
St. Lawrence	27	105	$ 62.72	$ 1.40
New Wind Farm	25	88	$ 58.10	$ 1.30
Total	**79**			

[225] Exhibit 25, Nalcor,"Board Letter July 12th 2011: A report on the information and data collected for wind farms", July 2011
[226] IEA Wind 2010 Annual Report, July 2011

11.3 Assessment of Non-Dispatchable Capacity

A review was performed to assess the additional amount of non-dispatchable (i.e. wind power) energy that could be integrated into the island grid to further offset the fuel cost and reduce emissions at Holyrood Thermal Generating Station. In 2004, Nalcor performed an assessment of the limitations for non-dispatchable generation[227] on the island grid in an effort to identify the upper limits of wind penetration into their system.

From the analysis Nalcor performed in 2004, the upper limit of 80MW is recommended by Nalcor for wind generation due to the following constraints:

1. Water Management: Additional wind generation would cause less generation from hydro facilities and therefore more water would be spilled from reservoirs. For example, adding 20 MW to the upper limit of 80 MW, the amount of spillage would double from 9 GWh to 19 GWh on an annual basis.
2. Transmission grid security: Non-dispatchable generation could displace the demand from the hydro generation and cause the transmission network to be lightly loaded in certain areas resulting in an overvoltage condition. A small disruption to the system could cause widespread system disturbances.
3. Regional transmission issue: A possible overvoltage condition due to limited voltage control provided by wind generation.

These limits identified in the 2004 study are still applicable today as the power system has not substantially changed[228]. As load grows, the Isolated Island system should be able to accommodate additional wind generation. In the response to RFI MHI-Nalcor-89, Nalcor states that the system could accommodate an additional 100 MW of wind in the 2025 timeframe and a further 100 MW around 2035. Nalcor has not studied this in detail but will undertake studies prior to DG3.

Nalcor has also stated that it has,

> *"not completed an analysis to establish the level of wind generation that could be sustained in the Muskrat Falls LIL HVdc option. However, given that this option will include at least one interconnection to the North American electrical grid and that there will be considerable hydroelectric capacity both in Labrador and on the Island to provide backup it would not be unreasonable to consider an additional 400 MW of wind generation on the Island. Nalcor will be analysing this as part of the analysis that will be completed prior to DG3."*

[227] Exhibit 61, Nalcor, "An Assessment of Limitations for Non-Dispatchable Generation on the Newfoundland Island System, Newfoundland Hydro, System Planning & System Operations", September 2011
[228] Response to RFI MHI-Nalcor-89

11.4 Conclusions and Key Findings

MHI's review of the wind farms focused on the planning and cost estimates for the Fermeuse and the St. Lawrence wind farms, and the proposed new wind farm to verify whether or not the estimates are reasonable. MHI examined the related studies and assumptions such as annual capacity factor, cost benchmark data, and assessment of allowable non-dispatchable wind capacity in the island grid.

MHI has determined the following key finding:

- The capacity factor of 40% used by Nalcor is reasonable for a planning study. The estimated capital and operating costs used in the analysis are appropriate. Nalcor's assessment of an 80 MW limit for wind generation under the Isolated Island Option is reasonable. Additional wind power could be installed beginning in the 2025 timeframe as the system capacity grows.

12 Cumulative Present Worth Analysis

Report by: M. Kast, CA
R. Horocholyn

12.1 CPW Approach

The Reference Question asks which of the Infeed or Isolated Island Options is the least cost of the two Options excluding consideration of the monetization of the excess power from the Muskrat Falls generating facility.

The metric of least cost is not defined in the Reference Question, but the analysis provided by Nalcor uses a Cumulative Present Worth (CPW) methodology. This approach focuses on incremental capital expenditures, fuel costs, power purchase costs, and operating expenses as related to each of the two Options. The CPW approach does not take cash in-flows related to revenues into account. Present Worth Analysis is generally accepted as a methodology for comparing mutually exclusive alternatives, as long as there is a fixed output or an objective that is common to both alternatives. In this case, the fixed objective is to meet the projected load forecast, assuming the same level of service and reliability targets for each of the two Options. The goal of the least-cost analysis is therefore to choose the Option which minimizes the present worth of costs.

Equivalent costs common to both options cancel out and therefore have not been taken into account. Examples of these costs are fixed administrative expenses, and operating and maintenance costs for existing generation plants that are unaffected by the choice of either Option.

12.2 Alternatives to CPW

Other types of analysis that are commonly used for determining the preferred option from a set of alternatives include Net Present Value (NPV) and Internal Rate of Return (IRR). Both of these methods require an estimate of the revenue stream generated by the power tariffs over the forecast period, as they weigh future cash in-flows related to revenue against cash out-flows, such as those associated with capital investment. These approaches rely on discounting future cash flows to the present and the result with the highest NPV is the preferred option. Differences in risk exposure are typically manifested in the choice of discount rate. MHI is satisfied that the CPW approach used by Nalcor is reasonable for the purpose intended, being to identify the least cost choice between the two Options.

12.3 PPA versus COS Approach

Nalcor used a Power Purchase Agreement (PPA) approach related to the capital assets and operating costs for the Muskrat Falls generating facility and a Cost of Service (COS) approach for all other asset additions and expenditures, irrespective of the Option.

The Muskrat Falls generating facility will be developed and owned by Nalcor. From the perspective of NLH, for purposes of this exercise, Nalcor is considered to be an Independent Power Producer who will contract with NLH to sell energy to the utility under a Power Purchase Agreement (PPA). The tariff formula defined by the PPA will result in a per-unit charge for energy from Nalcor, which will be treated by NLH no differently than power purchased from any other non-utility generator.

Even though essentially all of the capital expenditures related to Muskrat Falls will be expended by the in-service date of 2017, with the PPA approach the costs associated with Muskrat Falls are spread out over the 60 years (anticipated life of the asset) following the in-service date in the PPA rate that is expected to be uniform throughout the future period adjusted only for escalation.

In contrast, the capital costs associated with the Labrador-Island HVdc Link have been included in the CPW using a COS approach. Following a COS approach, the burden of the capital expenditure-related costs are greater in the earlier years and decline as the capital assets are depreciated over time.

MHI tested the outcomes for each of the two approaches and the resulting impacts on the CPW for each of the two Options. The results are set out in Table 29 below.

Table 29: CPW Sensitivity to Capital Cost Methodology

($ in Billions)	Nalcor Method (1)	COS (2)
Isolated	$8.81	$8.81
Infeed	$6.65	$6.58
CPW Gap	$2.16	$2.23

Column 1 represents the existing scenario provided by Nalcor. All expenditures have been included on a cost of service basis, excepting those related to Muskrat Falls which were included on a PPA basis.

Column 2 reflects including all assets on a cost of service basis, including the capital expenditures associated with Muskrat Falls, and AFUDC (Allowance for Funds Used During Construction) at 8% (column 1 is unchanged for the Isolated Island Option as this was already an entirely COS-based calculation).

The COS approach for the Infeed Option has a somewhat lower present value cost than shown in Column 1. Although discounting tends to shelter the growing PPA costs in Column 1, and customer costs would be higher in the near term with the COS approach, in the long term the ever-increasing PPA tariff pulls the present value of costs upwards.

In both cases the CPW for the Infeed Option is less than the Isolated Island Option, so the Infeed Option remains the lowest cost Option regardless of the costing methodology chosen. However, the PPA approach for Muskrat Falls results in a present value of approximately $70 million more than a COS approach.

Nalcor has stated that the PPA approach for Muskrat Falls costing is preferable because the PPA formula ensures that the ratepayer is not overly burdened in the earlier years by a rate shock resulting from the use of the COS methodology. The COS approach front-end loads the capital costs and spreads them over a smaller energy load that is only 40% of Muskrat Fall's firm energy in 2017.

12.4 Muskrat Falls PPA

The premise supporting the use of a PPA approach relies on the base assumption that NLH will sign a take-or-pay contract with Nalcor for the specified NLH energy purchases from Muskrat Falls that Strategist has projected. As equity owner of the Muskrat Falls project, Nalcor will eventually receive its target return on the investment over the life of the asset based on the volumes consumed.

To determine the PPA prices it was assumed that all firm output (4.5 TWh) generated by the Muskrat Falls generating facility would be sold, that the internal rate of return (IRR) would be 11.0% and equity financing would be 100%. These assumptions resulted in a price of approximately $76/MWh (2010$) escalated at 2% per year in nominal terms.

However, not all energy generated by the Muskrat Falls facility in the earlier years will be taken up by NLH. The corresponding IRR based on NLH's energy purchases is 8.4%. This was considered acceptable by Nalcor given the prospect of being able to secure financial leverage through debt financing at a lower cost to replace some portion of the equity portion assumed for the calculation and as well, the prospect of being able to sell some or all of the surplus volumes of generated power in the earlier years to third parties.[229]

12.5 Choice of Discount Rate

To convert future dollar costs to a present value, Nalcor used a discount rate that is equal to its weighted average cost of capital (WACC), based on a target 75:25 debt/equity ratio.

The cost of equity is estimated as described in the response to RFI MHI-Nalcor-32:

> *"Nalcor obtains a long term forecast of risk free Government of Canada bonds from the Conference Board of Canada and then applies the cost of equity formulation as approved by the Board for Newfoundland Power and applicable to regulated NLH at its next General Rate Application. These calculations result in a long run forecast average cost of equity of 9.94% which for analysis purposes was rounded to an even 10%."*

The cost of debt is estimated as the average rate from the Conference Board's long-term forecast of 10-year Government of Canada bonds, which is assumed to be risk-free. To this rate, Nalcor added a Province of Newfoundland and Labrador spread of 1.67% to result in an estimated 7.35% rate for the Province's cost of debt.

[229] Response to RFI MHI-Nalcor-58

The weighting of 75% debt at 7.35% plus 25% equity at 10% results in a WACC of 8.0%.

Recognizing the choice of an appropriate discount rate may impact the results of the CPW analysis if there are significant differences in both the timing and scale of cost flows, MHI reviewed varying discount rates and ascertained that the choice of discount rate within a reasonably close band does not substantially affect the CPW values. As illustrated in Table 30 below, it is necessary for the discount rate to be elevated to over 17% before the CPW results for each of the two Options approximate each other. Within a band of 2% on either side of Nalcor's WACC, the differential in the CPW continues to favour the Infeed Option.

Table 30: CPW Sensitivity to Discount Rate

Discount Rate:	6%	8% (Nalcor)	10%	17.1%
Isolated	$13.241	$8.807	$6.353	$3.025
Infeed	$9.011	$6.651	$5.248	$3.025
Gap	$4.231	$2.156	$1.102	$0

(Source: MHI derived)

MHI is satisfied that the use of the weighted average cost of capital by Nalcor as a proxy for the discount rate is acceptable for the purposes of making a determination of the comparable CPW for each of the two Options.

12.6 Time Horizon for Analysis

The time horizon for the CPW analysis period was 2010 to 2067. This time frame is considered reasonable recognizing that the Muskrat Falls generating facility and the Labrador-Island Link HVdc system are the dominant capital related investments under review. The expected life span of Muskrat Falls is estimated at 60 years while the expected life span of the Labrador-Island Link HVdc system is 50 years from the date of commissioning in 2017.

12.7 Load Forecast Used in CPW

Nalcor used a single planning load forecast (PLF) for both the Isolated Island and the Infeed Options. The PLF provided in Exhibit 1 provides the forecast for total peak load and energy requirements for the island as a whole, to be provided by NLH and other suppliers. Even though Exhibit 1 does not distinguish between these two components of the system load forecast, only NLH's share of the total load forecast is factored into the CPW analysis.

In the response to RFI PUB-Nalcor-86, Nalcor acknowledges there were previously two PLFs in the NLH 2010 Capital Budget Application, and discusses the differences in the PLF between the two Options.

Using the process described in the Addendum to Exhibit 1, NLH developed a distinct load forecast for the Infeed Option, capturing the shift in demographics and economic factors that distinguish the Infeed Option from the Isolated Option. As documented in the NLH 2009 Capital Budget Application there are some small but noticeable differences between this and the status quo load forecast. There are three general observations that can be made about these differences:

1. In the earlier years of the 10-year load forecast period, increased levels of spending for project construction in the province lead to higher gross domestic product (GDP) and demographic drivers for a load increase and the Labrador-Island Link HVdc energy consumption rises above the base forecast.
2. In the immediate years following commissioning of the Labrador-Island Link HVdc system there is a cost-of-service rate shock that causes load growth to drop below the base forecast. This rate shock results from the up-front costs of the Labrador-Island Link HVdc assets in the rate base, and price elasticity for electricity depresses load growth which puts further pressure on consumption.
3. Eventually the relatively lower power costs associated with Muskrat Falls cause load growth to begin rising above the Isolated Island PLF, which is becoming further constrained as fuel oil prices continue to increase.

Without any adjustment, the Infeed Option would result in electricity rates initially being higher than would have been the case with the Isolated Island case. However, Nalcor made a policy decision that Muskrat Falls should never create an environment where rates would be higher than staying with the status quo.[230] This policy requires Nalcor to pursue rate management options that ensure Muskrat Falls would not impose a rate shock on island customers. At this point, the details of this mitigation strategy have not been identified, but the implication for the CPW analysis is that rates will be managed in order to ensure they never exceed what would have been attained using the base load forecast. The Isolated Island load forecast is essentially a proxy for the rate management strategies that will constrain rates to the level that would have otherwise been seen. If these strategies were known at this time, re-running the load forecast models should result in a load growth profile that is close to the current base forecast, and for this reason Nalcor only uses the single Isolated Island base PLF for both Options in the CPW analysis.

12.8 Least-Cost Generation Expansion Plans

Both the Infeed and the Isolated Island Options represent the least-cost sequence of new generation capacity from the two pre-defined sets of generation options for the island of Newfoundland, using standard NLH service parameters[231] and the current load forecast for the island. The generation facilities which come on-stream for each of the two Options over the period to 2067 are itemized in the 2010 PLF Strategist Generation Expansion Plan[232]. The sequencing for the facilities was determined by Nalcor using Strategist system planning software. Each of the two Options has been

[230] Response to RFI PUB-Nalcor-87
[231] Exhibit 16, Nalcor, “Generation Planning Issues 2010 July Update”, July 2010
[232] Exhibit 14 Rev.1, Nalcor, “2010 PLF Strategist Generation Expansion Plans”

evaluated based on the defined allowable mix of generation types and sizes unique to each Option. The 'least-cost' generation expansion plan is the sequence selected by the software which results in the minimum CPW, while still meeting all required service and load/energy constraints. Environmental and social considerations are factored into this analysis as direct cost inputs. This process is described in more detail in the July 6, 2011 Nalcor filing with the Board[233].

The Isolated Island Option is essentially represented by the generation expansion plan set out in Exhibit 14 Rev.1. It is limited to generation alternatives that are available on the island.

The primary capacity for the Infeed Option is the Muskrat Falls generating facility, but is supplemented with the addition of smaller additional generation constructed on the island to meet security of supply criteria. It is noted that energy may be expected to become available from the Upper Churchill facility post-2041. The Infeed Option introduces the sourcing of energy from the Upper Churchill facility beginning in 2057. The Upper Churchill capacity has not been identified in Exhibit 14 Rev. 1 even though it begins supplying energy to island consumers once the full firm capacity of Muskrat Falls is exceeded by island demand in 2057. Nalcor has indicated that Upper Churchill power is currently treated only as a placeholder for as-yet-undetermined additional sourcing required subsequent to 2057[234].

12.8.1 Capacity Plan for the Isolated Island Option

As earlier noted, the generation expansion plan for the Isolated Island Option reflects the new capacity options available on the island. The sequence developed by Strategist[235], incorporating planned additions and retirements of capacity and associated energy balances, is set out below in Table 31. Much of the incremental capacity which is projected to be brought on-stream over the period to 2067 is thermal-based. Currently, approximately 33% of NLH electricity is thermal-based, but with the incremental thermal capacity projected, by 2067 approximately 62% of capacity will be thermal-based[236]. Apart from the projected hydraulic facilities, which include Island Pond, Portland Creek and Round Pond, and the marginal capacity supplied by wind generation, all other additional capacity will be thermal-based. Accordingly, fuel costs associated with the Isolated Island Option are significant and represent nearly 70% of its CPW. In addition the increase in reliance on thermal generation brings with it the future, and somewhat unknown, challenges of meeting or exceeding new environmental targets.

[233] Nalcor's Submission to the Board of Commissioners of Public Utilities with respect to the Reference from the Lieutenant-Governor in Council on the Muskrat Falls Project, November 2011
[234] Response to RFI PUB-Nalcor-92 Rev.1
[235] Exhibit 14 Rev.1, Nalcor, "2010 PLF Strategist Generation Expansion Plans"
[236] Derived from Exhibit 16, Nalcor, "Generation Planning Issues", July 2010 and Exhibit 14, Nalcor, "2010 PLF Strategist Generation Expansion Plans"

Table 31: Energy Balance for Isolated Island Option

	Forecast Requirement		Firm Avail.	Energy Surplus	Additions and Retirements		Addition	Retirement
Year	MW	Firm (GWh)	(GWh)	(GWh)	Addition	Retirement	(GWh)	(GWh)
2010	1,519	7,585	8,953	1,368				
2011	1,538	7,709	8,953	1,244				
2012	1,571	7,849	8,953	1,104				
2013	1,601	8,211	8,953	742				
2014	1,666	8,485	9,030	545	25 MW Wind		77.2	
2015	1,683	8,606	9,203	597	Island Pond		172.3	
2016	1,695	8,623	9,203	580				
2017	1,704	8,663	9,203	540				
2018	1,714	8,732	9,302	570	Portland Creek		99.0	
2019	1,729	8,803	9,302	499				
2020	1,744	8,869	9,410	541	Round Creek		108.0	
2021	1,757	8,965	9,410	445				
2022	1,776	9,062	10,685	1,623	170 MW CCCT	Hardwoods CT1 & CBP Co-Gen	1340.0	-65.0
2023	1,794	9,169	10,685	1,516				
2024	1,813	9,232	11,079	1,847	50 MW CT	Stephenville CT1	394.2	
2025	1,827	9,290	11,079	1,789				
2026	1,840	9,372	11,079	1,707				
2027	1,856	9,461	11,473	2,012	50 MW CT		394.2	
2028	1,872	9,543	11,473	1,930	2x27 MW Wind farms	2x27 MW Wind farms	167.0	-167.0
2029	1,888	9,623	11,473	1,850				
2030	1,903	9,701	11,867	2,166	50 MW CT		394.2	
2031	1,918	9,779	11,867	2,088				
2032	1,934	9,857	11,867	2,010				
2033	1,949	9,935	12,468	2,533	2x170 MW CCCT	Holyrood 1 & 2	2680.0	-2078.8
2034	1,964	10,014	12,468	2,454	25 MW Wind	25 MW Wind	77.2	-77.2
2035	1,978	10,084	12,468	2,384				
2036	1,992	10,154	12,891	2,737	170 MW CCCT	Holyrood 3	1340.0	-917.1
2037	2,006	10,225	12,891	2,666				
2038	2,020	10,295	12,891	2,596				
2039	2,033	10,365	12,891	2,526				
2040	2,046	10,428	12,891	2,463				
2041	2,058	10,491	12,891	2,400				
2042	2,070	10,553	13,285	2,732	50 MW CT		394.2	
2043	2,082	10,616	13,285	2,669				
2044	2,095	10,678	13,285	2,607				
2045	2,107	10,741	13,680	2,939			394.2	
2046	2,119	10,803	13,680	2,877	50 MW CT			
2047	2,132	10,866	13,680	2,814				
2048	2,144	10,928	13,680	2,752	2x27 MW Wind farms	2x27 MW Wind farms	167.0	-167.0
2049	2,156	10,991	13,680	2,689	50 MW CT	50 MW CT	394.2	-394.2
2050	2,167	11,046	15,020	3,974	170 MW CCCT		1340.0	
2051	2,178	11,100	15,020	3,920				
2052	2,188	11,155	14,625	3,470	170 MW CCCT	50 MW CT & 170 MW CCCT	1340.0	-1734.2
2053	2,199	11,210	14,625	3,415				
2054	2,210	11,264	14,625	3,361	25 MW Wind	25 MW Wind	77.2	-77.2
2055	2,220	11,319	14,231	2,912		50 MW CT		-394.2

	Forecast Requirement		Firm Avail.	Energy Surplus	Additions and Retirements		Addition	Retirement
Year	MW	Firm (GWh)	(GWh)	(GWh)	Addition	Retirement	(GWh)	(GWh)
2056	2,231	11,374	15,571	4,197	170 MW CCCT		1340.0	
2057	2,242	11,429	15,571	4,142				
2058	2,253	11,483	15,571	4,088				
2059	2,263	11,538	15,571	4,033				
2060	2,274	11,593	15,571	3,978				
2061	2,285	11,648	15,571	3,923				
2062	2,296	11,702	15,571	3,869				
2063	2,306	11,757	15,020	3,263	2x50 MW CT & 170 MW CCCT		2128.4	-2680.0
2064	2,317	11,812	15,414	3,602	50 MW CT		394.2	
2065	2,328	11,866	15,414	3,548				
2066	2,339	11,921	15,414	3,493	170 MW CCCT	170 MW CCCT	1340.0	-1340.0
2067	2,349	11,976	16,360	4,384	170 MW CCCT	50 MW CT	1340.0	-394.2

12.8.2 Capacity Plan for the Infeed Option

The generation expansion plan for the Infeed Option is accomplished primarily through the addition of Muskrat Falls hydraulic generation. The Portland Creek generation facility is scheduled to come on-stream in 2036. The existing wind farms are phased out in 2028. A limited amount of thermal capacity is added over the period to 2067 for peaking power. Holyrood thermal generation will be phased out and converted to synchronous condenser operation. In contrast to the Isolated Island Option where fuel costs represent approximately 69% of the CPW, with the Infeed Option fuel costs represent approximately 18% of CPW, and are mostly associated with the continuing reliance on thermal during the period prior to commissioning Muskrat Falls. By 2067, the generation capacity mix for the Infeed Option will be based on 65% hydroelectric and 35% thermal. Energy will normally be based on a dispatch pattern that minimizes fuel use. The sequencing developed by Strategist and the associated energy balances are set out below in Table 32.

Table 32: Energy Balance for Infeed Option

	Forecast Requirement		Firm Avail.	Energy Surplus	Additions and Retirements		Addition	Retirement
Year	MW	Firm (GWh)	(GWh)	(GWh)	Addition	Retirement	(GWh)	(GWh)
2010	1,519	7,585	8,953	1,368				
2011	1,538	7,709	8,953	1,244				
2012	1,571	7,849	8,953	1,104				
2013	1,601	8,211	8,953	742				
2014	1,666	8,485	9,347	862	50 MW CT		394.2	
2015	1,683	8,606	9,347	741				
2016	1,695	8,623	9,347	724				
2017	1,704	8,663	15,290	6,627	Muskrat Falls / HVDC Link		5943.0	
2018	1,714	8,732	15,290	6,558				
2019	1,729	8,803	15,290	6,487				
2020	1,744	8,869	15,290	6,421				
2021	1,757	8,965	12,294	3,329		Holyrood 1 ,2 & 3		-2995.9
2022	1,776	9,062	12,229	3,167		Hardwoods CT1 & CBP Co-Gen		-65.0
2023	1,794	9,169	12,229	3,060				
2024	1,813	9,232	12,229	2,997		Stephenville CT1		
2025	1,827	9,290	12,229	2,939				
2026	1,840	9,372	12,229	2,857				
2027	1,856	9,461	12,229	2,768				
2028	1,872	9,543	12,062	2,519		2x27 MW Wind farms		-167.0
2029	1,888	9,623	12,062	2,439				
2030	1,903	9,701	12,062	2,361				
2031	1,918	9,779	12,062	2,283				
2032	1,934	9,857	12,062	2,205				
2033	1,949	9,935	12,062	2,127				
2034	1,964	10,014	12,062	2,048				
2035	1,978	10,084	12,062	1,978				
2036	1,992	10,154	12,161	2,007	Portland Creek		99.0	
2037	2,006	10,225	13,501	3,276	170 MW CCCT		1340.0	
2038	2,020	10,295	13,501	3,206				
2039	2,033	10,365	13,107	2,742		50 MW CT		-394.2
2040	2,046	10,428	13,107	2,679				
2041	2,058	10,491	13,107	2,616				
2042	2,070	10,553	13,107	2,554				
2043	2,082	10,616	13,107	2,491				
2044	2,095	10,678	13,107	2,429				
2045	2,107	10,741	13,107	2,366				
2046	2,119	10,803	13,501	2,698	50 MW CT		394.2	
2047	2,132	10,866	13,501	2,635				
2048	2,144	10,928	13,501	2,573				
2049	2,156	10,991	13,501	2,510				
2050	2,167	11,046	13,896	2,850	50 MW CT		394.2	
2051	2,178	11,100	13,896	2,796				
2052	2,188	11,155	13,896	2,741				
2053	2,199	11,210	13,896	2,686				

	Forecast Requirement		Firm Avail.	Energy Surplus	Additions and Retirements		Addition	Retireme nt
Year	MW	Firm (GWh)	(GWh)	(GWh)	Addition	Retirement	(GWh)	(GWh)
2054	2,210	11,264	14,290	3,026	50 MW CT		394.2	
2055	2,220	11,319	14,290	2,971				
2056	2,231	11,374	14,290	2,916				
2057	2,242	11,429	14,290	2,861				
2058	2,253	11,483	14,684	3,201	50 MW CT		394.2	
2059	2,263	11,538	14,684	3,146				
2060	2,274	11,593	14,684	3,091				
2061	2,285	11,648	14,684	3,036				
2062	2,296	11,702	14,684	2,982				
2063	2,306	11,757	15,078	3,321	50 MW CT		394.2	
2064	2,317	11,812	15,078	3,266				
2065	2,328	11,866	15,078	3,212				
2066	2,339	11,921	15,472	3,551	50 MW CT		394.2	
2067	2,349	11,976	14,132	2,156		170 MW CCCT		-1340.0

12.9 Capital Costs

The actual cash costs for all new generation and transmission capacity investments do not flow directly into the CPW analysis at the time they are incurred. Instead as earlier noted, Muskrat Falls capital costs have been included in the CPW through a PPA tariff while the remaining costs have been included in the CPW on a COS basis.

The construction and operating costs associated with the capacity plans for each of the Options are based on estimates that were developed by different means and at different times. Considering the target level of accuracy for the DG2 threshold, Nalcor has either taken cost estimates from past engineering studies and escalated them to January 2010$, or they have re-established a recent estimate based on current costs as of January 2010$. The base dollar values for all monetary figures used in the CPW analysis are January 2010$.

Where past studies' estimates were required to be escalated to base dollars, Nalcor used data from Global Insight to compile detailed escalation data which was then applied to the base dollar cost estimates reported in the past engineering studies. In this manner, these estimates were brought to 2010$ values.

All 2010$ estimates were then escalated forward to the period when the actual costs would be incurred. Escalation rates were used rather than inflation rates because they reflect underlying economic conditions whereas inflation rates are tied to changes in the value of currency and other broader monetary impacts.

Each project's capital construction costs were cumulated and applied on the in-service dates of the generation plants, when they are producing full power. Table 33 lists the annual escalation rates applied by project type, apart from Muskrat Falls and Labrador-Island Link HVdc system, from 2010 to the year of commissioning each project. A single annual escalation rate was chosen for each project as input to Strategist, as it is only capable of using one escalation rate per project.

Table 33: Escalators used by Strategist

Type of Project	Annual Escalation Rate
Gas Turbine (GT)	2.0%
Combined Cycle Combustion Turbine (CCCT)	1.9%
Hydro	1.9%
Wind	2.0%

(Source: MHI-Nalcor-49.3)

The escalation factors for Muskrat Falls and Labrador-Island Link HVdc system were calculated using "a more sophisticated approach", as described by Nalcor in Exhibit 3 and the response to MHI-Nalcor 50. The escalation projection was performed using detailed Producer Price Index (PPI) projections by cost 'bin', as provided by Global Insight, to extrapolate the 2010$ estimate to the 2017$ commissioning date values. Evaluation of the detailed costing profiles for Muskrat Falls for example was performed in order that, for each year's cost flows in the construction project, each of the 41 escalator bins was assigned a weighting. The total weighting in each year is 100%, but the pattern of costs changes from year to year, reflecting different activities throughout the different project phases.

The calculated cumulative escalation factors for Muskrat Falls and Labrador-Island Link using the Escalation Model following this methodology are set out in Table 34 below.

Table 34: Cumulative Escalation Factors for Muskrat Falls and Labrador-Island Link HVdc

Component	2010	2011	2012	2013	2014	2015	2016	2017	2018
Muskrat Falls	1.00	1.02	1.05	1.11	1.16	1.20	1.23	1.26	1.30
Labrador-Island Transmission Link	1.00	1.02	1.04	1.08	1.12	1.16	1.20	1.24	1.29

(Source: Exhibit 3, Nalcor, "Nalcor Inflation and Escalation Forecast", January 2010)

Holyrood environmental and life-extension projects also have an escalation already built into the capital costs provided to Strategist.

In addition to base costs, contingencies, and escalation adjustments, Nalcor also provided values for AFUDC. The AFUDC is used to reflect the imputed financing cost incurred during the construction phase of a new asset, before that asset is added to the rate base and begins to generate revenues. Nalcor applied AFUDC to all projects that increase system capacity, but did not apply it to capital costs for the Holyrood related projects in either of the two Options.

Tables 35 and 36 list the base dollar costs, the related escalation amounts, and the AFUDC allowances that serve to generate the total in-service cost for each capital project in the Isolated Island and Infeed Options, respectively.

Table 35: Capital Costs for Isolated Island Option

Project	In-service year	Capital Cost ($)	Escalation ($)	AFUDC ($)	In-service Cost ($)
Island Pond	2015	166,220	15,033	17,874	199,126
HRD Envir. Upgrade	2015	581,976	0	0	581,976
HRD Life Extension	2016	100,000	0	0	100,000
Holyrood Low NOx	2017	17,500	2,317	0	19,817
Portland Creek	2018	89,909	14,998	6,034	110,941
Holyrood Misc.Cap.1	2019	105,190	15,788	0	120,978
Round Pound	2029	142,192	29,006	14,165	185,363
CCCT - 170 MW	2022	206,187	50,764	24,623	281,574
GT - 50 MW	2024	65,137	21,179	4,810	91,125
Holyrood Misc.Cap.2	2024	6,832	1,716	0	8,548
GT – 50 MW	2027	65,137	26,462	5,104	96,703
Wind - 2x27 MW	2028	125,458	54,336	9,099	188,893
Holyrood Misc.Cap.3	2029	2,550	1,127	0	3,677
GT - 50 MW	2030	65,137	32,069	5,416	102,622
CCCT – 170 MW G2	2033	206,187	109,870	30,287	346,344
CCCT - 170 MW G1	2033	273,920	144,480	46,549	464,949
Wind - 25 MW	2034	58,082	35,657	4,744	98,483
CCCT - 170 MW G1	2036	273,920	168,785	49,253	491,958
GT - 50 MW	2042	65,137	58,143	6,869	130,149
GT - 50 MW	2046	65,137	68,306	7,435	140,878
Wind - 2x27 MW	2048	125,458	141,706	13,521	280,686
GT - 50 MW	2049	65,137	76,473	7,890	149,501
CCCT - 170 MW G2	2050	206,187	229,051	41,708	476,946
CCCT - 170 MW G1	2052	273,920	324,355	66,562	664,837
Wind - 25 MW	2054	58,082	81,209	7,050	146,340
CCCT - 170 MW G2	2056	206,187	281,085	46,695	533,967
GT - 2x50 MW	2063	130,274	243,429	20,823	394,526
CCCT - 170 MW G1	2063	273,920	461,977	81,873	817, 770
GT - 50 MW	2064	65,137	125,452	10,620	201,208
CCCT - 170 MW G2	2066	206,187	281,997	56,365	644,550
CCCT - 170 MW G1	2067	273,920	519,520	88,275	881,714

It is noteworthy that Nalcor has incorporated a large investment programme in the Isolated Island Option for reducing the environmental footprint of Holyrood. The question arises as to whether or not this is necessary, as switching to 0.7% sulphur fuel oil has accomplished as much as is necessary to meet Provincial environmental targets for SO_x.

The impact on the CPW relating to the sensitivity of removing the cost of the Holyrood environmental upgrade for the Isolated Island Option was tested. If NLH did not proceed with the environmental upgrade for the Holyrood facility, the difference in the CPW between the Infeed Option and the Isolated Island Option is reduced from $2.2 billion to $1.8 billion.

Table 36: Capital Costs for Infeed Option

Project	In-service year	Capital Cost ($)	Escalation ($)	AFUDC ($)	In-service Cost ($)
50 MW CT	2014	65,137	5,672	3,945	74,755
HVDC Labrador-Island Link	2017	1,852,000	221,168	480,067	2,553,235
Sync. Condenser	2017	2,757	415	111	3,283
Holyrood Decomm. Ph.1	2025	12,000	3,452	0	15,452
Holyrood Decomm. Ph.2	2029	8,498	3,384	0	11,882
Portland Creek	2036	89,909	57,302	8,467	155,678
CCCT – 170 MW	2037	206,187	134,584	32,656	373,426
CT – 50 MW	2046	65,137	68,306	7,435	140,878
CT – 50 MW	2050	65,137	79,305	8,048	152,491
CT – 50 MW	2054	65,137	91,212	8,712	165,061
CT – 50 MW	2058	65,137	104,100	9,430	178,667
CT – 50 MW	2063	65,137	121,715	10,411	197,263
CT – 50 MW	2066	65,137	133,152	11,049	209,337

Capital costs are a significant input to the CPW analysis. The impact of changes in capital costs on the CPW results was tested. For example, if the Labrador-Island Link capital costs increase by 25%, the CPW differential in favour of the Infeed Option would be reduced by $398.0 million, and if the Muskrat Falls Generating Station capital costs increased by 25%, the CPW differential in favour of the Infeed Option would be reduced by $577.0 million[237]. If both the Labrador-Island HVdc Link and the Muskrat Falls Generating Station costs increase by 25%, the CPW differential in favour of the Infeed Option would be reduced by $975 million.[238]

12.10 Inventory

Nalcor did not include the carrying cost of fuel inventory which is normally part of the rate base component used in determining the cost of service for the utility.

In the current comparative analysis of CPWs, the value of fuel inventory would only be significantly different between the two Options in the period where Holyrood is no longer generating base load power, which exists mostly from 2017 and on. If fuel inventory carrying costs were included in the CPW analysis, the consequence would be an increase in the CPW for the Isolated Island Option, and accordingly would serve to further increase the gap between the two CPW values.

[237] Response to RFI MHI-Nalcor-41
[238] Exhibit 43 Rev.1, Nalcor, "Newfoundland and Labrador Hydro – 2010 Generation Expansion Analysis (Revision 1)"

12.11 Asset Life

The expected service life of an asset and its initial cost are the primary determinants of the annual depreciation expense and the annual regulatory return on the un-depreciated value of the investment. Nalcor has applied asset lives that are typical in the industry, as noted in Table 37 and 38 below, for each of the Isolated Island and Infeed Options respectively. All hydraulic facilities have been assigned an expected life of 60 years, while CCCT plants are 30 years, combustion turbines 25 years, and wind farms 20 years.

For Holyrood expenditures, the expected life assigned varies between scenarios. In the Isolated Island Option, investments related to Holyrood have been assigned a service life from the in-service date to the expected decommissioning date of Holyrood in 2036. In the Infeed Option, the project to convert the generators to synchronous condensers is assigned the life of its rotating machinery, and the latter decommissioning costs are amortized over 60 years. These assigned service lives are reasonable.

Table 37: Fixed Cost Parameters for Isolated Island Option

Project	In-service year	In-service Cost	Service Life (years)	Insurance Rate (%)
Island Pond	2015	199,126	60	0.100%
HRD Envir. Upg.	2015	581,976	21	0.125%
HRD Life Extension	2016	100,000	20	0.125%
Holyrood Low NOx	2017	19,817	19	0.125%
Portland Creek	2018	110,941	60	0.100%
Holyrood Misc. Cap. 1	2019	120,978	17	0.125%
Round Pond	2020	185,363	60	0.100%
CCCT - 170 MW	2022	281,574	30	0.125%
CT - 50 MW	2024	91,125	25	0.125%
Holyrood Misc.Cap.2	2024	8,548	12	0.125%
CT – 50 MW	2027	96,703	25	0.125%
Wind - 2x27 MW	2028	188,893	20	0.100%
Holyrood Misc.Cap.3	2029	3,677	7	0.125%
CT - 50 MW	2030	102,622	25	0.125%
CCCT - 170 MW G2	2033	346,344	30	0.125%
CCCT - 170 MW G1	2033	464,949	30	0.125%
Wind - 25 MW	2034	98,483	20	0.100%
CCCG - 170 MW G1	2036	491,958	30	0.125%
CT - 50 MW	2042	130,149	25	0.125%
CT - 50 MW	2046	140,878	25	0.125%
Wind - 2x27 MW	2048	280,686	20	0.100%
CT - 50 MW	2049	149,501	25	0.125%
CCCT - 170 MW G2	2050	476,946	30	0.125%
CCCT - 170 MW G1	2052	664,837	30	0.125%
Wind - 25 MW	2054	146,340	20	0.100%
CCCT - 170 MW G2	2056	533,967	30	0.125%
CT - 2x50 MW	2063	394,526	25	0.125%
CCCT - 170 MW G1	2063	817,770	30	0.125%
CT - 50 MW	2064	201,208	25	0.125%
CCCT - 170 MW G2	2066	644,550	30	0.125%
CCCT - 170 MW G1	2067	881,714	30	0.125%

Table 38: Fixed Cost Parameters for Infeed Option

Project	In-service year	In-service Cost ($)	Service Life (years)	Insurance Rate (%)
50 MW CT	2014	74,751	25	0.125%
HVDC Labrador-Island Link	2017	2,553,235	50	0.000%
Sync. Condenser	2017	3,140	60	0.125%
Holyrood Decomm. Ph.1	2025	15,451	60	0.125%
Holyrood Decomm. Ph.2	2029	11,881	60	0.125%
Portland Creek	2036	155,671	60	0.100%
CCCT – 170 MW	2037	373,411	30	0.125%
CT – 50 MW	2046	140,871	25	0.125%
CT – 50 MW	2050	152,483	25	0.125%
CT – 50 MW	2054	165,053	25	0.125%
CT – 50 MW	2058	178,658	25	0.125%
CT – 50 MW	2063	197,253	25	0.125%
CT – 50 MW	2066	209,327	25	0.125%

As a further comment with respect to asset life, the typical process for comparing alternatives requires that all options have the same lifespan so that the positive cash flows arising from the individual investments can be fully realized. Where there are differences in the asset life of investments between alternatives, adjustments can be made to compensate.

However, in the case of the current analysis, cash in-flows have been excluded from the CPW calculation. With the CPW analysis, using the COS methodology, the return on the rate base of an asset that is introduced into the generation sequence may extend beyond the end of the 2010-2067 analysis period. As a result, there will be some capacity increments whose full life-cycle benefit are not completely captured. The implications of this aberration have a more profound impact on the Isolated Island Option than the Infeed Option. Since the timeline for the analysis matches Labrador-Island Link HVdc system and approximates that of Muskrat Falls, the impact on the Infeed Option is minimal. In contrast, for the Isolated Island Option, there is a larger proportion of investment projects that are not fully depreciated by 2067. Making a compensating adjustment for this difference would likely add more costs to the Isolated Island Option, leading to an increase in the CPW differential between the two Options.

12.12 Depreciation Expense

For assets included in the analysis on a COS basis, a depreciation expense component related to each project asset is included in the CPW.

Ideally, the computation of depreciation expense should commence when the respective assets are placed into service, and the revenue generated from the use of that asset begins. Given the DG2 stage of development for each project in the analysis, Nalcor assigned a single in-service date for each identified project in the CPW analysis, even though in some instances the project asset is expected to begin generating revenue for NLH prior to the final commissioning date for the project. This potentially occurs where there is more than one generating unit in a project, such as wind farms, hydro stations, and double-unit CCCT projects.

The implication of using a single in-service date in the CPW analysis is that the work-in-process costs that are allowed to accumulate up to the final commissioning date will attract more AFUDC, and therefore make the final in-service costs somewhat higher than would be the case if there were multiple in-service dates for each generating unit. However, in the context of the CPW analysis, this is more than mitigated by the cumulative discounting of fixed costs in the final stages of the project. This is not expected to materially change the relative CPW values between the two Options.

12.13 Regulatory Return on Assets

The CPW includes a Return on Rate Base as a component of the COS. The computation of the Return component is in line with prior regulatory Orders of the Board. As noted above in section 12.5, NLH's Weighted Average Cost of Capital (WACC) is 8.0%. The rate base upon which the WACC is applied incorporates the net asset value of qualified investments that contribute to the production and sale of power to island customers. From the date each asset is commissioned, it is thereafter depreciated on a straight-line basis until the remaining book value of the asset is zero. The sum of the depreciation expense, insurance expense, and the regulatory return on rate base, which includes the net book value of the asset times the WACC, constitutes the respective "fixed cost" for each asset for purposes of computing the CPW values for each Option.

12.14 Insurance

Transmission and distribution assets are self-insured. All other property and equipment is insured on a replacement-cost basis in the general insurance market[239]. Based on discussions with Nalcor, property insurance costs included in the CPW are based on the original in-service cost, which for most types of plant amounts to $0.125 per $100 of original cost. Recognizing that the replacement cost of a current capital expenditure would be an escalated amount, one would reasonably expect that the insurance premium would also be escalated. However, the CPW assumes the insurance expense is constant until the plant is retired. Notwithstanding this point, the difference in insurance costs between fixed and escalated estimates only amounts to a discounted present value of less than $20 million, and accordingly does not have a material effect on the final CPW analysis.

[239] Response to RFI MHI-Nalcor-59

12.15 Thermal Heat Rates

The fuel costs included the CPW analysis are derived from the incremental cost for fuel consumed by thermal generation plants that are required to meet the requirements of the planned load forecast. The cost of fuel is a function of the volumes of each type of fuel consumed and the cost of fuel per unit of volume. All fuel costs included in the CPW are either #2 fuel oil for the combustion turbine units, or #6 fuel oil for HTGS.

The amount of fuel consumed is also a function of plant efficiency, which varies depending on the technology employed and plant efficiency. The term typically used for fuel efficiency is 'heat rate', which is the amount of input energy required to produce a unit of electricity. In addition, plants use some relatively small amount of electricity internally as part of normal operations, which is netted out. The specific net heat rate parameters used by Nalcor in the CPW analysis are set out below in Table 39.[240] The heat rate efficiencies are used as input to Strategist for minimum and maximum production levels, and Strategist uses this range to determine operating efficiency on an hourly basis."[241]

Table 39: Net Heat Rates for Thermal Plant

Plant Type	Fuel Type	Net Heat Rate (MBTU/kWh)
Existing CT	#2	12.263
New CT	#2	9.434
Diesel	#2	10.970
CCCT	#2	7.637 - 8.629
Holyrood	#6	9.780 - 10.388

[240] Exhibit 9 Rev.1, Nalcor, "Thermal Units - Average Heat Rates"
[241] Response to RFI MHI-Nalcor-49-1-a

12.16 Purchased Power

Another component of energy-related costs within the CPW analysis is purchased power. These sources include[242]:

- Nalcor-owned hydro-generation, including:
  - Star Lake – 15 MW / 144.5 GWh per year
  - Exploits River Partnership – 32.3 MW / 137 GWh per year
  - Exploits River generation – 58.5 MW / 479.7 GWh per year
- Non-utility generators (NUGs)
  - Corner Brook Co-generation – 15 MW / 65.3 GWh (until 2022)
  - Rattle Brook – 4 MW/14.5 GWh
- Wind-sourced power (until 2028)
  - Fermeuse – 27 MW / 84.4 GWh per year
  - St. Lawrence – 27 MW / 104.8 GWh per year
- New Wind Farm (2014) – 25 MW/87.6 GWh
- The proposed Nalcor-owned Muskrat Falls Generating Station

The PPAs for the two wind farms, Fermeuse and St. Lawrence, expire at the end-of-life for each facility in 2028. In the Isolated Island Option, these plants are assumed to be re-built by Nalcor and the capital costs of these re-builds are incorporated into the CPW analysis. In the Infeed Option, wind-sourced power is more expensive than Muskrat Falls-sourced power, and therefore the existing wind plants are decommissioned in this Option.

12.17 Operating Costs

Nalcor estimated operating costs for new generation facilities based on current NLH experience for similar types of facilities where possible. A distinction was made between fixed O&M costs and variable O&M costs for all facilities except Muskrat Falls and Labrador-Island Link HVdc system where a combined O&M amount was applied.[243] The operating costs were valued by Nalcor in 2010 base dollars, and an escalation factor was applied for future O&M costs.

During the technical review of the Infeed Option, MHI could only identify reference to a minimal amount of $2.5 million to cover the cost for operations over the entire 50-year life of the 1,100 km Labrador-Island Link HVdc system. Notwithstanding, Nalcor did incorporate in the CPW analysis a

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[242] Exhibit 6a, Nalcor, “Hydro PPA Details”, July 2011
[243] Exhibit 8, Nalcor, “Muskrat Falls HVdc Link Operating Costs Estimates”, February 2011

constant annual operating cost of $11.6 million (2010$) from 2017 to 2025, and $12.4 million (2010$) thereafter to undertake vegetation control programs. They also included a fixed $4.4 million (2010$) cost for periodic cable surveys for the Strait of Belle Isle crossing approximately every five years.

However, there does not appear to be any provision for capital maintenance of the converter transformers. In order to test the sensitivity of additional costs for this, MHI assumed the following:

- Fourteen converter transformers at $5 million each, distributed over years 20-30, leaving the Labrador-Island Link HVdc system asset fully depreciated in 2067

The effect of this is to add $7 million per year over the period from 2029 to 2038, which results in an increase in the CPW for the Infeed Option from $6.651 billion to $6.672 billion. The $70 million difference is effectively discounted to $21 million in the CPW calculation and is therefore not material to the current analysis.

With respect to operating costs, Nalcor provided cost escalation forecasts in Exhibit 3 for O&M expenses for both Options. These forecasts apply to both fixed and variable O&M costs.

The O&M cost forecast escalators are defined in terms of the balance between the composite cost of labour and materials, as described in the response to RFI MHI-Nalcor-50:

1. More material, less labour
2. Same material, same labour
3. More labour, less material
4. Labour only

Nalcor assumed an O&M cost escalation forecast of 2.5% based on the second type, "same material/ same labour" for Labrador-Island Link HVdc system and 2.8% based on the third type, "more labour/less material" for other new generation plants modeled.

12.18 Upper Churchill Power

MHI understands that the current Upper Churchill contract with Hydro Quebec expires in 2041. Nalcor had indicated that sourcing Upper Churchill power was not considered because of the uncertainty as to what will happen post-2041. However, in the document provided as response to RFI MHI-Nalcor-49.2(d), Nalcor shows a supply of energy for the Infeed case from a source labelled 'Other'. This energy provided over the Labrador-Island Link to NLH, beginning in 2058, is priced at $2 per MWh, without escalation, which is the approximate price of Upper Churchill power. The timing of the introduction for Upper Churchill energy corresponds to the point at which NLH demand grows to the level it fully consumes Muskrat Fall's average annual generating capacity.

12.19 Fuel Costs

In Exhibit 4, Nalcor provided reference fuel oil price projections[244] for #6 and #2 fuel for the period 2010 – 2025 from the PIRA Energy Group (PIRA), an energy consulting firm which provides analysis and price forecasting services for world energy prices. Nalcor escalated the price forecasts past 2025 at a rate corresponding to the 2% long-term CPI inflator. Since it is beyond a reasonable expectation for anyone to predict with accuracy to what extent fuel prices will escalate beyond 2025, MHI conducted a sensitivity analysis on the potential fluctuation of fuel costs beyond 2025.

It was determined using the original March 2010 reference prices for the various grades of fuel oil used by Nalcor in the Base Case, that changing the long-term price inflator by ±1% relative to the 2% used by Nalcor has a minimal effect as illustrated in Table 40 below. It is apparent that the CPW analysis is not particularly sensitive to the choice of the annual escalation factor applied to the base fuel prices, because the escalation is so far into the future that discounting minimizes their impact.

Table 40: Sensitivity of CPW to the Long-term fuel price inflator ($billion)

Long-term CPI	1%	2%	3%
Isolated	$8.677	$8.810	$8.962
Infeed	$6.651	$6.651	$6.651
Gap	$2.026	$2.159	$2.311

(Source: MHI derived)

What is more critical is the accuracy of the base price projections. This raises the issue of how to best incorporate such uncertainty.

PIRA generally provides four forecast scenarios for consideration by their energy clients:

- Reference price,
- Low price,
- High price, and
- Expected price.

The reference price forecast is the price for delivery at a specific location, based on a current 'reference' scenario for various world financial and economic drivers.

The high and low forecasts reflect alternate possible econometric scenarios that would lead to either higher price pressures or lower price pressures, respectively.

[244] Exhibit 4, Nalcor," NLH Thermal Fuel Oil Price Forecast Reference Forecast", January 2010

An expected price scenario is also calculated as the weighted average price forecast of the reference, low, and high cases. The expected price forecast encompasses the uncertainties associated in the other three scenarios into one.

PIRA also estimates the discrete probability of occurrence for each of the reference, high and low price forecast scenarios. The relative probabilities assigned to each scenario can vary sharply from one forecast to the next.

Nalcor used the reference price scenario in its original CPW calculation and subsequently provided corresponding CPW values in Exhibit 43 based on low and high fuel price forecasts.

The impact on the CPW of using the expected price rather than the reference price was examined. Based on the March 2010 forecast prices provided by PIRA set out on page 10 of 37 in Exhibit 43, and assumed weightings of 50%/25%/25%, the resultant expected prices are higher than the reference prices. The implication is that the CPW provided by Nalcor for the Isolated Island Option is understated. Alternatively, if one were to use a lower fuel prices forecast there is a strong possibility the expected price will be lower than the reference price, in which case the CPW for the Isolated Island Option would be reduced.

To illustrate how the CPW can change based on which scenario is used for analysis, Table 41provides CPW values based on the March 2010 reference, low, high, and expected price cases.

Table 41: CPW Sensitivity to Price Scenarios (March 2010 Forecast - $billions)

Price Case	Low	Reference	High	Expected
Isolated	$6.221	$8.810	$12.822	$9.363
Infeed	$6.100	$6.652	$7.348	$6.719
Gap	$0.120	$2.158	$5.474	$2.644

(Source: Low, Reference, High – Exhibit 43 Rev.1
Source: Expected – MHI derived)

The expected case based on the March 2010 forecast results in a slightly larger gap between the two Options, relative to that provided by Nalcor. This could however change using yet a different PIRA forecast. More interesting is the low price case, where a near-term double-dip recession in the US might lead to fuel prices that are so low that the CPW gap almost disappears.

It is clear there is much uncertainty related to the pricing of fuel for thermal-based power generation. Different scenarios can and should be run and compared, but the results related thereto often have a short shelf life. While the prospect of raising the necessary capital to finance and construct the Infeed Option may be daunting, the uncertainty associated with forecasting the price of fuel for thermal generation over the long term might be, and likely is, even more so.

12.20 HVdc System Losses

Nalcor assumed HVdc system losses are set at 5.0%. However, there is reason to believe they could be higher based on a response to RFI MHI-Nalcor-62. If the loss percentage is 10%, which is Nalcor's worst case design scenario, then there will be higher transmission losses associated with the Labrador-Island Link HVdc system when operating at capacity. An incremental increase of 5.0% to system losses may result in the addition of $150 million to the CPW costs for the Infeed Option.

12.21 Combined Input Sensitivities

Additional sensitivities were performed by varying multiple inputs. For example, if there is a 20% decrease in fuel costs, combined with a 20% decrease in the annual percentage load growth post 2014, and a 20% increase in the capital cost estimate for both Muskrat Falls Generating Station and the Labrador-Island Link HVdc system, the CPW differential would be reduced to $159 million in favour of the Infeed Option.[245]

Also, should the existing pulp and paper mill cease operations, and its generation capacity be available for use on the system (approximately 880 GWh), and should the capital costs of both the Muskrat Falls Generating Station and Labrador-Island Link HVdc projects increase by 10%, the CPW for the two Options would be approximately equal[246].

12.22 CPW Sensitivity Analysis Summary

With projects of this magnitude, and considering the 50+ year (2010 – 2067) analysis period, there are risks and uncertainties associated with the key inputs and assumptions. Changes in these key inputs and assumptions will affect the financial results and must be assessed to determine materiality. These changes in key inputs and assumptions can impact the results of the analysis and shift the preference for what is the least cost option. Fuel costs and construction material costs are variable with world economic conditions. Load forecasts are a major input based on local conditions and must be carefully monitored to ensure that generation development occurs in compliance with future load requirements.

Table 42 summarizes the results of various sensitivities. Increases in capital cost, load forecast reduction, or fuel price reduction could result in the favourable CPW differential for the Infeed Option being substantially reduced or even eliminated.

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[245] Response to RFI PUB-Nalcor-56
[246] MHI derived

Table 42: CPW Sensitivity Analysis Summary

	Sensitivity Summary	Isolated Island Option	Infeed Option	Difference
1	Base case	$8,810	$6,652	$2,158
2	Annual load decreased by 880 GWh	$6,625	$6,217	$408
3	Fuel costs: PIRA's low price forecast	$6,221	$6,100	$120
4	Fuel price reduced by 44% from base case	$6,134	$6,134	$0
5	Labrador-Island Link capital cost increased by 25%	$8,810	$7,050	$1,760
6	Muskrat Falls GS capital cost increased by 25%	$8,810	$7,229	$1,581
7	Muskrat Falls GS and Labrador-Island HVdc Link capital cost increase by 25%	$8,810	$7,627	$1,183
8	Labrador-Island HVdc Link and Muskrat Falls capital cost increased by 50%	$8,810	$8,616	$194
9	Scenario with • Fuel cost decreased 20% • Annual load growth decreased of 20% • Capital cost increased for Muskrat Falls GS and Labrador-Island HVdc Link by 20%	$7,037	$6,878	$159
10	Scenario with • Annual load decreased by 880 GWh • Muskrat falls GS and Labrador-Island HVdc Link Capital cost increased by 10%	$6,625	$6,598	$27

Sources:

Scenarios 1,2,3,4,5,6,7: Response to RFI MHI-Nalcor-41 Revision 1 and EX-43 Rev.1
Scenario 8: Response to RFI PUB-Nalcor-118
Scenario 9: Response to RFI PUB-Nalcor-56
Scenario 10: MHI derived

Given the sensitivity of the load loss on the CPW, particularly in combination with potential variations in fuel price and capital cost estimates, MHI considers it imperative that Nalcor obtain as much understanding as possible regarding the future prospects for the continued operation of its industrial customers and in addition, develop contingency plans to address the implications of reductions in industrial loads.

12.23 Conclusions and Key Findings

When analyzing the least cost as determined by Nalcor, MHI reviewed all Nalcor exhibits and RFI responses that related to the calculation of the CPW figures. In reviewing this information submitted by Nalcor, MHI assessed the specific details of the methodologies employed, both to evaluate the approach used to construct Nalcor's two Options and to look for possible mechanical or methodological errors.

The key finding from the review of the CPW analysis is as follows:

- Based on the capital and operating costs estimated by Nalcor for each option and a common load forecast, Nalcor has determined that the Infeed Option has a lower cumulative present worth than the Isolated Island Option by approximately $2.2 billion. The detailed analysis performed by MHI determined that Nalcor's cumulative present worth analysis was completed using recognized best practices and the cumulative present worth for each option was correct based on the inputs used by Nalcor. These inputs were reviewed in the technical and financial analyses conducted by MHI and were generally found to be appropriate. There are, however, other considerations related to risks associated with the assumptions used for certain key inputs such as load, fuel prices and cost estimates which may impact the cumulative present worth analysis for the two options. These were tested with the use of several sensitivity analyses and the results of these are summarized as follows:
  - Load Forecast

    A major input to the cumulative present worth analysis is the load forecast, and as a result any large changes in the load would have a significant impact. For example, should the existing pulp and paper mill cease operations, and its generation capacity be available for use on the system, and should the capital costs of both of the Muskrat Falls Generating Station and Labrador-Island Link HVdc projects increase by 10%, the cumulative present worth for the two Options would be approximately equal[247].

  - Capital Cost Estimates

    The current capital estimates are within the accuracy of an AACE Class 4 estimate which has a plus factor variance potential of as much as 50%. Should cost overruns reach that level, the difference between cumulative present worth values for each of the two Options would be less than $200 million in favour of the Infeed Option.

  - Fuel Price

    There remains significant uncertainty in fuel price forecasts. Global disruptions in supply could drive the price of oil well above inflation. However, new sources of supply, such as shale oil or downward trends in natural gas pricing, may have the potential to minimize fuel price increases.

    If fuel prices drop by 44% below those used by Nalcor, the difference between the two cumulative present worth results becomes neutral. However, if fuel prices rise more than the reference price used in the cumulative present worth analysis, an even greater difference between the cumulative present worth results would occur.

  The risks associated with these Inputs are further magnified considering the 50+ year period used in the preparation of the cumulative present worth analysis.

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[247] MHI derived from RFI MHI-Nalcor-41 Revision 1

Further considerations which cannot be overlooked relate to meeting environmental guidelines in the future which could be problematic. Nalcor stated that it may not be able to continue operating its oil fired generation facilities if a natural gas combined cycle benchmark for GHG emission intensity levels is applied to oil fired generation.[248]

It is also noted, that while no consideration has been given to carbon pricing in either option, the impact of any future value of carbon credits will be more significant on the Isolated Island Option, which will lead to increasing the differential between the two Options.

[248] Nalcor's Submission to the Board of Commissioners of Public Utilities with respect to the Reference from the Lieutenant-Governor in Council on the Muskrat Falls Project, November 2011, pg. 64

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13 Team and Qualifications

Paul Wilson, P.Eng. (MHI Project Director)

Paul Wilson has over 25 years of utility experience in Generation, Transmission, Distribution, and commercial company operations and is currently the Managing Director, Subsidiary Operations of Manitoba Hydro International Ltd. (MHI). MHI assists power utilities, governments, and private sector clients around the world in the efficient, effective, and sustainable delivery of electricity.

Paul was also the past Managing Director of the Manitoba HVDC Research Centre, which is now a division of MHI. The technical staff of the HVDC Research Centre is involved in the planning, specification, commissioning, operations and maintenance of HVDC plants operating in many countries around the world. A graduate from the University of Manitoba in 1987, in Electrical Engineering, he is an active member of Cigré, and a licensed practicing member of the Association of Professional Engineers and Geoscientists of the Provinces of Manitoba, Saskatchewan and Newfoundland and Labrador. Paul is President of the Energy Service Alliance of Manitoba, an association of energy service consultants active in both domestic and international services work.

Paul's particular experience relevant for this proposal stems from his work on the Concepts Review Panel for Potential Future Use of Underground or Under Water Cables for Long Distance Transmission in Manitoba Industry Panel. This panel examined a number of options for submarine and underground cables for ac and HVDC power transmission in Manitoba, including cost estimates, cable installation and maintenance issues, environmental issues, and system issues relevant to this study.

Allen Snyder, P.Eng. MBA (Project Manager / Team lead)

Mr. Snyder, as a Professional Engineer with a MBA in finance, is a Utility Management Expert with over 44 years of experience in the electrical utility industry. Mr. Snyder has held several positions at Manitoba Hydro including Vice President of Distribution and Transmission, Vice President of Power Supply, and VP of Corporate Services. Mr. Snyder lead the re-engineering of the Corporation into three Business Units; Generation, Transmission & Distribution, and Customer Service & Marketing. Mr. Snyder was responsible for the development and operation of Manitoba Hydro International for over 20 years. Al was active on both national and international utility committees including Canadian Electricity Association, Canadian Hydropower Association, Energy Council of Canada, and World Energy Congress chairing several of the organizations. Internationally, Mr. Snyder provided organizational re-structuring expertise in India, the Bahamas, Uganda, and Saudi Arabia with the Gulf Cooperative Council Inter-Connection Authority. Also, Mr. Snyder acted as the Deputy General Manager of Kenya Power and Light under an MHI Management Contract. Mr. Snyder is currently acting as the industry expert for the Utility Consumer Advocate in the Province of Alberta with respect to their 14 billion dollar investment in new transmission development. Allen Snyder is currently registered to practice engineering in the provinces of Manitoba and Newfoundland and Labrador.

Mack Kast, CA (Financial Project Manager)

Mr. Kast is a Chartered Accountant with over 35 years of experience in senior management positions in the electrical and natural gas utility sector. He has extensive experience abroad. Mr. Kast was Deputy General Manager, Finance and Corporate Services for two years with Kenya Power & Lighting Company (KPLC). During his tenure with KPLC, he assisted in raising the standards of the company allowing it to reach a higher level of achievement. The customer base was increased from 750,000 customers to over one million. He was extensively involved in the negotiation of power purchase agreements, strategic planning, tariff applications, performance measurement, and the transformation to achieve ISO 9000 status. Mr. Kast has been involved in various international assignments in Nigeria, Tanzania, Liberia, Albania, Romania, and Macedonia doing extensive regulatory and financial modeling and advising on tariff related matters. In his prior capacity with Manitoba Hydro, he was Division Manager of Gas Supply, where he was responsible for securing a reliable and cost effective supply of natural gas, and for implementing a customer based rate management program in an effort to minimize both costs and rate volatility, through the use of financial derivatives. Prior to Manitoba Hydro, Mr. Kast was Vice-President of Finance for Centra Gas Manitoba for 13 years. During this time, he assisted in merging the company and allowing it to prosper. He was involved with the filing of many regulatory applications and led testimony in support. He was also responsible for all financial and treasury matters, particularly as related to financial forecasts, raising long term financing, and the implementation of various process improvements. Prior to this, Mr. Kast worked for Ontario Hydro, both the Alberta Public Utilities Board and the Ontario Energy Board, and in public practice.

Bagen Bagen, P. Eng. (Reliability Expert)

Dr. Bagen is a respected industry expert in resource and power system planning particularly in the area of probabilistic or risk-based planning. He has over 16 years' experience in a variety of areas of power systems including resource planning, generation development, transmission planning, composite generation and transmission planning, interconnection facility/impact evaluation and transmission service request assessment. He was invited and nominated to several strategic industry planning committees including NERC Resource Issue Subcommittee (RIS), NERC Generation and Transmission Planning Model Task Force (GTRPMTS), NERC LOLE Working Group and MAPP Composite System Reliability Working Group (CSRWT) providing expert advice and leadership on various matters of planning, operating, strategic and technical importance. He also participates in the development of various internal, national and international standards such as Manitoba Hydro's loss of load expectation study criteria and procedures, Manitoba Hydro Transfer Capability Methodology for the Planning Horizon, Manitoba Hydro System Operating Limits Methodology for the Planning Horizon, the MRO resource adequacy assessment standard, NERC Methodology and Metrics for Probabilistic Assessment, NERC Facilities Design, Connections and Maintenance (FAC), NERC Modeling Data and Analysis (MOD) and NERC Transmission Planning (TPL). Dr. Bagen is currently registered to practice engineering in the provinces of Manitoba and Newfoundland and Labrador.

Robert Dandenault (Combustion and Thermal Gen. Expert)

Mr. Dandenault is a Power Engineer (First Class) with Canadian Inter-Provincial certification and is in the midst of completing an Executive Master's in Business Administration. Mr. Dandenault has over 25 years of utility experience with Manitoba Hydro in the areas of Operations and Maintenance of thermal, hydroelectric and HVDC converter stations. He has held various technical and leadership positions during his career. His experience includes, life extension works at two thermal stations, gas combustion turbine installation and commissioning, environmental management system (ISO 14001) development and chemical laboratory operations. His roles have included plant manager at thermal (coal-fired, gas turbines) and hydroelectric generating stations and most recently, resident operations advisor for Hidroelectrica de Cahora Bassa 2000 MW hydroelectric/HVDC converter station in Mozambique.

Craig Kellas (Load Forecast Expert)

Mr. Kellas is a market and load forecasting specialist with over 34 years of experience. Craig has managed the development of market research studies, market sector sales forecasts, total system energy forecasts, and hourly demand forecasts at Manitoba Hydro for both the gas and electricity markets. Craig managed the department responsible for analyzing monthly and annual customer billing information, designing and analyzing residential and commercial surveys, categorizing customers by building type and industrial classification, conducting energy use per square foot comparisons by building type, performing conditional demand analysis, developing hourly load models, calculating weather adjustments, and preparing forecasts by customer class, by industrial classification and by building type. In the performance of his duties, he held the post as the Energy Forecast Section chairperson for the Canadian Electricity Association, and as the Regional Load Forecasting representative for the Mid-continent Area Power Pool. On a previous MHI project, Craig assisted in the development of a report for the governing authority in Costa Rica, and documented the methodology, results and recommendations of the Load Forecasting and Market Research component of the Demand Side Management project.

Allan Silk, P. Eng. (Power Systems Studies Expert)

Mr. Silk is a professional engineer with over 22 years of experience with Manitoba Hydro, who is presently working with Manitoba HVdc Research Centre, a Division of Manitoba Hydro International as a Senior Consulting Engineer. In this role Mr. Silk provides project management services for a variety of projects with emphasis on transmission system operations, cost effective design, management and creation of capital plans, electrical master plans, and specification engineering for procurement. Previous to his current role, Mr. Silk was responsible for managing the Manitoba Hydro Open Access Interconnection Tariff. This included setting the wholesale rates for use of the bulk transmission system (the rates are approved by the Transmission Rates Committee), processing the applications for both tariffs, ensuring engineer studies to support tariff applications are completed within schedule, negotiating the service and operating agreements required by applicants to take tariff service. Mr. Silk was also responsible for initiating changes to the tariffs to ensure that they are current with open access practices. Allan Silk is currently registered to practice engineering in the provinces of Manitoba and Newfoundland and Labrador.

Alex Gerrard, P. Eng. (Hydro Generation Expert)

Alex Gerrard is a Professional Engineer specializing in Hydropower Engineering. Mr. Gerrard has more than 35 years' experience in engineering and management for hydroelectric power, water resources, and infrastructure projects. He has progressed from a mechanical and hydroelectric specialist to Vice-President and General Manager for engineering firms through roles as Project Manager and Manager of Engineering. His experience includes design and management of multi-disciplinary teams on large hydroelectric power and infrastructure projects in Canada as well as the U.S., Middle East, Africa, and Central America. In addition, Mr. Gerrard has been responsible for a wide variety of water resources, hydroelectric, power, and mining projects in Canada and overseas as Manager of Engineering and Projects. He has experience in project development for energy and transportation projects and in project delivery alternatives ranging from design-bid-build to build-own-operate-transfer schemes. Alex Gerrard is currently registered to practice engineering in the provinces of Manitoba and Newfoundland and Labrador.

Les Recksiedler, P. Eng. (HVdc Expert)

Mr. Recksiedler has over 39 years of electric utility experience and over 34 years in HVdc. Within his HVdc experience he has worked for over 26 years as a Stations Engineer on HVDC Projects and as a Maintenance Engineer for the operations and maintenance of 3 HVdc Converter Stations 3 854 MW, 500 kV dc including HVac Stations up to 500 kV ac. Based on this experience he was appointed the Subject Matter Expert for the new Bipole 3 (BP3) which was proposed for Manitoba Hydro's HVdc system. The BP3 is ±500 kV dc 2,000 or 2,500 MW line approximately 1500 km long. He provided the proposed O& M costs, staffing levels and estimated the major overhauls and capital replacements for a 35 year life span. Les was also the Subject Matter Expert for the power apparatus for the Reliability Centered Maintenance (RCM) adopted by Manitoba Hydro to reduce maintenance costs and improve equipment reliability. Lastly, as HVdc Engineering Department Manager Les was actively involved with and supported the Root Cause Analysis team which was developed to ensure the performance of the HVdc system remains at a high level. Les Recksiedler is currently registered to practice engineering in the provinces of Manitoba and Newfoundland and Labrador.

Charly Cadou, P. Eng. (Hydrology Expert)

Mr. Cadou is a highly experienced civil engineer with 39 years' experience in the field of water resources and hydro technical engineering, in Canada and overseas in Asia, the Americas, Africa and the Middle East. His work experience includes hydrological studies (both regional and project-specific); river basin and water resources planning and management; feasibility studies of water resources & hydropower projects; design and implementation of mitigation and remedial measures to environmentally detrimental river basin development; flood mitigation and flood forecasting studies; planning and operation of hydro-meteorological networks; stream gauging and water quality sampling; river hydraulics; river dredging; management of infrastructure rehabilitation projects, especially in post-conflict environments. Charly Cadou is currently registered to practice engineering in the province of Newfoundland and Labrador.

Enrico Colombo (HVDC and Cable Expert)

Mr. Colombo is a Professional Scientist with a Doctor's Degree in Physics and over 20 years of directly related cable experience. He is presently a Senior Scientist and project manager. His key qualifications include conceptual design, pre-feasibility and feasibility, line routing, selection and design of equipment, material list, technical specifications, cost evaluation, tender documents assistance, surveillance, factory acceptance test, construction and commissioning for transmission lines and substations (particularly for HVDC technology). Mr. Colombo has also written numerous publications relevant to his expertise in transmission and substations.

Sergio Meregalli (Submarine Cable Expert)

Mr. Meregalli is a professional engineer who possesses a Doctor' Degree in Electrical Engineering and over 15 years of directly related experience. He is a HV Cable Expert and is specialized in technical specifications (functional, design, manufacturing, testing), HVAC and HVDC cable. Two of Mr. Meregalli's most recent projects are a ±500 kVdc 2x600MW HVDC Link between Italy and Montenegro where he defined the technical specification and oversaw that bid evaluation and comparison and a ±320 kVdc 2x600MW HVDC Link between Italy and France were he performed the same services. Mr. Meregalli has also written numerous cable publications.

Randy Wachal, P.Eng. (HVDC and SVC Controls Expert)

Randy Wachal is the Research Projects and Engineering Services Manager at the Manitoba Hydro HVDC Research Centre and has 26 years of utility experience in power system operations, HVdc / SVC apparatus commissioning, and HVdc design. He is currently responsible for the PSCAD simulation support group and actively involved in many engineering services projects for Manitoba Hydro and other clients. They include the Xcel Lamar B2B HVdc Converter station, the Ponton and the Birchtree SVCs, and all research development projects currently underway at the Centre. He leads a diverse team of engineers, researchers, and laboratory staff and applies his superior technical project management in HVdc and power systems assignments. His thorough knowledge of power systems is evident through various publications on subjects such as electromagnetic transient simulation, PSCAD/EMTDC incorporation, load modelling for simulators, power system simulation, and others. Randy Wachal is currently registered to practice engineering in the provinces of Manitoba, Saskatchewan, and Newfoundland and Labrador.

Bob Buschau, P.Eng. (Renewable Energy Expert)

Mr. Buschau is a professional engineer with over 25 years of experience in the electricity industry. He is currently the General Manager of MCW/AGE Power Consultants responsible for the coordination, control, and quality assurance of various projects which include distribution system design, upgrade, and rehabilitation. Mr. Buschau has provided oversight of design efforts including development of conceptual designs for all projects, review and approvals of all aspects of design including lines, station protection and control, station arrangement and detailing, grounding, special reports, and scheduling. Mr. Buschau has been involved in numerous wind projects within North America with his most expansive project exceeding 400 MWs. Bob Bushau is currently registered to practice engineering in the province of Manitoba.

Rick Horocholyn, BSc(ME), MBA (Financial Specialist Support)

Mr. Horocholyn is a Financial Analyst with over 25 years of worldwide experience in financial consulting. He possesses both an MBA in Business Administration and a B.Sc in Mechanical Engineering from the University of Saskatchewan and has extensive experience with designing and developing financial planning models using both spreadsheets and specialized financial modeling tools. Mr. Horochoyln has detailed knowledge of power utility operations and issues applicable to model design for the support of operational and strategic decision-making. Within Manitoba Hydro, Mr. Horocholyn has developed and implemented the company's core models for financial planning and forecasting, capital planning, and debt/investment forecasting.

Luke Chaput, P.Eng. (Transmission Line Specialist)

Mr. Chaput is a professional engineer possessing a strong technical background. Mr. Chaput began his career in the Transmission & Distribution Construction Department at Manitoba Hydro before moving on to Transmission Line Studies, which was the precursor to his current position as Business Development Manager of W.I.R.E. Services. In this position Mr. Chaput undertakes worldwide business development which involves developing business relationships with clients and vendors, as well as managing service agreements with existing clients. He is also in charge of writing and presenting technical papers and seminars on Transmission Line Modeling and Analysis, and reviewing and responding to all forms of request for quotations regarding services provided by W.I.R.E. Services. Luke Chaput is currently registered to practice engineering in the provinces of Manitoba and Newfoundland and Labrador.

Peter Rae, P.Eng. (Hydro Power Expert)

Mr. Rae possesses a Master Degree in Civil Engineering with over 30 years of experience in Hydro generation project management. Currently, Mr. Rae is the Expansion Project Manager for Theun Hinboun Power Company in Laos. He has undertaken several projects with Theun Hinboun Power Company focusing on hydropower project development, hydropower expansion, and financial analysis and assessment of a Transmission upgrade project in southern Kyrgystan. On these projects Mr. Rae was involved as the project manager overseeing construction management, contract preparation, and tendering inputs to power purchase agreements, license agreement, financial analysis and assessment, and other commercial matters. Peter Rae is currently registered to practice engineering in the province Newfoundland and Labrador.

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