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 10, 2011

Executive Summary

As part of the comprehensive evaluation process for the Government of Newfoundland and Labrador (the Government) to move the development option of Muskrat Falls and the Labrador-Island Transmission Link (LIL) projects (the Projects) to sanction, the Government asked the Newfoundland and Labrador Board of Commissioners of Public Utilities (the Board) to provide a supplemental review of the process used to determine that the Projects represent the least cost option for the long-term supply of power to Island electricity customers. Specifically, the reference question to the Board is as follows:

> *The Board shall review and report to Government on whether the Projects represent the least cost option for the supply of power to Island Interconnected Customers over the period of 2011-2067, as compared to the Isolated Island Option, this being the "Reference Question"*[1].

This document summarizes the process Nalcor used to select the Interconnected Island alternative as the least cost source of power generation for Island rate payers. It also explains how Nalcor will proceed with constructing the project, as well as provides an overview of schedule, costs and risk management.

In preparing this report it was Nalcor's intent to demonstrate to the Board, and the people of the Province, the following:

- Nalcor has a responsibility to provide least cost power;
- the need for additional power generation to meet demand is clear;
- our analysis of supply alternatives was thorough and appropriate;
- our decision was in the best interests of our customers; and
- the project will provide our shareholder with an appropriate return on their investment.

[1] Government of Newfoundland and Labrador, *Terms of Reference and Reference Question*, 2011
http://www.pub.nf.ca/applications/MuskratFalls2011/files/corresp/TermsOfReference.pdf

Nalcor Energy was created by the Government to advise and execute policy direction as established by the Electrical Power Control Act (EPCA) and in the 2007 Energy Plan entitled "Focusing our Energy: Newfoundland and Labrador Energy Plan." To fulfill its mandate, Nalcor restructured and created a number of separate entities, including Newfoundland and Labrador Hydro (NLH). Its mandate is to provide the least cost supply of power to meet the electricity needs of the Province. This direction is the key principle which guides Nalcor's decisions related to power generation and supply.

Consistent with this mandate, each year NLH engages in a comprehensive load forecasting exercise to determine the province's electrical consumption requirements over a 20 year horizon. This process mirrors the practices of other jurisdictions and considers data from a number of sources, most notably NLH's own data analysis and modeling experience, economic projections from the provincial government, and input from industrial customers. A key consideration impacting demand in future years is the introduction of Vale's nickel processing facility presently being constructed at Long Harbour commence commercial operations beginning in 2013

A comparison of the 20 year load demand forecasts with available generating supply capacity found that capacity shortfalls would commence in 2015, where capacity is defined as the amount of available generation installed to meet peak electricity needs, including an appropriate reserve, to ensure peak demand can still be met if some generation is not available due to temporary problems with the power system. The consequence of a capacity deficit is that there is a risk that Nalcor may not be able to satisfy its customers' peak demands under certain contingencies.

The comparison of supply and demand also showed that as the capacity deficit increases beyond 2015, a firm energy shortfall begins to emerge starting in 2021. A firm energy deficit is defined as not having sufficient firm energy generation capability to supply the firm energy requirements of users across a year. The consequence of an energy deficit is that that the utility will not be able to meet customers' normal firm energy requirements under firm energy supply conditions.

The negative impacts associated with capacity and energy deficit are unacceptable to any regulated utility with a responsibility for wholesale generation supply and planning. Therefore, NHL began to identify and review a broad range of alternatives for consideration as future sources of electricity. This range included technologies that were well understood by NLH as they have been employed for more than 50 years, as well as relatively newer technologies that have been introduced or studied by Nalcor in the last 10-15 years. With respect to the Lower Churchill, both Gull Island and Muskrat Falls were included in the alternatives that were examined. Nalcor believes this to be a prudent step and represents a reasonable approach to focus its resources, efforts, and capital on those alternatives that are viable with respect to meeting future electricity supply requirements.

A two phase screening process commenced, with the initial phase 1 screening process employing five key principles:

1. Security of Supply and Reliability;
2. Cost to Ratepayers;
3. Environmental Considerations;
4. Risk and Uncertainty; and
5. Financial Viability of Non-Regulated Elements.

Phase 1 resulted in a number of alternatives being categorized as unsuitable for future feasibility studies. The initial screening is important as it enables NLH to concentrate further consideration on only the technologies and alternatives that offer the highest potential ensuring effective expenditure of rate payers' funds.

Those alternatives which were deemed acceptable for consideration and costing were grouped into two broad categories:

1) an Isolated Island alternative, in which the electrical system on the Island of Newfoundland continues to operate in isolation of the North American grid such that new generation capacity is limited to what can be developed on the Island itself; and

2) an Interconnected Island alternative which utilizes generation sources predominantly off the Island and depends on at least one transmission interconnection with the North American grid.

Industry standard technology was used to optimize the configuration of generation sources in each category.

The phase 2 screening process employed rigorous and proven methodologies. The Cumulative Present worth (CPW), a common metric for this industry, was calculated for each alternative to determine the present value of all incremental utility and operating costs. CPW's were then compared to confirm the long term least cost generation expansion plan. A further evaluation occurred to ensure transmission reliability was comparable and not compromised by either alternative.

The outcome of this system planning process found that the least cost option for the long term supply of generation for the Island was the Interconnected Island alternative, featuring the development of Muskrat Falls coupled with the construction of a transmission interconnection between central Labrador and the Island of Newfoundland. This recommended investment alternative has a CPW preference of almost $2.2 billion over an isolated island alternative, and is robust under a broad range of sensitivities.

Independent of the system planning work, Nalcor has been actively engaged progressing the development of the Lower Churchill as directed by the Energy Plan. That plan provided policy direction in five areas that are relevant to this review. They were:

1. Nalcor was to take a lead role in the development of the Province's energy resources;
2. The Province would take a lead role in developing the Lower Churchill, and was to identify transmission access to other electricity grids;
3. The environmental concerns associated with the Holyrood Thermal Generating Station needed to be addressed. Two alternatives were presented:
    a. Electricity from the Lower Churchill Project; or

   b. Installing scrubbers and precipitators, and maximize the use of wind, small hydro and energy efficiency programs to reduce the reliance on Holyrood;

4. A comprehensive study of all potential long-term electricity supply options would be developed in the event that the Lower Churchill Project did not proceed.

A Lower Churchill Project Team was formed and has progressed work on engineering definition, market analysis, consultations with aboriginal groups and the negotiation of an Impacts and Benefits Agreement, Water Management Agreements concerning the Upper Churchill, and preparation and participation in the Environmental Assessment process.

A secondary benefit, which is outside of the scope of the Board's review, involves the construction of a transmission link from the Island of Newfoundland to Nova Scotia to facilitate the export of electricity that is surplus to the Province's needs. During the early years of production, Island requirements are projected to be about 40% of the annual energy production capability of Muskrat Falls. As demand on the Island grows in line with the economy over the next 40 years, the remaining power will be required for internal use. In the interim, however, the Province has the opportunity to secure significant value from the potential sale of the remaining 60% unused energy.

In order to access this value, Nalcor explored several market opportunities and subsequently negotiated a commercial agreement with Emera. This agreement will result in the construction of a 500MW HVdc transmission link between the Island of Newfoundland and Nova Scotia. This line will deliver power to Nova Scotia under the terms of the agreement and also be available for Nalcor to export surplus power from Muskrat Falls. As the power initially sold into short term export markets is required to meet internal needs, Nalcor would have the option of introducing new generation sources to fill any unused capacity in the Maritime Link. This is a source of additional long term revenues for the province, and allows Nalcor to continue with plans to develop other renewable sources of electricity, such as wind and smaller scale hydro developments.

Value is also present in the environmental benefits associated with eliminating greenhouse gas and other atmospheric emissions from Holyrood, as stated in the Energy Plan. Once the Lower Churchill Project comes in-service in 2017, electricity generation in the province will be 98% GHG free. With the introduction of the Maritime Link, this positive footprint will expand to Nova Scotia, where coal fired generation will be displaced with renewable energy from Muskrat Falls.

A final point involves the impact this Project will have on wholesale and retail electricity prices. The increases in electricity rates which are expected to occur between now and when power becomes available from Muskrat Fall are in no way associated with the cost of building Muskrat Falls. Nalcor is not permitted to recover any of the costs which are associated with Lower Churchill Project until the project goes in service and begins supplying electricity to the Island. Rather, these increases are largely driven by the increasing cost and quantity of heavy fuel oil burned at Holyrood to produce electricity in the interim. Were it not for the development of the Lower Churchill Project, electricity prices would continue to increase hand and hand with the price of fuel, compounded by a growing base of thermal electricity production in they future. Once the Lower Churchill Project is integrated into the Island rate base, the cost structure for NLH will change and electricity prices will stabilize and provide increasing value to all users over time. That desirable outcome is fully consistent with NLH's mandate, and is consistent with our decision to recommend an Interconnected Island alternative as the least cost long term electricity supply future.

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

Volume 1

November 10, 2011

Note to Reader

This report references exhibits and responses to requests for information filed with the Newfoundland and Labrador Board of Commissioners of Public Utilities (the Board) by Nalcor Energy. Exhibits and responses to requests for information (RFIs) are classified as either public or confidential. Confidential exhibits (CEs) have been deemed so by Nalcor where the information contained within is of a commercially sensitive nature. All public exhibits, including abridged or redacted versions of confidential exhibits, are available at the Board's website

Exhibits:	http://www.pub.nf.ca/applications/MuskratFalls2011/nalcordocs.htm
Responses to RFIs	http://www.pub.nf.ca/applications/MuskratFalls2011/rfi.htm
Public CE's:	http://www.pub.nl.ca/applications/MuskratFalls2011/abridge.htm

Table of Contents

List of Figures

List of Tables

List of Acronyms

Acronym	Definition
ac	Alternating current
AFUDC	Allowance For Funds Used During Construction
BACT	Best Available Control Technology
CCCT	Combined Cycle Combustion Turbine
CCS	Carbon Capture and Storage
CDM	Conservation and Demand Management
CE	Confidential Exhibit
CF	Churchill Falls
CF(L)Co	Churchill Falls (Labrador) Corporation
CO_2	Carbon Dioxide
COS	Cost of Service
CPI	Consumer Price Index
CPW	Cumulative Present Worth
CT	Simple Cycle Combustion Turbine
dc	Direct current
DG2	Decision Gate 2
DG3	Decision Gate 3
EOR	Enhanced Oil Recovery
ESCR	Equivalent short circuit ratio
ESP	Electrostatic precipitators
FGD	Flue gas desulphurization (i.e. Scrubbers)
fob	Free on board
GDP	Gross Domestic Product
GHG	Greenhouse Gas
GWh	Gigawatt Hour
HRSG	Heat Recovery Steam Generator
HVdc	High Voltage Direct Current
IDC	Interest during construction
IRR	Internal Rate of Return
km	Kilometre
kW	Kilowatt
kWh	Kilowatt hour
LCP	Lower Churchill Project
LFO	Light Fuel Oil (i.e. diesel)
LIL	Labrador-Island Transmission Link
LNG	Liquefied Natural Gas
LOLH	Loss of Load Hours
MBTU	Millions of British Thermal Units
MF	Muskrat Falls
MW	Megawatt
MWh	Megawatt Hour
NERC	North American Electric Reliability Corporation
NLH	Newfoundland and Labrador Hydro
NOx	Nitrous Oxide
NP	Newfoundland Power
NUG	Non-Utility Generator
O&M	Operating and Maintenance

Acronym	Definition
PLF	Planning Load Forecast
PM	Particulate Matter
PPA	Power Purchase Agreement
PPI	Producer Price Index
PV	Photovoltaic Cell
RFP	Request for Proposal
RRM	Revenue Requirement Model
SO_2	Sulphur Dioxide
TWh	Terawatt Hour
WACC	Weighted Average Cost of Capital

"Intentionally Left Blank"

1.0 Introduction

1.1 Purpose

The purpose of this report is to summarize the system planning process used by Newfoundland and Labrador Hydro (NLH) to establish the Isolated Island and Interconnected Island long-term electricity supply alternatives, and to summarize the analysis that concluded that Muskrat Falls is the least cost option for the long-term supply of power for the island's electricity consumers.

1.2 Background

As part of the comprehensive evaluation process for the Province of Newfoundland and Labrador to move the development option of Muskrat Falls and the Labrador-Island Transmission Link (LIL) projects (the Projects) to sanction, the provincial government asked the Newfoundland and Labrador Board of Commissioners of Public Utilities (the Board) to provide a supplemental review of the process used to determine that the Projects represent the least cost option for the long-term supply of power to island electricity customers. Specifically, the reference question to the Board is as follows:

> *The Board shall review and report to Government on whether the Projects represent the least cost option for the supply of power to Island Interconnected Customers over the period of 2011-2067, as compared to the Isolated Island Option, this being the "Reference Question"* [1].

The Terms of Reference further stated:

> *In answering the Reference Question, the Board:*
>
> - *shall consider and evaluate factors it considers relevant including NLH's and Nalcor's forecasts and assumptions for the Island load, system planning*

[1] Government of Newfoundland and Labrador, *Terms of Reference and Reference Question*, 2011
http://www.pub.nf.ca/applications/MuskratFalls2011/files/corresp/TermsOfReference.pdf

assumptions, and the processes for developing and comparing the estimated costs for the supply of power to Island Interconnected Customers; and

- *shall assume that any power from the Projects which is in excess of the needs of the Province is not monetized or utilized, and therefore the Board shall not include consideration of the options and decisions respecting the monetization of the excess power from the Muskrat Falls generation facility, including the Maritime Link project.*

The Terms of Reference included a basic description of two options to supply power to Island Interconnected customers, development of the Muskrat Falls generation facility and LIL (Interconnected Island alternative) and the continued operation of the Holyrood Thermal Generating Station and the development of other indigenous generation sources (Isolated Island alternative). It also directed Nalcor Energy to further outline both of these alternatives in a submission to the Board.

1.3 Report Structure

The structure of this report reflects the system planning process NLH employed to determine the least cost option for the supply of power to the Island Interconnected system. This document begins with identifying the reference question from the Board, and provides a brief background to set the context for the report. It culminates with the recommendation of an Interconnected Island generation configuration which features the development of Muskrat Falls and the construction of LIL, which interconnects Central Labrador and the island of Newfoundland.

Load forecasting, which is the first step in NLH's system planning process is described in Section 2 of the report. It describes the methodology employed and the economic assumptions used to develop the 20-year Planning Load Forecast (PLF). Historical and forecast loads are presented as well as the economic inputs and methodologies used to calculate them. This annual PLF is used to identify the need and timing of new generation capacity.

A second ongoing component of the system planning function is assessing the adequacy of existing generation capacity. The existing system capability is first described and then assessed against the PLF using predefined planning criteria for both generation and transmission. Section 3 of the report describes the system planning criteria, methodology, and tools used in completing this assessment. The outcome identifies planning triggers for both generation and transmission that require action by NLH.

The next step of the planning process involves identifying alternatives to mitigate the shortcomings identified in the needs assessment. A two-phased screening process was used to evaluate alternatives. Section 4 outlines phase 1 screening and describes the alternatives considered. The outcome is a list of viable alternatives that would be further evaluated and costed for system planning purposes.

The first step in phase 2 screening involves grouping alternatives into two broad categories, or options, of development alternatives. One option, as described in Section 5, is categorized as the Isolated Island alternative. In this alternative, the electrical system on the island of Newfoundland continues to operate in isolation from the North American grid such that new generation capacity is limited to what can be developed on the island itself. The second option is categorized as the Interconnected Island alternative and is described in Section 6. The Interconnected Island alternative depends on at least one transmission interconnection with the North American grid and utilizes generation sources predominantly located off the island.

A common industry metric known as Cumulative Present Worth (CPW) is calculated for both alternatives. This metric determines the present value of all incremental utility and operating costs. In Section 7, a comparison of CPW is used in the phase 2 screening and evaluation process to confirm the long-term least cost generation expansion plan. This section also provides a sensitivity analysis presented to assess the robustness of the economic preference arising from the CPW analysis.

A subsequent evaluation process is used to compare transmission reliability for both the Interconnected Island and Isolated Island alternatives. As described in Section 8, this comparison is used to ensure the alternatives have comparable reliabilities.

Section 9 considers the impacts each generation expansion alternative will have on the trends in overall wholesale rates for island ratepayers.

In Volume 2 of this submission, the Muskrat Falls and LIL projects are discussed in further detail. Given the amount of front-end engineering, planning, design and technical analysis undertaken for these projects, it was deemed prudent to include a separate volume summarizing Nalcor's level of effort in this regard.

2.0 Load Forecasting

Section 2 provides an explanation of why and how load forecasting is prepared at NLH including historical load information and the current economic conditions in Newfoundland and Labrador that shape the outlook for the island's future electricity needs. A summary of the 2010 PLF used to determine the need for new generation is provided at the end of the section.

Under current legislation, the Board "has the authority and responsibility to ensure that proper planning occurs" for meeting the short and long-term electricity requirements for the Province. NLH has undertaken this activity for more than 40 years.

2.1 Long-Term Forecasting

Preparing a long-term load forecast is the first step in the planning process as it establishes the anticipated electricity requirement for the province's consumers. Information concerning the province's future annual energy and peak demand requirements is required to determine the timing and plant design of future generation sources. Electricity demand changes over time, reflecting the overall growth or decline in a region's economic activity. In addition, market factors relating to available fuel choices and pricing have an impact on electricity demand, as well as changes in technology and energy efficiency. The purpose of load forecasting at NLH is to project electricity demand and energy requirements through future periods to ensure sufficient generation resources are available to reliably meet consumers' requirements. The long-term load forecast aims to minimize the operational risks between inadequate capacity and the financial risks of excessive electricity resource capability, and the economic burdens placed on all consumers in either circumstance.

Long lead times are often required following a decision to add new generation capability to the system because sufficient time is needed to design and construct the new facilities. The long-term load forecast aims to minimize the economic burdens placed on all consumers due to supply interruption risks caused by inadequate capacity and the financial risks of excessive electricity resource capability.

The majority of the province's generation capability is owned and operated by NLH. The company monitors the long-term demand and supply balance and schedules production and transmission for its own assets as well as accounting for those generation assets owned and operated by Newfoundland Power and Non-utility Generators (NUGs). NLH undertakes, within defined reliability criteria approved by the Board, to have resources in place to serve whatever requirement households, businesses and industries may simultaneously demand. As electricity cannot be withdrawn or rationed except in emergency situations, producer supply is needed to meet simultaneous customer demand.

2.2 Current Environment

Provincial Economic Overview

The Province of Newfoundland and Labrador is experiencing significant economic growth with strong gains in Gross Domestic Product (GDP), personal income and employment. According to the Canadian Mortgage Housing & Corporation, current indicators of growth for 2011 include strong employment gains and solid growth in consumer spending activity. Economic growth will also come from the province's considerable infrastructure spending program[2].

In 2010, Newfoundland and Labrador led the country in terms of employment growth. According to the provincial department of Advanced Education and Skills, employment grew by 3.3 percent from 2009 to 2010 - the highest level recorded for the province in the past 35 years. Comparatively, in Canada, employment grew by 1.4 percent between 2009 and 2010[3]. The strong growth in employment led to a decline in the unemployment rate in 2010. The unemployment rate is expected to continue to trend downward and high levels of consumer confidence will continue to support consumer spending.

The province's Economic Review 2010 (published by the Department of Finance, November 2010) stated the continued strength of the provincial economy is contributing to net in-

---

2 Canada Mortgage and Housing Corporation, *Housing Market Outlook: Canada Edition*, Third Quarter 2011 http://www.cmhc-schl.gc.ca/odpub/esub/61500/61500_2011_Q03.pdf?fr=1319711716485

3 Government of Newfoundland and Labrador, *Newfoundland and Labrador Labour Market Outlook 2020*, 2011 http://www.hrle.gov.nl.ca/hrle/publications/LMOutlook2020.pdf

migration and an increase in the province's overall population. According to the Department of Finance, 2010 marked the second consecutive year of population growth after 16 years of decline. As of July 1, 2010, Newfoundland and Labrador's population stood at 509,739, an increase of 0.3 percent compared to July 1, 2009[4]. While the growth in GDP will vary due to the timelines of major projects and the production profile for oil, other economic indicators such as employment and income are expected to continue to increase because of broadly based economic activity in the province. Employment incomes have been steadily rising throughout Newfoundland and Labrador. Between 2002 and 2010, the average weekly wage rate for Newfoundland and Labrador increased by 4.2 percent per year on a compound annual growth rate basis. This compares to the average annual inflation rate for the province of 2.0 percent for the same period, meaning people have more income to spend[5].

Economic growth is continuing through 2011. This growth is driven largely by major project development, including construction on Vale Newfoundland and Labrador Ltd.'s (Vale) nickel processing facility. In addition, developments related to the province's offshore oil resources including the Hebron development the White Rose expansion fields and ongoing exploration activity are also contributing factors to the province's economic growth.

Operating Environment

There are recognized challenges and unique characteristics in planning the generation and transmission of electricity in Newfoundland and Labrador. These include low customer density, population migration to the Avalon Peninsula, varying electricity demand by season, topography and the isolation of the island electricity grid.

For many utilities, the ability to access surplus power from neighbouring producers enables them to postpone investment decisions and rely on neighbouring jurisdictions for back-up generation capability in case of emergencies. For the island system, NLH does not have the operating flexibility and investment advantages that are enjoyed by interconnected utilities.

---

[4] Government of Newfoundland and Labrador, *The Economic Review 2010*, 2010 http://www.economics.gov.nl.ca/ER2010/TheEconomicReview2010.pdf

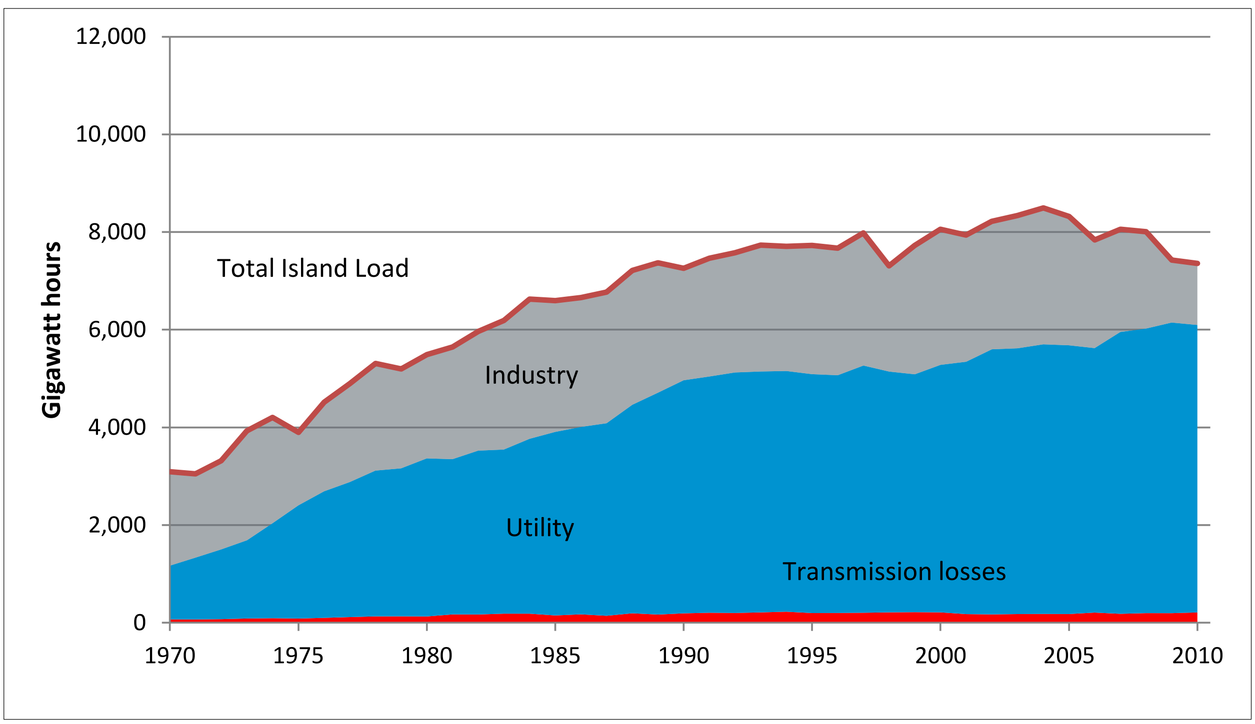
[5] Government of Newfoundland and Labrador, *Newfoundland and Labrador Labour Market Outlook 2020*, 2011 http://www.hrle.gov.nl.ca/hrle/publications/LMOutlook2020.pdf

As a result, generation investment alternatives tend to be more limited and influenced by the lead time to construct new generation.

2.3 Historical Load Growth

The review of historical electrical load growth on the island presented in this section provides background to the 2010 PLF. Figure 1 below shows total island load from 1970 to 2010, including the breakout of utility and industrial customer load across the same time period. Utility load refers to the domestic and general service class load requirements for the service territories of Newfoundland Power and NLH Rural on the existing island grid. The domestic class is primarily households with the general service class comprised of commercial and light industrial accounts. Industrial load refers to the requirements for the island's larger industrial customers directly served by NLH. It should be noted that although historical patterns are an input to NLH's load forecasting, they do not represent an absolute baseline for future forecasting.

Figure 1: Total Island Load (1970-2010)

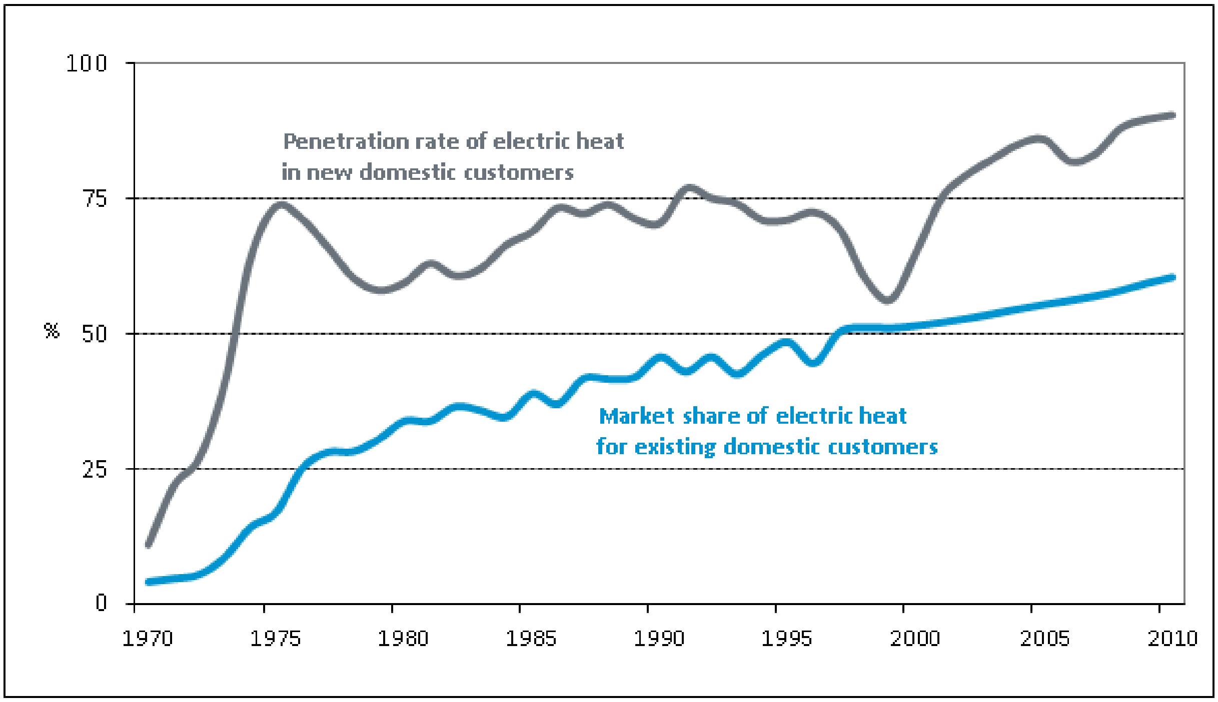


Sources: (1) NLH, *Total Island Interconnected Load*, 2011 (Exhibit 58)
(2) NLH, System Planning

Electricity Use From 1970 to 1990

The bulk power supply for the island, and the island-wide high voltage transmission network, was constructed and commissioned beginning around the mid 1960s. The years from 1970 to 1990 represent the period of most intensive load growth on the total Island Interconnected system with the compound average growth rate for the period being 4.4 percent per year. The breakout of this annual compound growth for total utility load was 7.5 percent per year, while for industrial it was 0.7 percent per year. In addition to it being a period of robust customer growth (expansion of the island grid to include many rural communities also contributed), utility customers began adopting electric space and water heating in the majority of new homes and businesses. This was followed by conversions to electric heat in many existing houses. Development of the island's electric power sector in the mid-1960s resulted in access to electric power supplies at competitive prices, which set the stage for electricity gains in a previously untapped market for home heating. This was subsequently accelerated by the "energy crisis" of the early 1970s when there was a sharp increase in the cost of oil. Over the course of a few years the penetration rate for electric heat in new home construction increased from less than 10 percent of new customers to about 70 percent and consistently remained in the 60 to 75 percent range, generally irrespective of short-term changes in alternative energy prices. Figure 2 on the next page presents the historical penetration rates for electric heat experienced in Newfoundland Power's domestic customer additions and the resulting market share.

Figure 2: Residential Electric Heat Penetration and Market Share



Sources: (1) NLH, *Total* Island *Interconnected Load*, 2011 (Exhibit 58)
(2) NLH, System Planning

During the energy crisis periods in the 1970s, there were accelerated conversions of existing customer accounts from non-electric to electric space heating. Such conversion activity was largely at the expense of home heating fuel oil companies. By the end of 1989, the provincial market shares for electric space heating and hot water, as reported by Statistics Canada, stood at 42 percent and 82 percent respectively.

Within the same period, the presence of major residential household appliances such as electric stoves, clothes washers, clothes dryers, freezers, etc., also increased. By the end of 1989, most standard household appliances could be found in the majority of households, with some nearing full market saturation. The automatic dishwasher had the most remaining growth potential as it was reported in less than 20 percent of households. The provincial saturation levels for electric heating and appliances as reported by Statistic's Canada are provided in Table 1.

Table 1: Provincial Saturation of Electric Appliance Equipment (% of all households)

Electric Equipment	1979	1989	1999	2009
Refrigerators	96%	98%	100%	100%
Cooking	71%	95%	98%	99%
Washers	*39%	*67%	93%	95%
Dryers	46%	69%	84%	93%
Freezers	61%	74%	81%	80%
Dishwasher	9%	20%	33%	49%
Hot Water	**62%**	**82%**	**86%**	**89%**
Space Heat	**30%**	**42%**	**49%**	**63%**
Note: *Saturation for automatic washers.				

Sources: Statistics Canada, *Survey of Household Spending*
Statistics Canada, *Households, Facility and Equipment: Catalogue 64-202*

On the Island Interconnected system the 1970-1990 period started with three major industrial loads and ended the period with four. Across this period, industrial load increased due to the addition of a third newsprint mill on the island, oil refining and the opening of the gold mine at Hope Brook. Most of this increased industrial load requirement across the period was offset near the end of the period with the closure of the elemental phosphorous plant at Long Harbour.

<u>Electricity Use From 1990 to 2010</u>

During this latter 20-year period, load growth was much less intensive than earlier with the compound annual growth rate for the total island load of only 0.1 percent per year for the 20-year period. While the growth rate reflects the actual change in the total island's interconnected load during that time, the particular significant changes that occurred with the utility and industrial load components within this annual growth rate provide insight with respect to the specific trends of these two customer groups.

Following the closure of the paper mills in Stephenville and Grand Falls, as well as the paper machine shut-downs in Corner Brook, industrial load on the island declined by 45 percent.

By contrast, the island's utility load, which includes all residential, commercial and light industrial electricity use, grew by a compound annual growth rate of 1.1 percent

(1.3 percent on a normalized weather basis[6]) across the 20-year period. A noteworthy aspect of utility load in the 1990s was the virtually flat load growth that coincided with the structural changes within the provincial economy due to the fishery moratoria. Utility customer growth declined, and as oil prices had declined in the late 1990s, the penetration rate for electric space heat dropped to near 50 percent. By 2000, the initial large structural impacts of fishery adjustment were over and utility load growth began to rebound. Combined with an expanding provincial economy and an increase in global oil prices pushed the penetration rate for electric space heat to historically high levels. Utility growth in the 2000-2010 period was higher than in the previous decade and recorded a 1.5 percent annual compound growth rate (1.6 percent on a normalized weather basis). The market share for electric space heating now stands at more than double the share in 1979, reaching 63 percent in 2009.

2.4 Forecasting Methodology

NLH normally completes one long-term load forecast analysis annually beginning in the last quarter of each year. The annual development of long-term load forecasts ensures, to the extent possible, that the constantly shifting set of inputs and parameters affecting the province's electricity demand are incorporated into current utility operating plans and investment intentions.

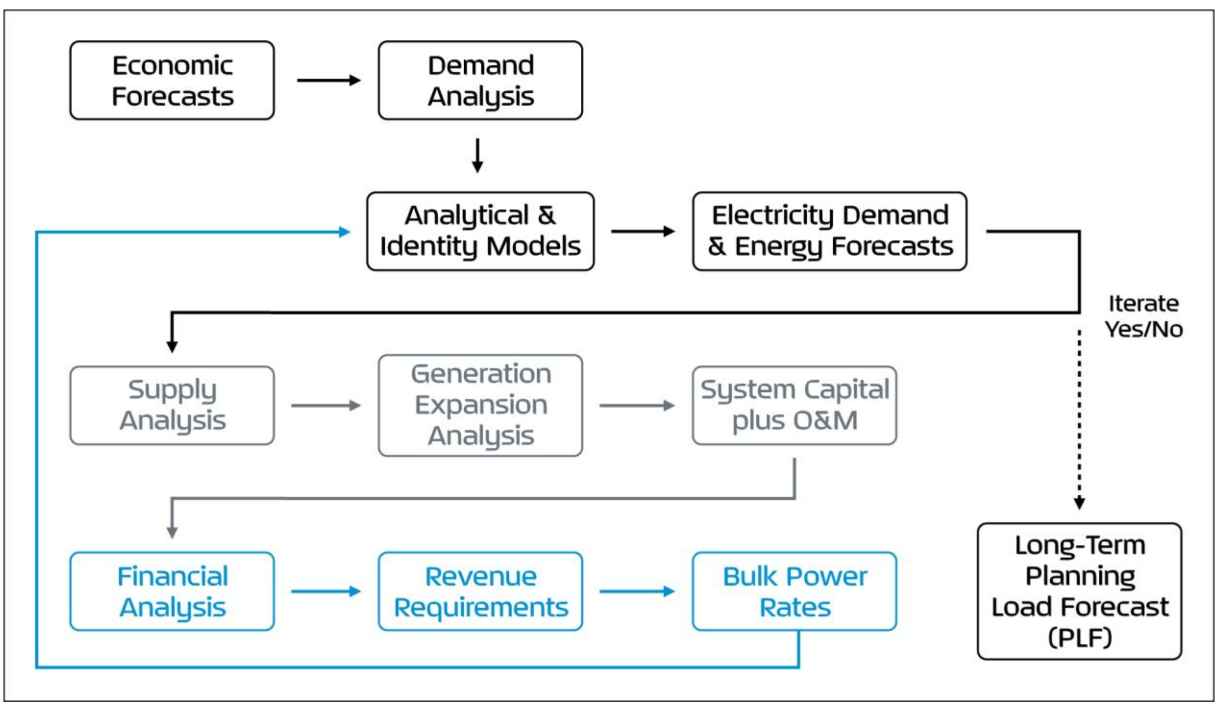
The load forecasting model utilized by NLH is an econometric based model used to project the island's energy and peak demand requirements 20 years into the future. Across the historical period, typically from the late 1960s, the relationships between changes in electricity use and various economic measures are quantified using econometric techniques. This information forms the basis of expected demand levels in future periods, given a certain set of economic conditions. The statistical effort behind the load forecast is primarily directed at long-term forecasting for the utility component of the island's total requirements, which is the load forecast for the combined service territories of

[6] Adjusted utility sales to account for warmer or colder weather conditions for a given year compared to historical normal weather conditions.

Newfoundland Power and NLH Rural. Data sets and econometric equations, along with all other modeling parameters, are reviewed and updated annually. Once updated, the load forecast model builds up to a forecast of utility load by aggregating forecasts of domestic and general service retail rate classes.

Change in general service load is linked to change in provincial GDP and investment levels in commercial building stock, while domestic load changes are linked to average electricity consumption and customer levels. Domestic customer levels are primarily driven by housing starts while average consumption levels are predicated on the basis of changes to personal income, electric heat market share and price. Annual efficiency improvement is also a feature of the load forecast model and includes the energy conservation and technological changes to utility loads as measured from the historical data. Figure 3 details the work flow and processes involved in completing a long-term load forecast cycle within NLH. Given the prevailing economic and industrial load outlook, this process leads to the demand, capital, operating cost and rate analysis.

Figure 3: Load Forecast Cycle



Source: NLH, *Summary of Newfoundland and Labrador Hydro 2010 Long Term Planning Load Forecast*, 2010 (Exhibit 27)

To drive the electricity forecast model, a 20-year macroeconomic forecast for the provincial economy is received from the province's Department of Finance. The Department of Finance regularly prepares a five-year provincial macroeconomic forecast for their own purposes, using their own econometric model of the provincial economy. For NLH, the initial five-year period of the provincial macroeconomic forecast is aligned with the provincial government's own five-year economic forecast with an additional 15 years of macroeconomic data provided to meet NLH's requirements. The key load forecast inputs from the Department of Finance include projections of GDP, personal income levels, new housing units and population. Twenty-year projections for petroleum prices are prepared internally using information received from the PIRA Energy Group, a consultancy from New York specializing in international energy pricing matters. These internally prepared petroleum prices provide inputs for NLH thermal generation production costing, and retail pricing in island energy markets that form part of the economic inputs to the load forecast model.

For the large industrial customers directly served by NLH, direct input from those customers forms the basis for NLH's forecast of total industrial electric power requirements. Given the small industrial customer base, it would not be appropriate for NLH to forecast industrial requirements independent of the input provided by the industrial customers themselves.

Once updated, the load forecast model combines the residential and commercial components of utility load with direct industrial loads in order to derive the total Island Interconnected load, the level at which NLH undertakes system reliability, and the resource requirement analysis.

For the Muskrat Falls and LIL generation expansion analysis it was necessary to extend the standard 20-year long-term load forecast for an additional 38 years to coincide with the service life of the transmission link. Given the extended forecast period involved, it was considered prudent not to simply extend the forecast by applying a fixed growth rate year over year to the 2029 island load as this would result in compounding effects on load across the 38-year extended period. It was also recognized that the saturation of electric heat within the residential customer class would be reached, at an expected target of about 80 percent. Once the electric heat market was saturated, continued load growth would reflect an expected conservative level of continued economic growth within the provincial economy.

For the 2010 PLF, the island load forecast was extended beyond the 20-year econometric forecast period, based initially on the average gigawatt hour (GWh) growth in energy for the last five years in the forecast. This is the period from 2024 to 2029. The annual GWh growth in energy was subsequently reduced in five to 10 year intervals to reflect the growing yet maturing market saturation for electricity in heating markets, while maintaining an annual load increment to reflect basic underlying provincial economic growth. The impacts of material reductions in future load expectations are addressed through discrete load sensitivity cases. Sensitivity analyses are discussed in Section 7.2.

2.5 Key Forecast Assumptions and Drivers

Table 2 presents the 2010 PLF growth rates for the primary drivers of residential, commercial and light industrial electricity sales for the Island Interconnected system. Some of the main factors that play a role in the economic forecast that underscore the long-term load forecast for the island are:

- Oil production from Hebron begins in 2017 and is still producing in 2030 with oil production from existing projects declining over the forecast period.
- Improvements to ground fish stocks allowing increased landings over the forecast period but lower landings from existing levels of other species.
- Continued newsprint production at Corner Brook over the forecast period.
- The Vale nickel processing facility is constructed with production of finished nickel from the facility beginning in 2013.
- The Come-by-Chance refinery continues to operate at current capacity over the forecast period.
- No provision for further large, unforeseen industrial load locating on the island's power system in the forecast period has been included.

Table 2: Provincial Economic Indicators - 2010 PLF

	Historical	Forecast		
Indicator	**1989-2009**	**2009-2014**	**2009-2019**	**2009-2029**
Adjusted Real GDP at Market Prices* (% Change Per Year)	1.4%	1.5%	1.0%	0.9%
Real Disposable Income (% Change Per Year)	1.2%	1.5%	1.0%	0.9%
Average Housing Starts (Number Per Year)	2,333	2,575	2,400	2,135
End of Period Population ('000s)	509	515	510	507

*Adjusted GDP excludes income that will be earned by the non-resident owners of Provincial resource developments to better reflect growth in economic activity that generates income for local residents.

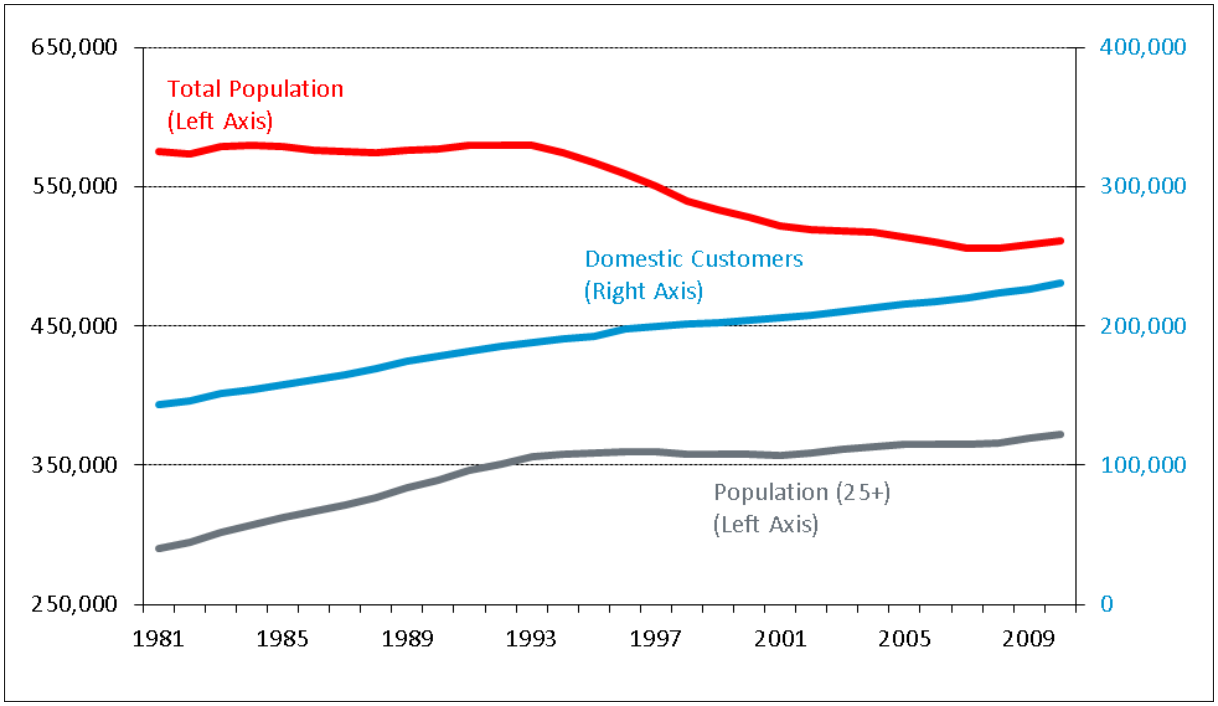
Source: Government of Newfoundland and Labrador, Department of Finance

Sustained by the province's oil and nickel processing developments, economic growth to 2014 is forecast to be greater than in the previous 20-year period, contributing to growing utility sales. Economic growth is expected to moderate once the current resource projects are in place with long-term growth at a somewhat lower growth rate than in the previous 20 years.

Table 2 above indicates that population is forecast to increase in the near term and slowly decline out to the end of 2029. While this population trend appears to conflict with the province's outlook for continued housing starts, a closer look at historic provincial population data helps explain, to a large degree, why the provincial housing stock and associated domestic customer base continues to expand.

Figure 4 presents the historical provincial population and Island Interconnected domestic customer growth.

Figure 4: Provincial Population and Island Interconnected Domestic Customers



Sources: (1) Government of Newfoundland and Labrador, Department of Finance
(2) Newfoundland Power, year-end customer data
(3) NLH, System Operations, Customer Service Group

As depicted in Figure 4, the number of domestic customers has continued to grow despite the province's declining population. This has occurred because household and customer formation are naturally more related to the subset of population that is 25 years and older. This is the age subset which predominantly forms households and drives the demand for housing. Changes in real personal income have also been historically linked to customer growth.

Table 3 presents the two key statistics that summarize the impacts to the island's electric heating market as forecast in the 2010 PLF.

The preference for electric space heating across residential and commercial customers continues to be an important source of load growth for the utility sector on the island.

Table 3: Summary Statistics for Island Residential Electric Heat

	Historical	Forecast		
	1989-2009	2009-2014	2009-2019	2009-2029
Average Penetration Rate of Electric Heat in New Domestic Customers (% Per Year)	75%	86%	84%	86%
End of Period Electric Heat Market Share (%)	61.3%	63.1%	64.7%	68.2%
* For Newfoundland Power Service Territory				

Source: Newfoundland Power, direct contact and year-end customer data

Conservation and Efficiency in Newfoundland and Labrador

Electricity conservation and efficiency programming in Newfoundland and Labrador is delivered by the utilities through a joint utility effort. In 2007, NLH and Newfoundland Power commissioned Marbek Resource Consultants Limited (Marbek) to complete a Conservation and Demand Management (CDM) potential study[7] that provided analysis and information to assess the potential contribution of specific technologies and efficiency measures, identify ranges for achievable potential, and assist in identifying cost-effective conservation programs. The key CDM achievable estimates from the Marbek study are provided in Table 4 below.

Table 4: Achievable Energy Conservation Estimates

	Upper Achievable Estimate (GWh)	Lower Achievable Estimate (GWh)	Savings as a % of Base Year Consumption	
			Upper	Lower
Residential	439	236	14%	7%
Commercial	387	261	21%	14%
Industrial	125	59	9%	4%
Total	951	556	15%	9%

Source: Marbek Resource Consultants Ltd., *Conservation and Demand Management (CDM) Potential Newfoundland and Labrador*, 2008

takeCHARGE is the joint utility energy efficiency marketing program developed and administered by NLH and Newfoundland Power through which CDM information and

[7] Marbek Resource Consultants Ltd., *Conservation and Demand Management (CDM) Potential Newfoundland and Labrador*, 2008

programs are delivered. The utilities plan and develop a common portfolio of rebate programs for residential and commercial customers, with each utility delivering the resulting programs to their own customers. In 2008, NLH and Newfoundland Power jointly filed a *Five-Year Energy Conservation Plan: 2008 – 2013*[8] with the Board, which outlined proposed energy conservation initiatives to be implemented including technologies, programs, support elements and cost estimates that promote a long-term goal of establishing a conservation and efficiency culture. The joint plan presented a target of 79 GWh per year in savings by the plan's final year in 2013. In addition to this effort, NLH has also launched its Industrial Energy Efficiency Program, providing customized approaches for energy savings for NLH's large direct industrial customers. Table 5 provides the conservation targets and savings achieved thus far.

Table 5: Energy Conservation Targets and Achievements

Sector	2009 Savings (GWh/year)		2010 Savings (GWh/year)	
	5 Year Plan Target	Actuals	5 Year Plan Target	Actuals
Residential	3.1	2.5	6.6	4.6
Commercial	0.7	0.2	1.7	0.7
Industrial	-	-	-	-
Total	**3.8**	**2.7**	**8.3**	**5.3**

Source: NLH, System Operations and Customer Service

To date, the response to CDM programs and initiatives has been modest and lagging targets. NLH has not explicitly incorporated these utility sponsored program savings targets into its planning load forecast due to the uncertainty of achieving dependable firm outcomes. The annual efficiency gains measured in the load forecast models are forecast to continue to the end of the forecast period. NLH will re-assess what are reasonable assumptions to include regarding sponsored CDM savings over the longer term with each load forecast cycle. For the Isolated Island alternative, sensitivity analyses addressing the economic impact on generation planning of achieving an aggressive CDM target, at 750 GWh per year by 2031, along with a more moderate savings profile of 350 GWh have been included in Section 7.2. Nalcor has not directly considered a sensitivity case to gauge the impact of CDM on the CPW

[8] NLH and Newfoundland Power*, Five-Year Energy Conservation Plan: 2008-2013*, 2008

for the Interconnected Island alternative because, in such an instance, NLH would have opportunities to monetize any conserved energy through short term sales into regional export markets.

2.6 2010 PLF Load Growth

Across the 20-year forecast horizon, the results of the 2010 long-term PLF projects a period of overall load growth for the Island Interconnected system. The compound annual growth rate between 2009 and 2029 is 1.3 percent.

Table 6: 2010 Planning Load Forecast Growth Rate Summary

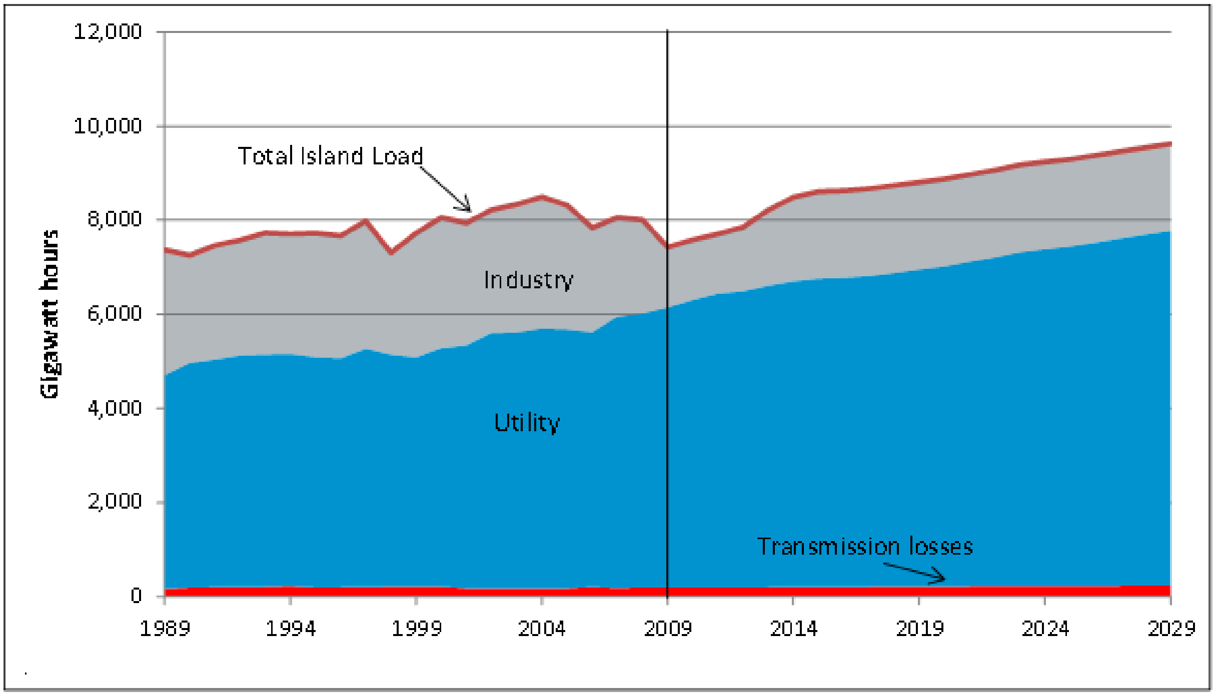
	Historical	Forecast		
Load Growth[1]	1999-2009	2009-2014	2009-2019	2009-2029
Island Utility	2.0%	1.8%	1.2%	1.2%
Island Industrial	-7.0%	7.1%	3.8%	1.9%
Island System	-0.4%	2.7%	1.7%	1.3%

1. Compound annual growth rates based on actual, non-weather normalized energy consumption.

Source: NLH, *Summary of Newfoundland and Labrador Hydro 2010 Long Term Planning Load Forecast*, 2010 (Exhibit 27)

The growth rates in Table 6 indicate that growth in utility load, as forecast in the 2010 PLF, will be lower in the next 20 years than experienced in the previous 20-year period with decelerating growth post 2014. Island industrial load growth is solely related to the construction and operation of the Vale nickel processing facility and offsets much of the decline in industrial load experienced in the 1999 to 2009 period. The island system growth rates reflect the combination of both utility and industrial loads. Figure 5 below illustrates the island load from 1990 to present and for the forecast period out to 2029.

Figure 5: Total Island Load (1989-2029)



Sources: (1)NLH, *Summary of Newfoundland and Labrador Hydro 2010 Long Term Planning Load Forecast,* 2010 (Exhibit 27)
(2)NLH, System Planning

2.7 Summary

The long-term load forecast was prepared on the basis of a set of underlying assumptions that NLH considers to be conservative. The provincial economic forecast provided by the province's Department of Finance has moderate growth expectations for the 20-year forecast period and assumptions with respect to petroleum pricing are based on price projections provided by a reputable international forecaster on such matters.

While the island's electricity requirements have declined recently due to structural changes within international pulp and paper markets, by 2015 continued growth of the island's utility demand, combined with the electricity requirements for Vale's nickel processing facility, will offset the decline experienced in island load.

Due to the uncertainty of achieving dependable firm outcomes, NLH has not explicitly accounted for the energy efficiency savings targets associated with the takeCHARGE program. However, CDM will continue to be an important initiative for NLH and NP.

The long-term Interconnected Island energy and demand requirements stemming from the 2010 PLF are subsequently used in the next step of the system planning process employed by NLH, that being the assessment of the adequacy of existing generation capacity. Sensitivity analyses that address different island load growth futures are discussed in Section 7.2.

3.0 System Planning Criteria and Need Identification

The section describes NLH's generation and transmission planning criteria along with the generation planning modeling framework and its input requirements. Then the needs analysis begins with an overview of the existing power system on the island and then quantifies the need and timing for new generation and transmission as a result of comparing the PLF from Section 2 with the existing power system capability.

3.1 Generation Planning Criteria

NLH has established criteria related to the appropriate reliability at the generation level for the island's electricity system which sets the timing of generation source additions. These criteria establish the minimum level of capacity and energy installed in the system to ensure an adequate supply to meet consumer firm requirements at the designated level of reliability, as indicated below. As a decision rule for NLH's planning activities the following generation planning criteria have been adopted:

> *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 to supply all of its firm energy requirements with firm system capability.

NLH calculates this using LOLH. LOLH is a probabilistic assessment of the risk that the electricity system will not be capable of serving the system's firm load for all hours of the year. For NLH, an LOLH expectation target of not more than 2.8 hours per year represents the inability to serve all firm load for no more than 2.8 hours in a given year.

Firm capability for the hydroelectric resources is the firm energy capability of those resources under the most adverse three-year sequence of reservoir inflows occurring within the historical record. Firm capability for the thermal resources (Holyrood Thermal

Generating Station) is based on energy capability adjusted for maintenance and forced outages.

NLH determines the need for additional capacity on the power system to ensure reliability of supply in case of an unplanned failure to generating units or other generation related system assets. Adequate reserve means that if such failures occur, additional generation is available on the system to ensure that NLH can continue to deliver the power consumers require, at the designated level of reliability.

The process for determining reserve capacity is a common approach used in the utility industry and has been reviewed and accepted by the Board[9].

Comparison to Other Canadian Utilities and NERC

Most utilities connected to the North American grid are members of a Regional Reliability Organization. All Regional Reliability Organizations in North America are under the jurisdiction of the North American Electric Reliability Corporation (NERC). NERC planning standards require each Regional Reliability Organization to conduct assessments of its resource and transmission adequacy. Consequently, many Regional Reliability Organizations have adopted an industry planning standard for generation reserve margins based on a loss of load duration, on a probabilistic basis, of one day every 10 years. This typically results in capacity reserve margins in the range of 15-20 percent, depending on the region. Canadian utilities/system operators that have interconnections with US counterparts are members of Regional Reliability Organizations, and as such, must follow the region's generation adequacy criteria as a minimum. 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.

Most utilities in North America have interconnections to the North American grid over which they can share generation reserve with their neighbours. The isolated island grid cannot depend on support from other utilities in times of emergency and therefore must supply all

[9] Quetta Inc. and Associates, *Technical Review of Newfoundland and Labrador Hydro, Final Report*, 1999

of its reserve. For NLH to apply an accepted reliability criteria of LOLH equivalent of one day in 10 years, additional generating capacity would have to be maintained, the cost of which would be included in NLH's rate base. For this reason a "one day in five year" criterion was adopted instead of the "one day in 10 years".

3.2 Transmission Planning Criteria

An integral part of the electric power system planning process involves the development of least cost technically viable transmission expansion plans to support the generation supply futures while adhering to a transmission planning criteria. The technical analysis required to develop viable transmission expansion plans utilizes the industry accepted standard for transmission planning software, *PSS®E* by Siemens PTI. *PSS®E* enables the transmission planner to perform steady state, short circuit and stability analyses on the transmission system to determine when established transmission planning criteria are violated and to test potential solutions to ensure the criteria are met in the future.

NLH follows traditional transmission planning practices similar to those found in the transmission planning standards for NERC. NLH's existing transmission planning criteria are summarized as follows:

- NLH's bulk transmission system is planned to be capable of sustaining the single contingency loss of any transmission element without loss of system stability.
- In the event a transmission element is out of service, power flow in all other elements of the power system should be at or below normal rating.
- The NLH system is planned to be able to sustain a successful single pole reclose for a line to ground fault based on the premise that all system generation is available.
- Transformer additions at all major terminal stations (i.e., two or more transformers per voltage class) are planned on the basis of being able to withstand the loss of the largest unit.

- For single transformer stations there is a back-up plan in place which utilizes NLH's and/or Newfoundland Power's mobile equipment to restore service.
- For normal operations, the system is planned on the basis that all voltages be maintained between 95 percent and 105 percent.
- For contingency or emergency situations voltages between 90 percent and 110 percent are considered acceptable.

The established NLH transmission planning criteria includes the requirement that for loss of a transmission line or power transformer that there be no loss of load. Given the Island Interconnected transmission system is electrically isolated from the North American grid, NLH transmission planning standards permit under frequency load shedding for loss of a generator. The provision of sufficient spinning reserve and increased system inertia for a loss of generation would be difficult to achieve and cost prohibitive for the island's relatively small rate base.

While the loss of a generator results in temporary loss of load through the under frequency load shedding scheme, the transmission planning process for the island grid considers the fact that the generator outage may be long-term, requiring the start-up of standby generation including the combustion turbines added by the generation planning process to meet the LOLH target. With the permanent generator outage and start-up of stand by generation, the transmission planning process must ensure there is sufficient transmission capacity to supply all load, including the load temporarily shed during the initial generator contingency.

3.3 *Strategist®*

Ventyx Strategist® is a software package used by NLH to enable decision-making once it has been determined that generation expansion is required to meet system demands. It is an integrated, strategic planning computer model that performs, amongst other functions, generation system reliability analysis, projection of costs simulation and generation expansion planning analysis. *Strategist®* is used by many utilities throughout the industry and has broad acceptance by regulatory bodies.

The software can analyze and plan the generation requirements of the system for a given load forecast and for specific parameters as identified by the utility that can include resource limitations, fuel prices, capital costs, and operating and maintenance costs (O&M). *Strategist®* evaluates all of the various combinations of resources and produces a number of generation expansion plans, including the least cost plan, to supply the load forecast within the context of the power system reliability criteria and other technical limitations as set by the utility.

3.4 Cumulative Present Worth (CPW)

Generation expansion planning and analysis provides the incremental production costing for all the operational and capital expenses necessary for NLH to reliably supply electricity to meet the forecasted requirements for power and energy over time. For each year of the extended planning period, the *Strategist®* software calculates NLH's production expenses given the configuration of thermal and renewable alternative resources in economic order at its disposal, power purchases from third parties, annual capital related expenses as new plants come on line, and O&M costs.

Strategist® calculates annual production- and capital-related costs estimates in nominal Canadian dollars for each year of the long-term planning period. To convert all future costs to a common present day period, a planning metric called Cumulative Present Worth is calculated. CPW is the present value of all incremental utility capital and operating costs incurred to reliably meet a specified load forecast given a prescribed set of reliability criteria. An alternative long-term supply future that has a lower CPW than another supply alternative will be the preferred investment strategy for the utility where all other constraints, such as access to capital, are satisfied. The selection of an alternative investment path with a lower CPW is consistent with the objective of providing least cost power because an alternative with a lower CPW results in an overall lower regulated revenue requirement from the customers served. Consistent with a discounted cash flow analysis, the CPW analysis likewise requires the selection of a discount rate to account for the time value of money. The discount rate has been set to match NLH's regulated average long run weighted cost of capital which, for the 2010 generation expansion analysis being reported herein, was eight percent.

3.5 Key Inputs to the *Strategist®* CPW Analysis

In preparing to carry out a generation expansion analysis using *Strategist®*, the inputs into the planning model are reviewed and updated as required. Key inputs and parameters are as follows:

Planning Load Forecast

This review utilizes the 2010 PLF as prepared by NLH System Planning Department and has been presented in detail in Section 2.

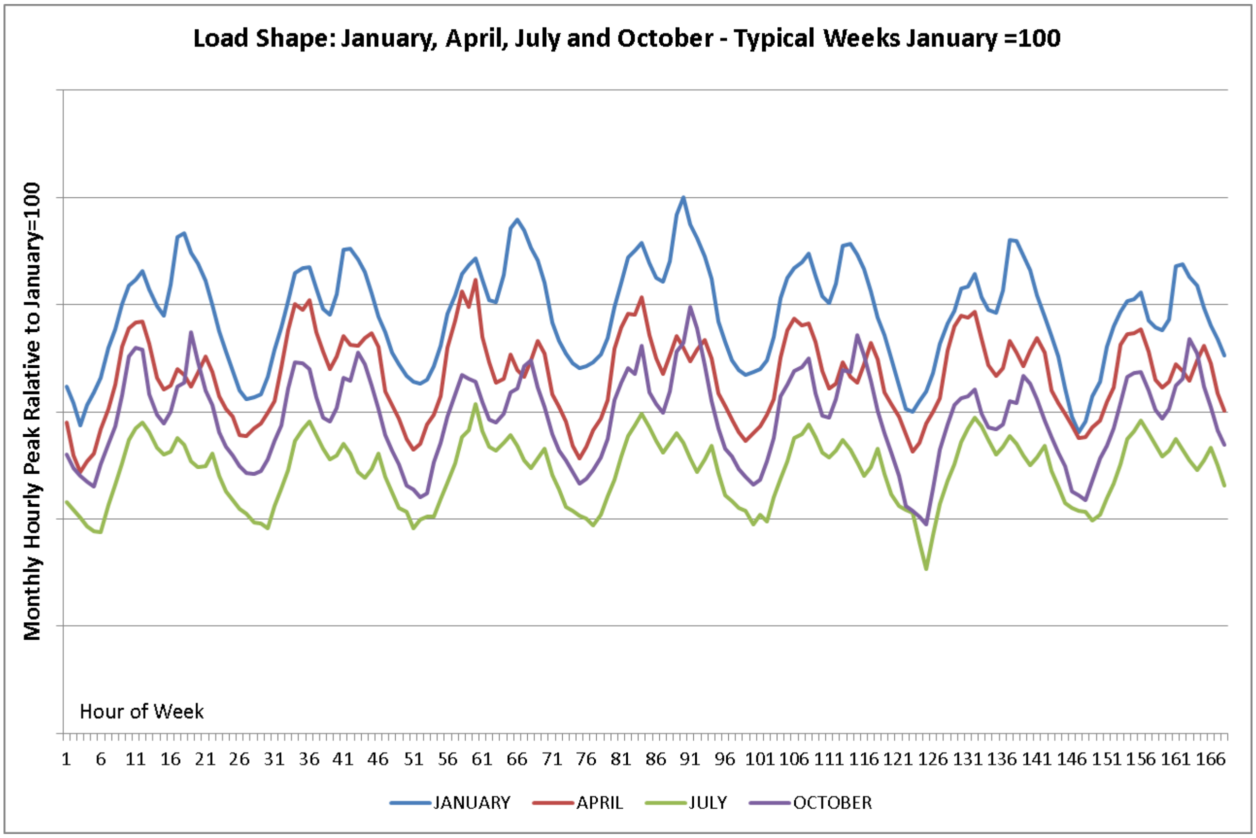
Time Period of Study

The time period that the study will cover must be defined and all other inputs must be developed to cover this period. The time period for the 2010 expansion analysis is 50 years after in service of the LIL in order to cover its service life. Thus the full period of analysis is from 2010 to 2067.

Load Shape

Hourly load shapes for each month of the year are required. NLH uses a representative week to model each month, with inputs based on hourly system load readings for the island grid. The applicable load shape illustrated for the week of the first month of each quarter is provided in Figure 6.

Figure 6: Load Shape Used in *Strategist®* CPW Analysis



Source: NLH, *Annual Load Shape*, 2011 (Exhibit 2)

Escalation Series

Escalation rates for capital and O&M costs are developed annually based on external projections received from the Conference Board of Canada and Global Insight. In addition to forecasts for general inflation and related O&M costs, escalation cost indices are developed for NLH primary construction projects in generation, transmission, and distribution. These composite indices represent a weighting by input construction cost item. Forecasts for Producer Price Indices (PPIs) regularly prepared by Global Insight are used to forecast each composite index. For the Lower Churchill Project separate construction project escalation indices have been developed for Muskrat Falls and the LIL[10]. The escalation rates used in the present analysis are provided in Table 7.

---

[10] Nalcor Energy, Cost Escalation Methodology Overview, 2011 (Exhibit 3 - Part 2)

Table 7: Inflation and Escalation Forecast Used in *Strategist®* CPW Analysis

	General Inflation 2009 = 1.000		Electric Utility Construction Price Escalation 2009 = 1.000						Lower Churchill Project 2010 = 1.000		Operating & Maintenance (O&M) 2009 = 1.000			
Year	GDP Implicit Price Deflator	Canadian CPI	CT Plant	CCCT Plant	Hydraulic Plant	Trans-mission Line	Trans-former Station	Distri-bution Line	MF	LIL	More Material Less Labour	Same Material Same Labour	More Labor Less Material	Labor Only
2000	0.825	0.835	0.776	0.763	0.765	0.829	0.873	0.846						
2001	0.834	0.856	0.784	0.773	0.785	0.836	0.894	0.851						
2002	0.843	0.875	0.804	0.792	0.798	0.849	0.911	0.857						
2003	0.871	0.899	0.813	0.798	0.807	0.845	0.884	0.858						
2004	0.899	0.915	0.827	0.812	0.842	0.875	0.894	0.861						
2005	0.930	0.935	0.858	0.850	0.863	0.885	0.910	0.877						
2006	0.953	0.954	0.894	0.884	0.891	0.923	0.935	0.936						
2007	0.983	0.975	0.922	0.913	0.913	0.941	0.949	0.957						
2008	1.021	0.997	0.973	0.967	0.971	1.003	0.981	0.991						
2009	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000			1.000	1.000	1.000	1.000
2010	1.024	1.022	0.982	0.984	0.991	0.993	0.988	0.993	1.000	1.000	1.022	1.025	1.028	1.030
2011	1.048	1.046	0.998	1.000	1.008	1.015	0.993	1.009	1.020	1.020	1.044	1.051	1.057	1.061
2012	1.071	1.069	1.020	1.020	1.028	1.042	1.003	1.029	1.050	1.040	1.067	1.077	1.087	1.093
2013	1.095	1.093	1.046	1.043	1.051	1.072	1.022	1.054	1.110	1.080	1.090	1.104	1.117	1.126
2014	1.118	1.116	1.081	1.074	1.080	1.111	1.051	1.079	1.160	1.120	1.114	1.132	1.148	1.160
2015	1.140	1.138	1.105	1.098	1.103	1.139	1.075	1.102	1.200	1.160	1.139	1.160	1.180	1.195
2016	1.163	1.161	1.108	1.103	1.106	1.141	1.086	1.120	1.230	1.200	1.164	1.189	1.213	1.231
2017	1.186	1.184	1.121	1.116	1.117	1.155	1.096	1.136	1.260	1.240	1.190	1.219	1.247	1.268
2018	1.210	1.208	1.140	1.135	1.134	1.176	1.110	1.154	1.300	1.290	1.216	1.249	1.282	1.306
2019	1.234	1.232	1.162	1.155	1.152	1.198	1.127	1.175			1.243	1.280	1.318	1.345
Post 2019 Annual % Change	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	NA	NA	2.2%	2.5%	2.8%	3.0%

Source: Nalcor Energy, *Nalcor Inflation and Escalation Forecast*, 2011 (Exhibit 3)

Heavy Fuel Oil and Distillate Market Prices

The PIRA Energy Group of New York, an international supplier of energy market analysis and forecasts, and oil market intelligence in particular, independently supplies the fuel oil price forecasts that are used for costing thermal fuel expenses for the provincial power system. These forecasts are updated for the most current long-term projections at the beginning of each generation planning expansion analysis. These market based fuel oil price forecasts are used in production costing for the existing Holyrood plant and simple cycle combustion turbine (CT) thermal plants, plus for any new combined cycle combustion turbines (CCCTs) or

CTs that would be constructed in future periods. The prices used in the 2010 CPW analysis are presented in Table 8, along with a long-term price update as of May 2011 that was included in the CPW sensitivity analysis in Section 7.2.

Table 8: Thermal Fuel Oil Price Forecast Used in *Strategist®* CPW Analysis

	Reference Forecast at Jan 2010			Reference Forecast at May 2011		
Year	#6 0.7%s ($Cdn/bbl)	#6 2.2%s ($Cdn/bbl)	Diesel ($Cdn/l)	#6 0.7%s ($Cdn/bbl)	#6 2.2%s ($Cdn/bbl)	Diesel ($Cdn/l)
2010	81.30	79.60	0.674			
2011	83.20	80.50	0.700	102.90	95.70	0.908
2012	90.90	88.00	0.760	118.40	113.70	0.990
2013	98.80	95.50	0.815	122.50	119.20	1.025
2014	102.60	99.00	0.850	126.90	123.40	1.060
2015	106.80	103.00	0.905	130.80	127.10	1.100
2016	111.10	107.00	0.945	135.60	131.60	1.140
2017	116.30	111.50	0.990	140.70	136.00	1.180
2018	121.10	115.60	1.030	144.30	139.00	1.210
2019	124.90	118.60	1.065	147.90	141.80	1.240
2020	129.20	120.30	1.100	151.50	142.80	1.275
2021	132.80	123.10	1.155	153.60	144.20	1.315
2022	136.00	125.80	1.195	155.50	145.80	1.350
2023	139.10	128.50	1.235	157.80	147.70	1.385
2024	142.10	131.10	1.275	160.70	150.20	1.425
2025	145.00	133.70	1.315	162.80	152.00	1.460

Notes: (1) Product prices reflect landed values on Avalon Peninsula.
(2) Diesel represents No. 2 distillate gas turbine fuel fob Holyrood.
(3) Post 2025 pricing is forecast at annual inflation of 2%.

Sources: (1) Nalcor Energy/ NLH, *Thermal Fuel Oil Price Forecast: Reference as of January 2010* (Exhibit 4)
(2) Nalcor response to MHI-Nalcor-126

Weighted Average Cost of Capital /Discount Rate

The generation expansion analysis for 2010 used a weighted average cost of capital (WACC) for new capital assets of 8.0 percent consistent with NLH regulated utility WACC assumptions prepared as of January 2010. The WACC reflects a targeted debt: equity ratio of 75 percent for NLH regulated operations, comprised of a forecasted long-term cost of debt at 7.3 percent and a long-term cost of equity at 10 percent. All monetary costs were modeled in current (as spent) Canadian dollars and present valued to 2010$ at the defined discount rate of 8.0 percent.

Capital Cost Estimates

Capital costs estimates for the portfolio of alternative generation assets are based on formal feasibility studies and estimates as developed by consultants and NLH's Project Execution and Technical Services Division. The portfolio of utility projects used in the 2010 generation expansion analysis is provided in Table 9.

Table 9: Portfolio of Utility Projects Used in Strategist® CPW Analysis

Facility	2010$, millions	In-Service Capital Cost Including Escalation and AFUDC/IDC For Isolated and Interconnected Alternatives
Island Pond	$166	$199 million in 2015
Portland Creek	$90	$111 million in 2018, $156 million in 2036
Round Pond	$142	$185 million in 2029
Wind 2 X 27 (new)	$125	$189 to $281 million, various in-service years
Wind 1 x 25 (new)	$58	$98 to $146 million, various in-service dates
Greenfield CCCT #1	$274	$465 to $882 million, various in-service years
Greenfield CCCT #2	$206	$346 to $644 million, various in-service dates
CTs New	$65	$75 to $209 million, various in-service years
Holyrood FGD and ESP	$458*	$582 million in 2015
Labrador Island Transmission	$1,616	$2,553 million. 75:25 debt equity financing assumption

* 2009$
IDC: Interest During Construction

Sources: (1) Nalcor Energy, *Cashflow Calculations for 2010 Generation Expansion Studies*, 2010 (Exhibit 5)
(2) SNC-Lavalin Inc., *Studies for Island Pond Hydroelectric Project*, 2006 (Exhibit 5B)
(3) SNC Lavalin Inc., *Feasibility Study Round Pond Development*, 1989 (Exhibit 5D[i])
(4) Nalcor Energy, *October 2010 Capital Cost Update – Muskrat Falls HVdc Link*, 2010 (Exhibit 5E)
(5) Nalcor Energy, *Muskrat Falls Capex 15% Contingency – Quarterly Capex Summary*, 2010 (Exhibit 5F)
(6) Aces International Limited, *Holyrood Combined Cycle Plant Study Update*, 2001 (Exhibit 5H)
(7) Stantec Consulting Ltd., *Precipitator and Scrubber Installation Study HTGS*, 2008 (Exhibit 5L[i])
(8) NLH, *2010 PLF Strategist® Generation Expansion Plans*, 2010 (Exhibit 14 Rev. 1)
(9) SGE Acres limited, *Air Emissions Control Assessment-Holyrood Thermal Generating Station, Final Report*, 2004 (Exhibit 68)
(10) Nalcor response to MHI-Nalcor-1 (see detail in Exhibit 99)
(11) NLH, *Newfoundland and Labrador Hydro Generation Expansion Analysis, 2010 Island Isolated and Infeed Scenarios*, 2011 (Exhibit 99)
(12) Nalcor response to MHI-Nalcor-49.3 (AFUDC and escalation)
(13) Hatch, *CCGT Capital Cost Benchmark Study Final Report*, 2008 (Exhibit CE-46)
(14) NLH, *PUB Letter July 12 Q4b 50 MW Gas Turbine Budget Estimate Update*, 2011 (Exhibit CE-47)
(15) SNC-Lavalin Inc., *Feasibility Study for the Portland Creek Hydroelectric Project*, 2007 (Exhibit CE-49)
(16) Nalcor Energy, *Muskrat Falls Generation Facility and Labrador – Island Transmission Link: Overview of Decision Gate 2 Capital Cost and Schedule Estimates*, 2011 (Exhibit CE-51)
(17) SNC-Lavalin Inc., *Feasibility Study of HTGS Units 1&2 Conversion to Synchronous Condenser - An Evaluation of Run Up Options for Generators,* 2011 (Exhibit CE-56)
(18) SNC-Lavalin Inc., *Island Pond Hydroelectric Project Final Report, Appendix A - Capital Cost Estimates Back-Up*, 2008 (Exhibit CE-57)

<u>Power Purchase Agreements (PPAs)</u>

The annual power purchase expense incurred by NLH under existing PPAs and future PPAs are projected for input to *Strategist®* and are summarized in Table 10.

Table 10: PPAs Used in *Strategist®* CPW Analysis

PPA	GWh per Year	End Date	Comment
Fermeuse Wind	84	2028	Re-investment by NLH assumed if Isolated Alternative
St. Lawrence Wind	105	2028	Re-investment by NLH assumed if Isolated Alternative
3rd Wind Farm	88	2034	Isolated Alternative only. NLH re-investment assumed
Corner Brook Co-Gen	65	2023	
Rattle Brook (hydro)	14	Continuous	
Star Lake (hydro)	144	Continuous	
Exploits Partnership (hydro)	137	Continuous	
Exploits Generation (hydro)	480	Continuous	
Muskrat Falls	Max 4.9TWh	Continuous	See commentary below on pricing

Sources: (1) Nalcor Energy, *Hydro PPA Details*, 2011 (Exhibit 6)
(2) Nalcor response to MHI-Nalcor-49.2

<u>Muskrat Falls Power Purchase Expense</u>

The price that NLH pays for power and energy from Muskrat Falls on behalf of island ratepayers is a cornerstone for the Lower Churchill Project. Nalcor, in consultation with its financial advisors, has approached the issue of electricity pricing for the Muskrat Falls hydroelectric facility in a manner structured to achieve certain ratepayer benefits while still facilitating project development.

Under a regulated Cost of Service (COS) price setting environment, the annual revenue requirement for a utility asset would be comprised of:

COS = O&M Costs + Power Purchases+ Fuel + Depreciation + Return on Rate Base,

where Return on Rate Base would be comprised of a cost component for lenders (cost of debt) and a profit component for shareholders (return on equity) for a prescribed debt-equity capital structure. This annual COS would then be divided by the output produced and sold from the asset in question to derive an average selling price or rate (such as cents per kilowatt hour (kWh), or equivalent dollars per megawatt hour (MWh). An important feature of this pricing methodology is that under COS price setting, the unit rate revenue paid by ratepayers for a given asset is highest in the first year. This is because as a new regulated asset goes into rate base, the undepreciated cost of the asset is at its maximum and return on rate base is driven by undepreciated net book value. Another feature of this pricing framework is that as the equity investor earns its regulated return each year, the return in dollars is also highest in the first and initial years. This is not necessarily prudent for the Muskrat Falls development in that the island ratepayer energy requirements at the time of plant commissioning is projected to be only about 40 percent, or two terawatt hours (TWh), of the plant's average annual production of 4.9 TWh. While the island's energy requirements increase over time in line with economic growth, the early-year COS rate for Muskrat Falls power would be a significant burden for ratepayers in those years. The required COS revenue for Muskrat Falls would be at its maximum and the power required by ratepayers at a minimum. In an effort to address this issue, an alternative approach to Muskrat Falls power pricing was developed that affords a number of advantages for ratepayers.

To derive an appropriate price for NLH's power purchase requirements for the island, Nalcor undertook a supply pricing analysis for Muskrat Falls initially assuming that the total firm annual plant production was available for sale. The objective of this analysis was to determine the economic price for the project, in this instance expressed as an "escalating supply price"[11]. The escalating supply price is the price per MWh that recovers all costs associated with the Muskrat Falls hydroelectric development – operating and other incurred costs over time, debt service costs for the debt portion of the capital investment (as applicable) and a hurdle return on the equity portion of the capital investment. This escalating supply price is lower than would be indicated initially by the COS framework.

[11] It is perhaps more common in economic analysis to express economic supply prices as Levelized Unit Energy Costs, or LUECs. In either circumstance, the annual price, when multiplied by output and discounted, equals the present value of the project's costs given the capital and operating costs, other incurred expenses, and the cost and terms of obtaining capital.

Though it escalates evenly over time, the burden on ratepayers in the critical early years is minimized. This is accomplished essentially through the equity investor's flexibility on the timing of its equity return in the early years, relative to that in later years. Nalcor has calculated this escalating supply price for Muskrat Falls power based on the project's cost estimates at the time of Decision Gate 2 (DG2), coupled with an Internal Rate of Return (IRR) of 11 percent[12], to be approximately $76 /MWh in 2010$, escalating at two percent annually.

For the next step in the Muskrat Falls pricing analysis, this $76 /MWh escalating supply price was then used to calculate the revenues, cash flows, and shareholder returns assuming that the only market for Muskrat Falls output was the island market. The reduction in the volume of sales assuming only the island market, as outlined above, as opposed to full annual production quantities at start up, reduced the Muskrat Falls project IRR from 11 percent to 8.4 percent. Nalcor deemed this IRR to be acceptable for a case in which only island sales are available to Muskrat Falls, and adopted this escalating supply price framework for the present analysis. This return on equity is consistent with the present day return on equity for Newfoundland Power, and is only slightly below the long-run projected average for Newfoundland and Labrador electrical utilities. Nalcor considers this acceptable because Muskrat Falls may have opportunities for additional revenues over and above those from the island market, notably for the earlier part of the operational period before island demand fully subscribes Muskrat Falls output.

In addition to lower prices for ratepayers for Muskrat Falls power in the early years, a further advantage to this pricing approach rests with fixing the real dollar level for the Muskrat Falls supply price across time. Hydroelectric assets are very long life assets and where a power purchase price for its output is fixed in 2010$ constant real dollars, this helps to address intergenerational equity issues associated with large public investments in durable assets in the power sector – particularly as the full output of Muskrat Falls is not required by ratepayers in the early years of the project.

[12] The IRR was on firm power, with a 12% IRR on average power taken as an analytical benchmark for analysis purposes.

<u>Service Life/Retirements</u>

The service life and retirement dates for existing and new generation assets must be defined for the *Strategist®* expansion analysis as thermal plant replacement is an important component of generation planning and costing. The service life assumptions used in the present analysis provided in Table 11.

Table 11: Asset Service Life Assumptions Used in *Strategist®* CPW Analysis

Facility	Service Lives for Existing and Future NLH Generation Plant and Transmission – Retirement Dates	
	Isolated Island	Interconnected Island
Existing		
Holyrood Units 1 and 2	2033	2021*
Holyrood 3	2036	2021*
Hardwoods CT	2022	2022
Stephenville CT	2024	2024
Hydroelectric	perpetuity	perpetuity
Future		
Wind Farms	20 years	
Hydroelectric	perpetuity	
Labrador Island Link		50 years
CCCTs	30 years	
CTs	25 years	
* In the Interconnected Island alternative, the Holyrood units are retired before their targeted end of service lives.		

Source: NLH, *Retirements – Existing Units*, 2011 (Exhibit 7)

<u>Operating and Maintenance (O&M) Costs</u>

Non-fuel O&M costs for the resource projects are derived from feasibility studies and NLH's extensive operating experience. These O&M costs are comprised of fixed expenditures related to asset maintenance and variable costs driven by production output. The O&M assumptions are provided in Table 12.

Table 12: O&M Assumptions Used in Strategist® CPW Analysis

Facility	Fixed Annual O&M Cost $/kW (2010$)	Variable O&M Cost $ /kWh (2010$)
Island Pond	$15.79	NA
Portland Creek	$17.97	NA
Round Pond	$20.66	NA
Wind (new)	$28.89	$5.90
Holyrood CCCT	$9.22	$5.32
Greenfield CCCT #1	$10.49	$5.32
Greenfield CCCT #2	$9.22	$5.32
Holyrood Existing 3 Units	$41.39	$1.28
CTs Existing	$9.11	NA
CTs New	$10.49	$5.32
Holyrood FGD and ESP	$11 million (2015) to $24 million (2033) nominal	
Muskrat Falls	$13 million (2018) to $46 million (2067) nominal	
Labrador Island Transmission	$14 million (2017) to $50 million (2067) nominal	

Source: Nalcor Energy, *Operating Cost Estimates*, 2010 (Exhibit 8)

<u>Thermal Heat Rates</u>

Per unit fuel consumption of existing and future thermal generation sources are important inputs in production costing. The heat rates utilized in *Strategist®* reflect a combination of NLH's operating experience, plus external studies and estimates. The heat rates are listed in Table 13.

Table 13: Heat Rates Used in *Strategist®* CPW Analysis

Facility	Fuel Source	Maximum MBTU per MWh	Minimum MBTU per MWh
Existing Holyrood Units	No. 6	9.78	10.39
Existing CTs	No. 2	12.26	12.26
Existing Diesel Units	No. 2	10.97	10.97
Future CCCTs	No. 2	7.64	8.63
Future CTs	No. 2	9.43	9.43
MBTU: Millions of British Thermal Units			

Source: NLH, *Thermal Units – Average Heat Rates*, 2011 (Exhibit 9 Rev. 1)

Generation Capacity and Energy Capability - Existing and Future Resources

The monthly and annual average and firm energy production forecasts for all of the existing hydroelectric plants and wind farms are updated to incorporate the latest historical data and operational factors. Production forecasts from new thermal and renewable plants are based on engineering studies estimates.

Table 14: Existing and Future Generating Capacity Used in *Strategist®* CPW Analysis

Source	Net Capacity (MW)	Firm Energy (GWh)	Average Energy (GWh)
Existing Island Grid			
NLH Hydroelectric	927	3,961	4,510
NLH Thermal	590	2,996	2,996
Customer Owned	262	1,117	1,307
Non Utility Generators	179	879	1,030
Total Existing	**1,958**	**8,953**	**9,843**
Future Resources			
Island Pond	36	172	186
Portland Creek	23	99	142
Round Pond	18	108	139
Wind Farm	25	70 to 110	
CCCT	170	1,340	NA
CT	50	394	NA
Muskrat Falls	824	4,540	4,910
Labrador Island Link	900	NA	NA

Sources: 1) NLH, *Generation Planning Issues 2010 July Update*, 2010 (Exhibit 16)
2) Muskrat Falls firm and average as per LCP for modeling use.

Asset Maintenance Scheduling

Specific outage schedules to accommodate annual maintenance for each existing and future thermal generation asset must be included in the *Strategist®* analysis. Such maintenance scheduling is largely based on NLH's operational experience and asset management planning processes.

Table 15: Asset Maintenance Scheduling Used in *Strategist®* CPW Analysis

Facility	Weeks for Asset Maintenance	Period
Holyrood Units (3)	8 weeks each staggered across off–peak months	May/June, July/Aug, Sept/Oct
All Other Thermal	2 weeks each	April through November
All Hydroelectric	Maintenance assumed to be undertaken in off–peak months (Apr to Nov)	
Labrador Island Link	Maintenance assumed to be undertaken in off–peak months (Apr to Nov)	

Source: NLH, *Asset Maintenance Scheduling*, 2011 (Exhibit 11)

Forced Outage Rates

All generation production units have an associated involuntary forced outage rate leading to the unavailability of a generating unit. The forced outage rates used in this analysis are based on NLH's operating experience and/or industry norms as tabulated by the Canadian Electricity Association.

Table 16: Forced Outage Rates Used in *Strategist®* CPW Analysis

NLH Facility	Forced Outage Rate (%)
Combustion Turbine	10.62
Holyrood Thermal	9.64
Combined Cycle Thermal	5.00
Diesel	1.18
Existing and New Hydroelectric	0.90
Labrador Island Link (per pole)	0.89

Source: NLH, *Forced Outage Rates Summary Sheets*, 2011 (Exhibit 12)

Environmental Externalities

No environmental externality cost of carbon for carbon dioxide (CO_2) atmospheric emissions associated with thermal electric production has been included in production costing for thermal plants. It was also not included in subsequent CPW analysis, owing to prevailing uncertainties regarding the timing, scope, and design associated with future regulatory initiatives in this regard. The impact for this important thermal environmental cost item has been addressed in the sensitivity analysis in Section 7.2.

3.6 Needs Analysis

3.6.1 System Capability

NLH operates an interconnected generation and transmission system, or grid, on the island portion of the province. The island grid is isolated from the interconnected North American grid and, as a result, must be self-sufficient with respect to generation supply and transmission capability.

Island Grid Generation

Within the Isolated Island grid, NLH operates six hydroelectric generating stations, three mini-hydroelectric generating stations, one oil fired thermal generating station, three combustion turbines and two diesel plants. At 592 MW of installed capacity, the Bay d'Espoir Generating Station is the largest hydroelectric plant on the island. Combined with hydroelectric plants upstream at Upper Salmon and Granite Canal, the Bay d'Espoir reservoir system has an installed capacity of 717 MW and a firm energy capability of 2,955 GWh annually. Hydroelectric plants at Cat Arm, Hinds Lake and Paradise River, along with mini-hydro plants at Roddickton, Snook's Arm and Venom's Bight bring NLH's hydroelectric generating capacity in the island to 927.3 MW with a firm energy capability to 3,961 GWh annually. The 466 MW (net) oil fired thermal Holyrood Generating Station is located in the municipality of Holyrood has a firm energy capability of 2,996 GWh annually. The Holyrood plant plays an essential role in the island's power system in providing critical firm supply as it represents approximately one third of NLH's existing generating capability. The plant is required to supply the island system peak load requirements from October to May with the number of units operating varying with the amount of customer demand in each month. All three units normally operate during the highest demand months of December to March. The total energy production and the plant operating factor can vary significantly from year to year depending primarily on the amount of hydraulic production during the year, weather conditions impacting utility load, and by industrial production requirements.

Table 17 provides an overview of the historical production and fuel related statistics for the Holyrood plant since 2000.

Table 17: Holyrood Thermal Production and Heavy Fuel Oil Consumption

Year	Net Production (GWh)	Heavy Fuel Oil (Millions Barrels)	Operating Factor (%)	Annual Fuel Cost ($ Millions)	Holyrood Fuel Expense as a % of Island Revenue Requirement
2000	970.3	1.60	24%	49.4	19%
2001	2,098.5	3.32	51%	98.5	32%
2002	2,385.3	3.68	58%	112.5	36%
2003	1,952.0	3.07	48%	114.8	36%
2004	1,647.6	2.61	40%	80.8	26%
2005	1,328.6	2.14	33%	80.3	26%
2006	740.3	1.26	18%	63.5	22%
2007	1,255.6	2.04	31%	107.4	31%
2008	1,080.2	1.73	26%	123.7	34%
2009	939.9	1.53	23%	80.6	24%
2010	803.1	1.36	20%	100.6	29%

Sources: (1) NLH, *General Ledger Annual Bunker Summary*
(2) NLH, Rates Department

The recent shutdown of Abitibi's two newsprint mills on the island, and cutbacks at Corner Brook Pulp and Paper, has resulted in a decline in the total island energy requirements. This has resulted in a reduction in the quantity of energy produced from the Holyrood plant. However, going forward, almost all incremental load growth, and in particular the addition the addition of Vale's large industrial load for its nickel processing facility in Long Harbour will cause output at the Holyrood plant to materially increase to previous historical levels, and beyond. The Long Harbour facility will, itself, require the consumption of about an additional one million barrels of heavy fuel oil at the Holyrood plant each and every year.

As a thermal electric production facility using heavy fuel oil, the Holyrood plant is a large source of atmospheric pollution emissions in the province. Atmospheric pollution emissions at the Holyrood plant vary with production. As energy production increases for the reasons outlined above, atmospheric emission will increase. Table 18 provides the emissions at the Holyrood plant since 2000.

Table 18: Atmospheric Emissions at the Holyrood Plant (tonnes)

Year	Carbon Dioxide (CO_2)	Sulphur Dioxide (SO_2)	Nitrous Oxide (NOx)	Particulate Matter (PM)
2000	799,546	10,268	1,733	988
2001	1,636,930	20,784	3,893	2,059
2002	1,817,499	23,235	4,553	2,294
2003	1,518,955	19,551	3,805	1,918
2004	1,290,828	16,819	3,239	780
2005	1,062,231	13,648	2,792	1,374
2006	625,084	5,370	1,710	564
2007	1,012,280	6,234	2,489	551
2008	861,891	4,880	2,077	345
2009	769,209	3,937	1,819	211
2010	677,729	2,994	1,648	216
Note – Since 2006 lower emissions have been related to the use of lower sulphur fuel oil in addition to reduced output.				

Source: NLH, *Annual Air Emissions Report*

In addition to its own generating capability, NLH has power purchase agreements (PPAs) with a number of non-utility generators including two 27 MW wind farms. The combined capability of these PPAs is 178.8 MW with a firm energy capability of 879 GWh annually.

Both Newfoundland Power and Corner Brook Pulp and Paper have generating facilities on the Isolated Island System which total 261.5 MW with a firm energy capability of 1,117 GWh annually.

Island Grid Generation Capability

The total interconnected generation capability from all sources on the existing Isolated Island System is 1,958 MW with a firm and average energy capability of 8,953 GWh and 9,843 respectively. Table 19 provides a listing of the island's generation capability.

Table 19: Island Grid Generation Capability

Existing Island Grid	Net Capacity (MW)	Firm Energy (GWh)	Average Energy (GWh)
NLH Hydroelectric	927	3,961	4,510
NLH Thermal	590	2,996	2,996
Newfoundland Power	140	324	428
Corner Brook Pulp and Paper	121	793	879
Star Lake - Exploits	106	634	761
Non Utility Generators	73	245	269
Total Existing	**1,958**	**8,953**	**9,843**

Source: NLH, *Generation Planning Issues July 2010 Update*, 2010 (Exhibit 16)

Island Grid Transmission

NLH has a total of 54 high voltage terminal stations and 3,473 km of high voltage transmission lines operating at voltages levels of 230 kV, 138 kV, and 66/69 kV connecting generating stations to NLH customers including Newfoundland Power, industrial customers and NLH's own rural distribution customers.

NLH's largest bulk transmission system on the island grid consists of 1,608 km of 230 kV transmission line stretching from Stephenville in the west to St. John's in the east, connecting generating stations with major load centers. Below the 230 kV system, NLH operates a 138 kV transmission loop between Deer Lake and Stony Brook (near Grand Falls-Windsor) and delivers power and energy to Newfoundland Power at Stony Brook, Sunnyside, Western Avalon and Holyrood for its Stony Brook to Sunnyside and Western Avalon to Holyrood 138 kV loops. These 138 kV loops, connected between two points on the 230 kV bulk system, provide power and energy to geographic regions where the total load of the connected communities fall in the 75 MW to 225 MW range.

Beyond the 138 kV loops, NLH operates a number of radial transmission lines at 138 kV and 66/69 kV voltage levels to supply more rural and smaller industrial loads that are remote for the 230 kV bulk system, such as customers on the Great Northern Peninsula, the Connaigre Peninsula, White Bay and the Duck Pond Mine. Generally, the loads on the NLH radial systems are in the five MW to 35 MW range.

At the NLH customer level, Newfoundland Power operates a number of 138 kV and 66 kV transmission lines within the Island grid. Newfoundland Power lines are generally used to connect NLH bulk delivery points to NP customers and generating stations.

Corner Brook Pulp and Paper operates a 66 kV transmission system between its hydroelectric facilities at Deer Lake and Watson's Brook and the mill in Corner Brook.

3.7 Identification of Need for Generation

Table 20 provides a summary of the 2010 PLF electric power and energy requirements for the system period 2010 to 2029 compared against supply capacity and firm capability to determine the timing and need for new generation resources. For the Isolated Island system, capacity deficits commence in 2015, with firm energy deficits commencing in 2021. Capacity deficits trigger the need for the next generation source by 2015.

Table 20: Capacity and Energy Balance and Deficits for 2010 PLF (2010-2029)

Year	Island Load Forecast		Existing System			
	Maximum Demand (MW)	Firm Energy (GWh)	Installed Net Capacity (MW)	Firm Capability (GWh)	LOLH (hr/year) (limit: 2.8)	Energy Balance (GWh)
2010	1,519	7,585	1,958	8,953	0.15	1,368
2011	1,538	7,709	1,958	8,953	0.22	1,244
2012	1,571	7,849	1,958	8,953	0.41	1,104
2013	1,601	8,211	1,958	8,953	0.84	742
2014	1,666	8,485	1,958	8,953	2.52	468
2015	1,683	8,606	1,958	8,953	3.41	347
2016	1,695	8,623	1,958	8,953	3.91	330
2017	1,704	8,663	1,958	8,953	4.55	290
2018	1,714	8,732	1,958	8,953	5.38	221
2019	1,729	8,803	1,958	8,953	6.70	150
2020	1,744	8,869	1,958	8,953	8.05	84
2021	1,757	8,965	1,958	8,953	10.14	(12)
2022	1,776	9,062	1,958	8,953	13.05	(109)
2023	1,794	9,169	1,958	8,953	16.75	(216)
2024	1,813	9,232	1,958	8,953	19.94	(279)
2025	1,827	9,290	1,958	8,953	25.76	(337)
2026	1,840	9,372	1,958	8,953	29.92	(419)
2027	1,856	9,461	1,958	8,953	35.57	(508)
2028	1,872	9,543	1,958	8,953	42.35	(590)
2029	1,888	9,623	1,958	8,953	50.71	(670)

Source: NLH, *Generation Planning Issues, July 2010* (Exhibit 16)

Without new supply, by 2015 demand will increase to a point where additional generation is required to maintain an appropriate generation reserve for the forecast peak demand. Otherwise NLH's reserve capacity will have fallen below the established minimum level standard of 2.8 LOLH to ensure a continuing reliable supply of electricity to meet electricity demand on the island in the event of system contingencies. In other words, without additional generation in 2015 NLH will violate its generation planning criteria.

As load continues to grow, the island will experience an energy deficit by 2021 if no additional generation capability is added. This deficit will occur when the island's overall electricity requirements are greater than the combined firm energy capability of NLH's thermal and hydroelectric generation plants.

3.8 Identification of Need for Transmission

As part of the regular system planning process, NLH completes a review of the transmission system to assess its adequacy. The Island Transmission System Outlook Report[13] provides an overview of the transmission system requirements in the five to 10 year time frame. Given the identified need for new generation supply in the near term, the report offers the following important transmission issues that must be considered when new generation sources are added to the island system:

- The 230 kV transmission system east of Bay d'Espoir is both thermally and voltage constrained with respect to increasing power deliveries to the Avalon Peninsula load center;
- New generation sites off the Avalon Peninsula will require addition 230 kV transmission line reinforcement along the Bay d'Espoir to St John's corridor; and
- The 230 kV transmission system west of Bay d'Espoir experiences high voltage levels during the year, which may impact generator ratings for new generation sources in this part of the system.

[13] NLH, *Island Transmission System Outlook*, 2010 (Exhibit 24)

Following development of generation expansion plans through the generation planning process, the transmission system impacts of the proposed generation sites can be more fully assessed and transmission system additions more fully defined.

3.9 Summary

Following a review of generation and transmission planning criteria, the *Strategist®* modelling framework, and the existing island grid's generation capability, a need for new generation supply has been identified for capacity and energy in 2015 and 2021 respectively. Given the need for generation additions, the Island Transmission System Outlook Report identifies potential areas of concern that must be addressed under the transmission planning criteria once the generation expansion plans are developed.

A decision was made in 2010 as to what new generation source would be selected to allow sufficient time to bring generation and related infrastructure on line in time.

4.0 Identification of Alternatives and Phase 1 Screening

This section presents a summary of the power generation supply options for both the Isolated Island and Interconnected Island alternatives. It represents a portfolio of electricity supply options that could be theoretically considered to meet future generation expansion requirements for the island of Newfoundland. These individual supply options represent a range of choices/alternatives from local indigenous resources, to importing energy fuels from world energy markets, to interconnecting with regional North American electricity markets.

Specific supply options are initially considered and screened based on initial screening principles that align with Nalcor's/NLH's mandate. The initial screening is important as it enables NLH to concentrate further consideration on only the technologies and alternatives that offer the highest potential to ensure effective expenditures of ratepayers' money. In addition prudent pricing assumptions are essential for fuel based generation alternatives.Those options that remain following the high level screening are input into the generation planning software models for further analysis and ultimately for the recommendation of the preferred generation expansion plan.

4.1 Screening Principles

Security of Supply and Reliability

Security of supply and reliability are the two most important criteria for evaluating the supply investment decision.

NLH is mandated to provide reliable least cost electrical supply to the people of the province. As part of its mandate, NLH must maintain a long-term plan that demonstrates its ability to continue to supply the expected requirements. A realistic plan is particularly important for the island portion of the province as it is isolated from the rest of the North American electrical grid and cannot rely on support from neighbouring jurisdictions should there be problems because of the application of unreliable technologies.

Because of the importance of having a realistic plan, NLH has developed an Isolated Island expansion plan that is a least cost optimization utilizing only proven technologies to ensure they can meet the required expectations from security of supply, reliability, and operational perspectives. There must be a high level of certainty that all elements of the Isolated Island alternative plan can be permitted, constructed and integrated successfully with existing operations. Generation technologies that do not meet these rigorous requirements are excluded from further consideration.

Cost to Ratepayers

NLH's mandate, as defined in Section 3(b) of the *Electrical Power Control Act, 1994*[14], is to ensure that all sources and facilities for the production, transmission and distribution of power in the province should be managed and operated in the most efficient manner such that power delivered to consumers in the province is at the lowest possible cost consistent with reliable service. Least cost for ratepayers is a key objective of the company and guides its business decisions, expansion plans and overall strategic direction.

Environmental Considerations

Environmental stewardship is one of Nalcor's guiding principles. This principle is also embodied in *Focusing Our Energy: Newfoundland and Labrador Energy Plan*[15] (the Energy Plan) and provides guidance to Nalcor in making investment decisions. The company must meet any current environmental regulations laid out in both provincial and federal legislation and also must consider potential new environmental legislation due to the longer term nature of its generation expansion decisions. The company must also adhere to any provincial policy provided in this regard.

[14] Government of Newfoundland and Labrador, *An Act to Regulate the Electrical Power Resources of Newfoundland And Labrador 1994,* 1994
http://www.assembly.nl.ca/legislation/sr/statutes/e05-1.htm

[15] Government of Newfoundland and Labrador*, Focusing Our Energy: Newfoundland and Labrador Energy Plan*, 2007
http://www.nr.gov.nl.ca/nr/energy/plan/index.html

Risk and Uncertainty

Given the magnitude of the decisions being undertaken for generation expansion and the expenditures proposed, risk and uncertainty are key decision criteria. Nalcor considers this in its investment decision-making.

Financial Viability of Non-Regulated Elements

Consideration of financial viability is important to ensure that the shareholder makes an adequate rate of return and any project investment can obtain debt financing and can meet debt repayment obligations.

4.2 Generation Alternatives

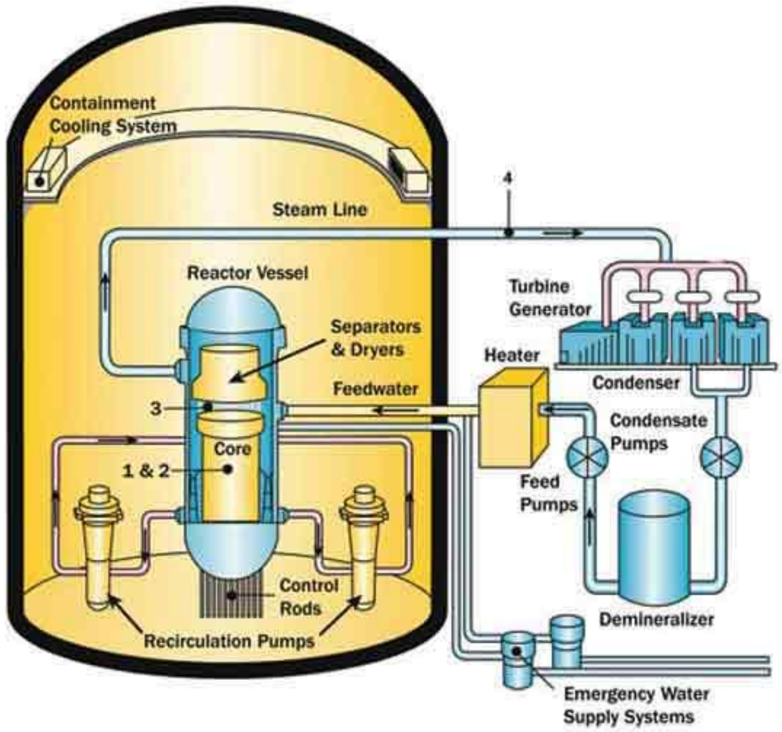
Several generation alternatives were reviewed and considered for potential use in the generation expansion plans. A summary of each of those alternatives and whether they were screened out or included in the analysis follows.

4.2.1 Nuclear

A nuclear reactor uses controlled nuclear reactions to produce heat energy. The heat energy is then used to produce steam. The steam is used to turn a steam turbine, which turns an electric generator to produce electricity.

A nuclear power generation plant would not integrate well into the Isolated Island system due to the fact that the nuclear plant must operate at a base load with very little output change. Nuclear plants do not ramp up or down very well, or quickly. Therefore a nuclear generator would function well in the Isolated system where daily load changes are on the order of 400 MW. Furthermore, as most new designs are in the 1,000 MW range, they are sized far greater than the Isolated system's minimum load of approximately 400 MW. With an inability to follow the Isolated Island load pattern, a nuclear generator would be forced off for large portions of the year.

Figure 7: Components of a Typical Nuclear Reactor



Source: United States Nuclear Regulatory Commission, *NRC: Boiling Water Reactors*, 2011
http://www.nrc.gov/reactors/bwrs.html

Beyond operational issues for the Isolated Island system, there are issues around the safe, long-term storage of nuclear waste associated with nuclear generation.

While nuclear generation has been deployed in many countries around the world, from a public policy perspective, the *Electrical Power Control Act, 1994* prohibits the construction and operation of nuclear power plants in the province.

Given that nuclear generation a) is prevented by provincial legislation and b) would not integrate well into the Isolated Island system, nuclear generation was screened out as a possible supply option alternative.

4.2.2 Natural Gas

Natural gas is used as a fuel source for combustion turbines and combined cycle combustion turbines throughout the industry. Technology exists to reconfigure a heavy oil fired facility such as Holyrood to burn natural gas.

The Provincial Energy Plan requires all offshore operators to propose a "landed" gas option as part of any development plan for natural gas. To date, no proposal for natural gas development, either export or "landing", has been submitted by the offshore operators despite years of technical and economic study. Nalcor has evaluated a range of natural gas configurations including modification of the Holyrood Plant to burn natural gas, and replacement of the Holyrood Plant with new high efficiency combined cycle gas turbines. Nalcor is of the view that "landed" Grand Banks natural gas is not a viable option to meet the island of Newfoundland's electricity needs. There are several reasons for this conclusion, as outlined below.

The first barrier to the development of natural gas is that the identified domestic market is too small to absorb the considerable project risks, capital investment, and operating costs of a Grand Banks natural gas development. A study prepared by Pan Maritime Kenny – IHS Energy Alliance in 2001[16] concluded:

> "Delivery of gas for domestic use for power generation, industrial, commercial, and residential is not economically feasible without integral development for delivery to Eastern Canada and the US."

The same report also concluded that the economic threshold for development of Grand Banks gas is a production rate in the order of 700 million standard cubic feet per day. Given the supply required for thermal generation is in the order of 100 million standard cubic feet per day at peak, the confirmed demand is far short of the economic threshold identified in the Pan Maritime Kenny – IHS Energy Alliance report.

This view is also supported by Navigant[17] in their review of natural gas as a potential supply option for thermal generation.

---

[16] Pan Maritime Kenny – IHS Energy Alliance, *Technical Feasibility of Offshore Natural Gas and Gas Liquid Development Based on Submarine Pipeline Transportation System*, 2001 (Exhibit 108**)**

[17] Navigant Consulting Ltd., *Independent Supply Decision Review*, 2011 (Exhibit 101)

The limited and varying use of discovered natural gas resources represents another impediment to Grand Banks natural gas development. Pan Maritime Kenny – IHS Energy Alliance concludes:

> "To date there is no single known field with gas resources large enough to support the cost of installation of a marine gas pipeline from the Grand Banks to markets in Eastern Canada and the U.S. So the natural gas development will need a basin-wide co-operative approach."

Natural gas is associated with the Hibernia, Terra Nova, and Whiterose developments, but each operator has its own strategies for the gas associated with their respective development. Natural gas associated with the Hibernia development is re-injected into the reservoir in order to increase the recovery of oil from the reservoir. This re-injection is a form of enhanced oil recovery, or EOR. In the case of the Terra Nova development, natural gas is re-injected and is also used to reduce the viscosity of produced crude oil, an EOR technique known as natural gas lift. Finally, natural gas from Whiterose is being stored in an adjacent reservoir for future use. Each operator has developed its own strategy for natural gas use, and to date, no concrete plan for domestic natural gas development exists.

Given the lack of a confirmed development plan for Grand Banks natural gas, the small domestic requirement in comparison to the economic threshold for development, as well as the varying uses by operators, Nalcor has screened out domestic natural gas as a supply option.

4.2.3 Liquefied Natural Gas (LNG)

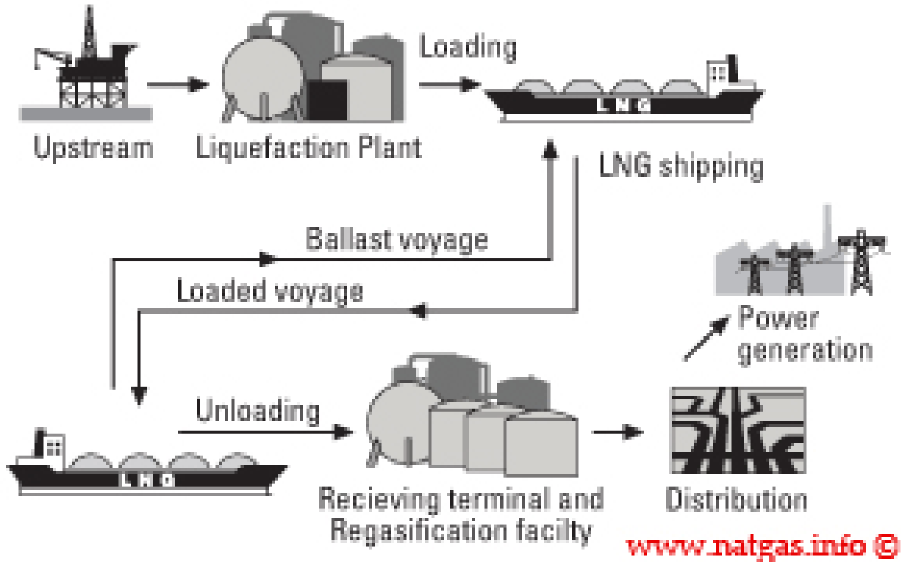
LNG is natural gas that has been cooled to about minus 163 degrees Celsius for shipment and/or storage as a liquid. The volume of the gas in its liquid state is about 600 times less than in its gaseous form. In this compact form, natural gas can be shipped in special tankers to receiving terminals. At these terminals, the LNG is returned to a gaseous form and transported by pipeline to distribution companies, industrial consumers, and power plants.

When in the reservoir, natural gas is found in three states: non-associated, where there is no oil contact; gas cap, where it is overlying an oil reserve; and associated gas, which is dissolved in the oil. The composition of the natural gas defines how it will be processed for transport. Whether staying in its gaseous state or being transformed into a liquid, natural gas from the well must undergo separation processes to remove water, acid gases and heavy hydrocarbons from the recovered natural gas.

The next step in processing is determined by what type of transport the gas will undergo, and specifications are met according to the transportation system. For LNG, additional processing is required before the condensation of the gas to remove the threat of crystallization in the heat exchangers in the liquefaction plant. When chemical conversion is used to liquefy natural gas, the conversion process determines which preliminary process must be used. Additionally, fractionation between methane and heavier hydrocarbons is performed during liquefaction. This way, after regasification the fuel can be loaded directing into the distribution network of pipelines.

LNG is then introduced into specially insulated tankers and transported to market. LNG is kept in its liquid form via auto refrigeration.

Figure 8: Liquified Natural Gas Chain



Source: natural gas. Info, *The Independent Natural Gas Information Site*, website, 2011
http://www.natgas.info/index.html

Once it has reached its destination, the LNG is offloaded from the tanker and either stored or regasified. The LNG is dehydrated into a gaseous state again through a process that involves passing the LNG through a series of vaporizers that reheat the fuel above the -160°C temperature mark. The fuel is then sent via established transportation methods, such as pipelines, to the end users.

An LNG receiving terminal would require a jetty, offloading equipment, LNG storage tanks, regasification plant, and a pipeline to power a generation station. The power generation plant would use a combined cycle combustion turbine.

A key challenge to any scenario for natural gas-fired power generation in Newfoundland is the small market. Natural gas markets are subdivided into industrial, municipal, and utility generation. Currently, Newfoundland and Labrador has no industrial base for use of natural gas. Neither is there a large readily available residential market for distributed natural gas. As a result, the primary and likely only use for natural gas is the electricity sector, but to utilize any amount of LNG, a costly regasification terminal has to be constructed and operated. One advantage of conventional fuels such as diesel fuel or the heavy fuel oil used at Holyrood is that the only infrastructure required is an appropriately sized tank farm. The natural gas volumes required to generate the island's electricity are very low compared to the scale of cost effective infrastructure being deployed worldwide. To meet the island's electricity needs, an import facility and regasification plant capacity in the range of 100 MMscf/d would be the required size. The facility would have to be built to meet winter peak electricity demands for a relatively few days and operate at much lower levels for the rest of the year.

LNG is a commodity that is actively traded on the global market by large scale, multi-national suppliers and transported globally on specially designed tankers. In order to consider LNG as a viable alternative source of electrical generation, as a utility Nalcor must be able to enter into a long term supply arrangements with global providers. As the only firm demand for LNG in the Isolated Island alternative would be electricity production, the volume of LNG that would be required would be viewed as small in the global market. Low quantities, combined with the need for long term supply contracts, would result in Nalcor paying a premium for LNG, likely comparable to prices that are found in the Asian market. Following the initial contract, Nalcor's ability to negotiate future prices at a lower or comparable rate may be frustrated because there is a high probability that suppliers will realize that LNG is Nalcor's only option. For decision making purposes, prudent pricing assumptions which reflect the realities of an existing and established market is essential. In the case of LNG, however, there is currently no certainty around current or future LNG pricing in a market comparable to the island of Newfoundland.

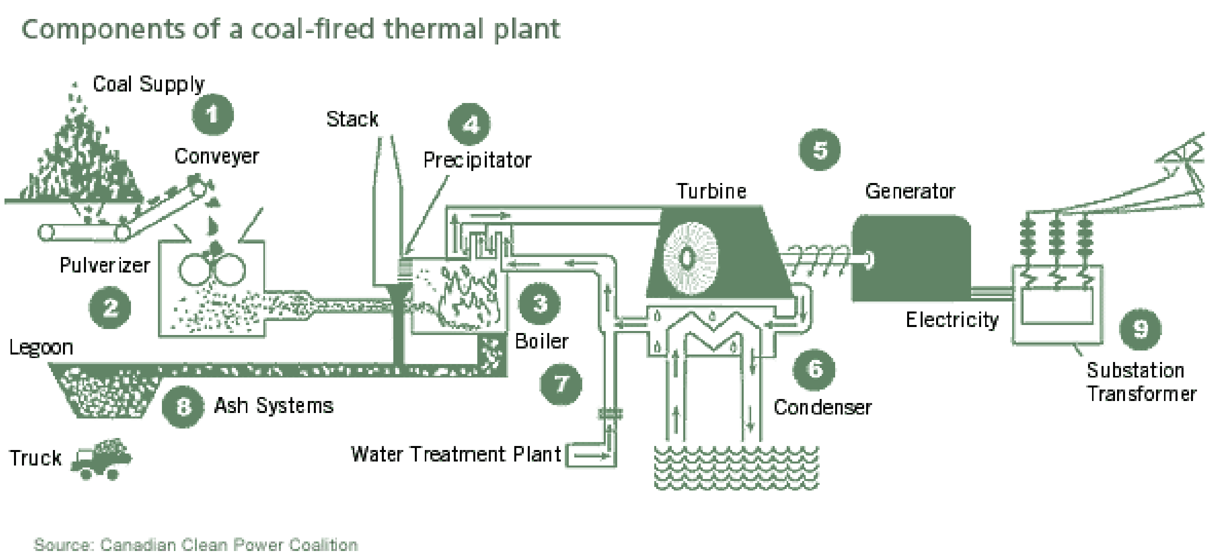
When analyzed from a cost perspective, LNG supplied at Asian prices virtually mirrors the forecasted cost of fuel for the Holyrood Thermal Generating Station. This means there is no clear advantage to LNG for rate payers. Nalcor's extensive analysis of supply alternatives show that the Interconnected Island Alternative, specifically Muskrat Falls and LIL, is considerably less expensive than the Isolated Island alternative, which is a predominantly thermal future.

4.2.4 Coal

Coal has a long history as a fuel source in North America. It has been used to heat homes, power machinery and transportation, and power electric generators. While most of coal's uses have been phased out, coal remains a significant fuel-source for electrical generation. According to the federal government there are 51 coal burning units in Canada[18], which account for approximately 19 percent of the electric generating capacity in the country[19]. The coal fired generating capacity produces 13 percent of Canada's total greenhouse gas (GHG) emissions[20]. Of the 51 coal fired generating units, 33 are expected to come to the end of their economic lives by 2025[21].

Coal-fired electric generation draws its fuel from vast reserves of non-renewable, naturally occurring deposits of coal. Coal reserves are mined, processed and transported to the generation site where they are pulverised and fed into a boiler to generate heat energy. The heat energy is used to produce steam. The steam is used to power a turbine which turns an electric generator. Figure8 below represents a typical coal-fired generator.

Figure 8: Components of a Typical Coal-Fired Generator



Source: Centre for Clean Energy, *How does a thermal power plant work?*, 2011
http://www.centreforenergy.com/AboutEnergy/Thermal/Overview.asp?page=4

[18] Government of Canada, *Government of Canada to Regulate Emissions from Electricity Sector*, 2010 http://www.ec.gc.ca/default.asp?lang=En&n=714D9AAE-1&news=E5B59675-BE60-4759-8FC3-D3513EAA841C

[19] Government of Canada, *Backgrounder: Canada's Electricity Story*, 2010 http://www.ec.gc.ca/default.asp?lang=En&n=714D9AAE-1&news=0A6CF209-AF7A-4913-A27F-527B4ECF811B

[20] Government of Canada, *Government of Canada to Regulate Emissions from Electricity Sector*, 2011 http://www.ec.gc.ca/default.asp?lang=En&n=714D9AAE-1&news=E5B59675-BE60-4759-8FC3-D3513EAA841C

[21] Government of Canada, *Government of Canada to Regulate Emissions from Electricity Sector*, 2010 http://www.ec.gc.ca/default.asp?lang=En&n=714D9AAE-1&news=E5B59675-BE60-4759-8FC3-D3513EAA841C

Historically the benefits of coal-fired generation have been based on economics. With an abundant supply of coal resources, the relative ease to transport the resource by rail and/or sea, and the relatively high energy content meant that significant energy potential could be harnessed at relatively low unit costs.

Technologies such as electrostatic precipitators (ESPs) and scrubbers greatly reduce the amount of non-GHG emissions from coal-fired units. However, pollution abatement technologies come at significantly increased capital and operating costs for new coal-fired facilities. These cost increases reduce the economic case for coal-fired generation in the long run. Pollution abatement equipment costs, coupled with the generally expected increased costs related to the stringent regulation of emissions, render the future of coal-based alternatives questionable.

The future of continued favourable economics for coal-fired generation is under considerable doubt based on the quantity of GHG emissions from these sources. The trend in multiple jurisdictions is clearly away from coal. Both the Canadian and American governments are committed to the limiting the amount of emissions derived from the electricity industry[22,23]. The pending, and now gazetted, Canadian regulations require new generation facilities to have maximum CO_2 emissions comparable with those of highly efficient natural gas fired combined cycle combustion turbines (375 tonnes per GWh).

Because of uncertainty in costs and feasibility associated with meeting gazetted federal regulations, there is significant risk in pursuing coal-fired generation as a resource option. Carbon capture and storage technology (CCS) would be required for a coal-fired facility to achieve the proposed federal target. This unproven technology is still at the research and development phase and has not been deployed on a commercial scale. Saskatchewan has

---

[22] Government of Canada, *Government of Canada to Regulate Emissions from Electricity Sector*, 2010 http://www.ec.gc.ca/default.asp?lang=En&n=714D9AAE-1&news=E5B59675-BE60-4759-8FC3-D3513EAA841C

[23] Government of the United States, Environmental Protection Agency, *Cross State Air Pollution Rule (CSAPR)*, webpage, 2011
http://www.epa.gov/airtransport/

recently approved a $1.2 billion project to implement CCS demonstration project on the 110 MW Unit 3 of SaskPower's Boundary Dam thermal facility[24].

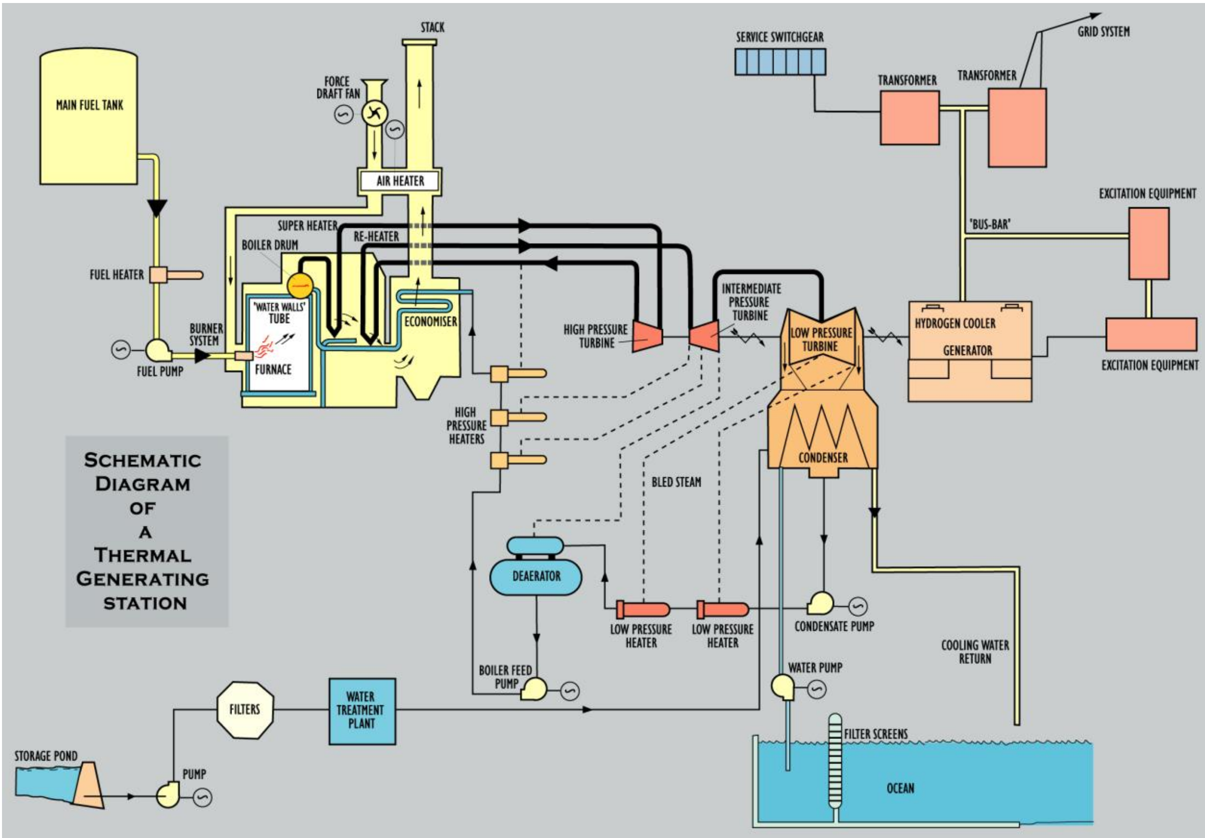
Given the potential for GHG regulation and the uncertainy and cost associated with CCS coal-fired generation was screened out as an alternative source for the Isolated Island alternative.

4.2.5 Continued Oil-Fired Generation at the Holyrood Plant

The Holyrood Thermal Generating Station is a three unit heavy oil fired, steam cycle generating plant located in the municipality of Holyrood. The plant was constructed in two stages. In 1969, Stage I, consisting of two generating units (Units 1 and 2) each capable of producing 150 MW, was started and placed in service in April 1971. In December 1979, Stage II, consisting of one generating unit (Unit 3) capable of producing 150 MW, was completed. The Unit 3 generator is capable of synchronous condenser operation to assist in grid voltage control during the off peak season. In 1988 and 1989, Units I and 2 were modified to increase their output to 175 MW respectively. Today the Holyrood Plant has a net rated capacity of 465.5 MW after allowance for station service loads and a firm energy capability of 2,996 GWh per year. At peak production, the plant burns approximately 18,000 barrels of oil per day. Figure 9 below depicts the Holyrood Plant.

[24] Government of Saskatchewan, *Government Approves $1.24 Billion Carbon Capture Project*, Press Release, 2011 http://www.gov.sk.ca/news?newsId=ae413247-80ce-4c9a-b7e3-4cc39e89da94

Figure 9: Thermal Generating Station Schematic



Source: NLH

The life expectancy of a base-loaded thermal generating station is generally accepted to be 30 years where the plant operates continuously and downtime is scheduled only to perform routine repairs and maintenance. However, the 30-year life expectancy can vary depending on the operating hours, the cycling between low/no load and peak load, and how well it has been maintained over its life. When a thermal plant has reached or exceeded its life expectancy, life extension work is required to continue safe, reliable and least cost operation.

Stage I of the Holyrood plant is over 40 years old and Stage II has surpassed the 30-year mark. At this point in the life of the Holyrood Plant, condition assessment is required to determine the life extension program necessary for the plant to continue to operate for the next 30 years (i.e., to the end of 2041). To this end NLH applied to the Board to begin Phase 1 of a condition assessment and life extension program for the plant. The Board granted partial approval to proceed and the engineering consulting firm AMEC completed the Phase 1 work in March of 2011. The project was limited in scope and considered required Holyrood plant operation to the end of 2016 and maintenance in a standby power mode from 2017 to 2020. Beyond 2020 the project scope limited plant operation to synchronous condenser mode only. Phase 2 of the existing condition assessment and life extension program will enable NLH to identify equipment and systems that require immediate attention to operate Holyrood to the year 2016. In the context of long-term, continued oil fired operating at the Holyrood plant, additional condition assessment and life extension analysis must be performed. NLH engineering and operating experience and expertise, along with Information from the AMEC Phase 1 report, were used to formulate an upgrade program for the Holyrood facility through to the 2041 timeframe. While these cost provisions are based on operating and capital experience it does offer an initial provision of costs where need is known but the full scope for life extension capital is unknown in the expansion plans. The total capital cost for Holyrood Plant Life extension is estimated at $233 million (in service cost). Additional details are provided in Section 5.4.

Beyond the life extension issues associated with the wear and tear on the physical equipment, the Holyrood Plant is a large source of atmospheric pollution in the province. Particulate, sulphur dioxide (SO_2) and GHGs including CO_2 are of primary concern. At present the Holyrood plant does not have any environmental equipment for controlling particulate emissions or SO_2. To date NLH has managed SO_2 emissions through the burning of lower sulphur content heavy oil. To meet the provincial commitments of the province's Energy Plan, NLH has identified ESPs and wet limestone flue gas desulphurization (FGD) systems to control particulate and SO_2 emissions from the plant in the absence of the Lower Churchill Project. The costs associated with these precipitators, scrubbers and low NOx burners are estimated at $602 million (in service cost). Additional details are provided in Section 5.4. The cost for pollution abatement has been included in the Isolated Island alternative.

With respect to GHG emissions, Federal regulatory action against emitting facilities is increasingly likely. Depending upon the federal benchmark for GHG emission intensity levels, there is risk that an oil fired facility such as the Holyrood plant may not be able to legally operate in the long-term.

Continued oil-fired generation at the Holyrood plant is viewed as a viable alternative in both the short- to medium-term. Consequently, the continued operation of Holyrood with the appropriate pollution abatement technology was included in the generation expansion alternatives.

4.2.6 Simple Cycle Combustion Turbines

A simple cycle combustion turbine power plant (CT) consists of an air compressor, combustion chamber, turbine and generator. CTs can be operated using either natural gas or light fuel oil (LFO). CT operation begins with air being drawn into the front of the unit, compressed in a compressor, and mixed with natural gas or LFO in the combustion chamber. Next the mixture of compressed air and natural gas or LFO is ignited producing hot gases that rapidly expand. The expanding hot gas is passed through a turbine which turns an electric generator to produce electricity. Figure 10 provides a diagram of a typical combustion turbine.

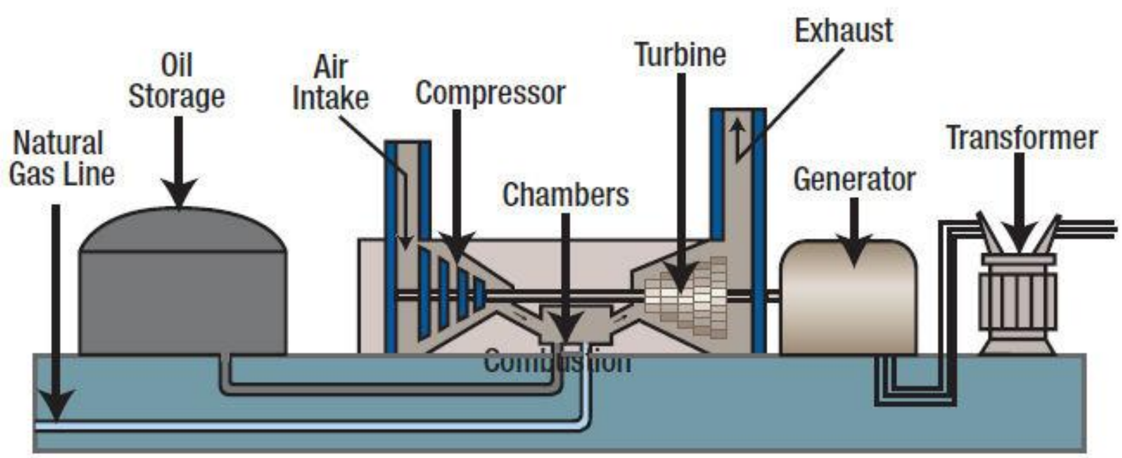


Figure 10: Components of a Typical Simple-Cycle Combustion Turbine

Source: Tennessee Valley Authority, *Integrated Resource Plan,* 2011
http://www.tva.gov/environment/reports/irp/pdf/simple_cycle_turbine.pdf

Simple cycle combustion turbines are capable of producing large amounts of useful power for a relatively small size and weight. Since motion of all its major components involve pure rotation (i.e. no reciprocating motion as in a piston engine), its mechanical life is long and the corresponding maintenance cost is relatively low. A simple cycle combustion turbine must be started using some external means such as an electric motor, air compressor or another combustion turbine. A CT can be started, connected to the power system and loaded to its rated output in minutes.

Combustion turbine installations on the island system would have a nominal rating of 50 MW (net) per unit and would be located either adjacent to existing NLH thermal operations or at greenfield sites near existing transmission system infrastructure. While CTs have a relatively low capital cost, fuel costs are high. As a result, CTs on the island system are generally used for only short periods of time. Due to their low simple cycle efficiency, CTs are primarily deployed on the island system for system reliability and capacity support for peak demand. If required, CTs can be utilized to provide firm energy to the system.

Combustion turbine technology is an integral part of the resource mix on the Isolated Island system today. CTs are applicable and necessary supply resource for both the Isolated Island alternative and the Interconnected Island alternative. Consequently, the combustion turbine technology was included in the generation expansion alternatives.

4.2.7 Combined Cycle Combustion Turbine

A combined-cycle combustion turbine consists of a simple cycle combustion turbine as described in Section 4.2.6, a heat recovery steam generator (HRSG), and a steam turbine generator. CCCT technology is widely used in North America as a flexible and efficient generating alternative.

The exhaust of the CT is passed through a HRSG to produce steam. Steam from the HRSG powers the steam turbine generator. The condensed steam is then recycled back into the HRSG. The CT provides about two-thirds of the generated power and the steam turbine about one-third. The heat recovery from the CT provides a large efficiency improvement over a stand-alone CT.[25]

Figure 11 depicts one form of a combined cycle combustion turbine.

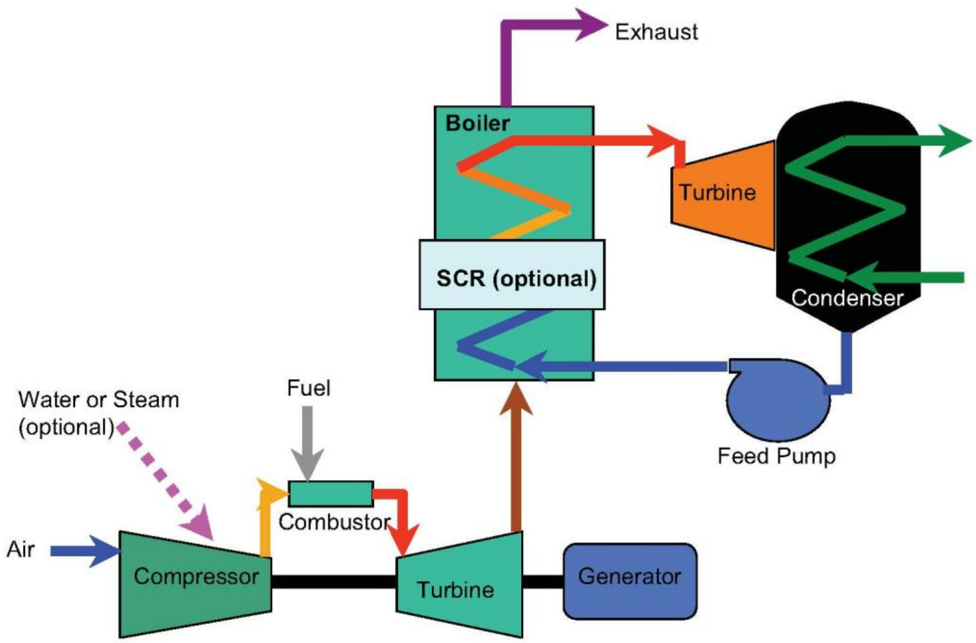
One of the primary benefits of a CCCT plant is that it can be used as base load power generation. A CCCT generator is more efficient than either a stand-alone combustion turbine or steam turbine. A CCCT plant is essentially an electrical power plant in which combustion turbine and steam turbine technologies are used in combination to achieve greater efficiency than would be possible independently. This high fuel efficiency makes it possible for CCCTs to be competitive for intermediate or base load applications at relatively high price fuels.

CCCT plants are subject to the cost variations associated with various fuel markets. This can have an adverse effect on electricity production costs, and in turn, could cause uncertainty around long-term electricity rates if the price of fuel rises over time.

---

25 Tennessee Valley Authority, *Integrated Resource Plan,* 2011 http://www.tva.gov/environment/reports/irp/pdf/simple_cycle_turbine.pdf

Figure 11: Typical Components of a Combined Cycle Combustion Turbine



Source: Tennessee Valley Authority, *Integrated Resource Plan*, 2011
http://www.tva.gov/environment/reports/irp/pdf/combined_cycle_turbine.pdf

To incorporate CCCT technology into the island's resource mix, NLH would use LFO rather than natural gas, as natural gas infrastructure is not available locally at this time. As a result, a new CCCT generating facility using LFO would need to be located close to a suitable seaport in order to reduce bulk fuel shipping costs and to provide plant cooling water.

The applicable power rating for a CCCT connected to the island system is a 170 MW unit size based on the size of the largest unit on the island system today and the system's ability to withstand the loss of a large generator. This technology could be used as a replacement for the Holyrood plant or as additional generation to meet load growth. The annual firm energy capability is 1,340 GWh for the 170 MW option[26].

CCCTs are an applicable supply resource for both the Isolated Island alternative and the Interconnected Island alternative. Consequently, the combined cycle combustion turbine technology was included in the generation expansion alternatives.

[26] NLH, *Generation Planning Issues July 2010 Update*, 2010 (Exhibit 16)

4.2.8 Wind

Wind energy (or wind power) refers to the process by which wind turbines convert the movement of wind into electricity. Winds are caused by the uneven heating of the atmosphere by the sun, the irregularities of the earth's surface, and rotation of the earth. Wind energy is harnessed through the use of wind turbines. Wind turbines have three aerodynamically designed blades which spin on a shaft which connects to a generator that produces electricity. Wind passes over the blades, creating lift (just like an aircraft wing) which causes the rotor to turn[27]. Stronger winds will produce more energy. Wind turbines can operate across a wide range of wind speeds - generally from 10 up to 90 km/h[28]. Wind turbines are mounted on a tower to capture the most energy. At 30 metres or more above ground, they can take advantage of faster and less turbulent wind.

Figure 12 below shows a typical wind turbine.

The majority of current turbine models make best use of the constant variations in the wind by changing the angle of the blades through "pitch control", by turning or "yawing" the entire rotor as wind direction shifts and by operating at variable speed. Operation at variable speed enables the turbine to adapt to varying wind speeds. Sophisticated control systems enable fine tuning of the turbine's performance and electricity output. Modern wind technology is able to operate effectively at a wide range of sites – with low and high wind speeds, in the desert and in freezing arctic climates[29].

In a wind farm, individual turbines are interconnected with a power collection system and a communications network. The power is then transferred to the electricity grid.

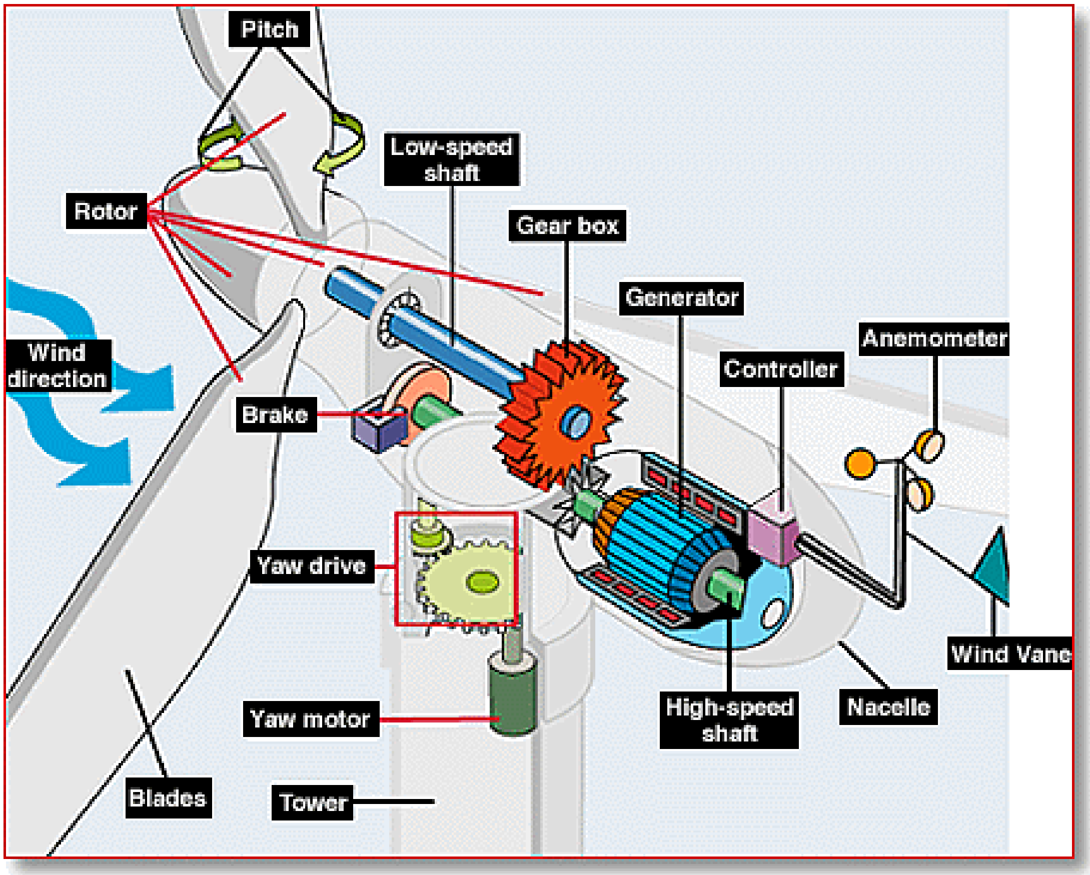
---

27 The European Wind Energy Association, *How a Wind Turbine Works*, webpage, 2011 http://www.ewea.org/index.php?id=1922

28 Global Wind Energy Council, *Wind energy technology,* webpage, 2011 http://www.gwec.net/index.php?id=31

29 Global Wind Energy Council, *Wind energy technology,* webpage, 2011 http://www.gwec.net/index.php?id=31

Figure 12: Components of a Typical Wind Turbine



Source: Government of the United States, Department of Energy, *How Wind Turbines Work*, webpage, 2011 http://www1.eere.energy.gov/wind/wind_how.html#inside

There are obvious benefits to wind energy. Wind energy is fueled by the wind, so it's a clean fuel source. Wind energy does not generate air pollution or produce atmospheric emissions that cause acid rain or GHGs.

Electricity generated from wind power can be highly variable at several different timescales: from hour to hour, daily, and seasonally: annual variation also exists. Related to variability is the short-term (hourly or daily) predictability of wind plant output. Wind power forecasting methods are used, but predictability of wind plant output remains low for short-term operation. Because instantaneous electrical generation and consumption must remain in balance to maintain grid stability and ensure the electricity is available when the customer needs it, this variability can present substantial challenges to incorporating large amounts of wind power into the Isolated System.

Good wind sites are often located in remote locations, far from places where the electricity is needed. Transmission lines must be built to bring the electricity from the wind farm to the places of high demand.

Newfoundland and Labrador has an excellent wind resource. However, for the Isolated Island setting, the amount of wind power that can be integrated into the island grid is limited. The 2004 NLH study *An Assessment of Limitations For Non-Dispatchable Generation On the Newfoundland Island System*[30] established two limits regarding the possible level of wind generation integration on the Isolated Island system, an economic limit and a maximum technical limit. The study determined that for wind generation in excess of 80 MW there would be a significant increase in the risk of spill at the hydroelectric reservoirs. This would occur when Hydro's reservoir levels were high and system loads were such that the system operator had to decide between curtailing wind generation and allowing water to spill over the dam. Either way, the economic advantage of the wind would be diminished. The study further determined that for wind generation above 130 MW it would not always be possible to maintain system stability particularly during periods of light load and during these periods wind generation would have to be curtailed, again, reducing the economic benefit of the additional wind generation.

The limits identified in the 2004 study are still applicable today. However, as load grows, the Isolated Island system should be able to accommodate additional wind generation. It has been suggested that the system should be able to accommodate an additional 100 MW of wind in the 2025 timeframe and a further 100 MW around 2035[31]. NLH will study this prior to Decision Gate 3 (DG3). As well, as a result of system constraints, and recognizing the inherently intermittent nature of the wind resource, the use of a large-scale wind farm to replace the firm continuous supply capability of the Holyrood generating plant is not operationally feasible and therefore was not considered in the generation expansion analysis.

[30] NLH, *An Assessment of Limitations for Non-Dispatchable Generation on the Newfoundland Island System*, 2004 (Exhibit 61)

[31] Navigant Consulting Ltd*., Independent Supply Decision Review*, 2011 (Exhibit 101)

NLH has not completed an analysis to establish the level of wind generation that could be sustained in the Muskrat Falls LIL high voltage direct current (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 be reasonable to consider the addition of up to 400 MW of wind generation on the system.

Onshore wind power typically costs 8–12 ¢/kWh, depending largely on how windy the site is and how far it is from existing power transmission lines[32]. Good wind sites on the island are at the lower end of this cost range. The estimated average cost incorporates the cost of construction of the turbine and transmission facilities, borrowed funds, return to investors (including cost of risk), estimated annual production, and other components, averaged over the projected service life of the equipment, which is typically around twenty years. Costs associated with any bulk system transmission upgrades that may be required because of the size and/ or location of the wind farm are not included in the estimated generation costs.

Wind power has a place in the electricity generation mix on the island and due to its low environmental footprint, it will be incorporated whenever economically viable. However, technical and operational considerations limit the amount of wind generation that can be operated on the system.

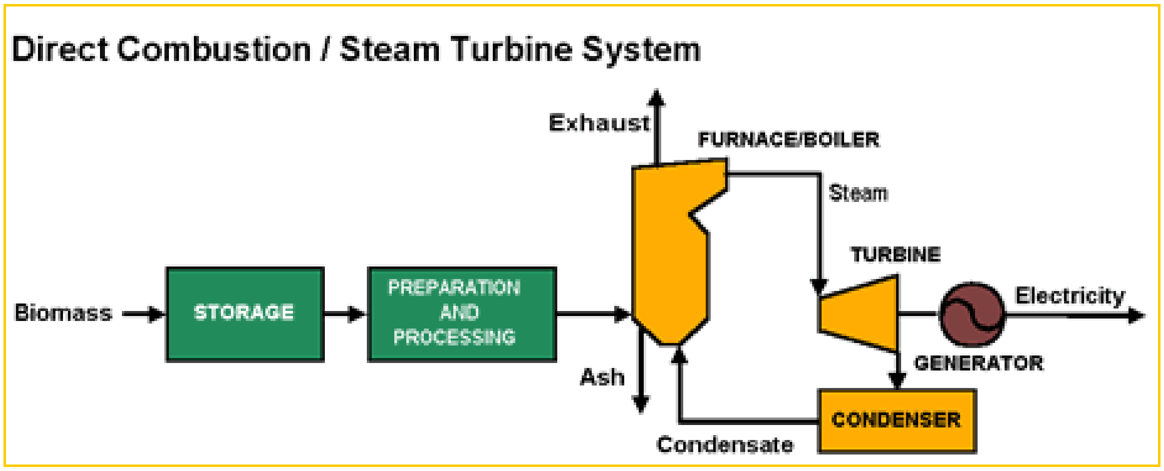
4.2.9 Biomass

Biomass energy is derived from many different types of recently living organic matter (feedstock). However, in the context of producing large-scale energy, it is likely that the focus would be on harvesting forestry products as fuel for the biomass generator. Biomass works similar to many other thermally-based generators in that wood or other biomass products are harvested, treated and then transported to the generation plant to be used in place of other solid fuels such as coal to generate heat. The heat is then used to produce steam. The steam is in turn fed into a turbine that turns a generator to produce electricity.

[32] The Pembina Institute, *Wind Power Realities*
http://www.pembina.org/docs/re/web-eng-wind-factsheet.pdf

Figure 13 below shows how one type of biomass technology could be deployed.

Figure 13: Typical Biomass Technology



Source: Government of the United States, Department of Energy, *Guide to Tribal* Energy *Development: Biomass Energy – Biopower*, 2011 http://www1.eere.energy.gov/tribalenergy/guide/biomass_biopower.html

One of the best advantages of biomass is the low GHG production net of the harvesting and transportation operations. Furthermore, biomass is a renewable energy source if forests are properly managed. Biomass could also provide increased markets for the province's forestry industry as any new plants would require significant feedstock.

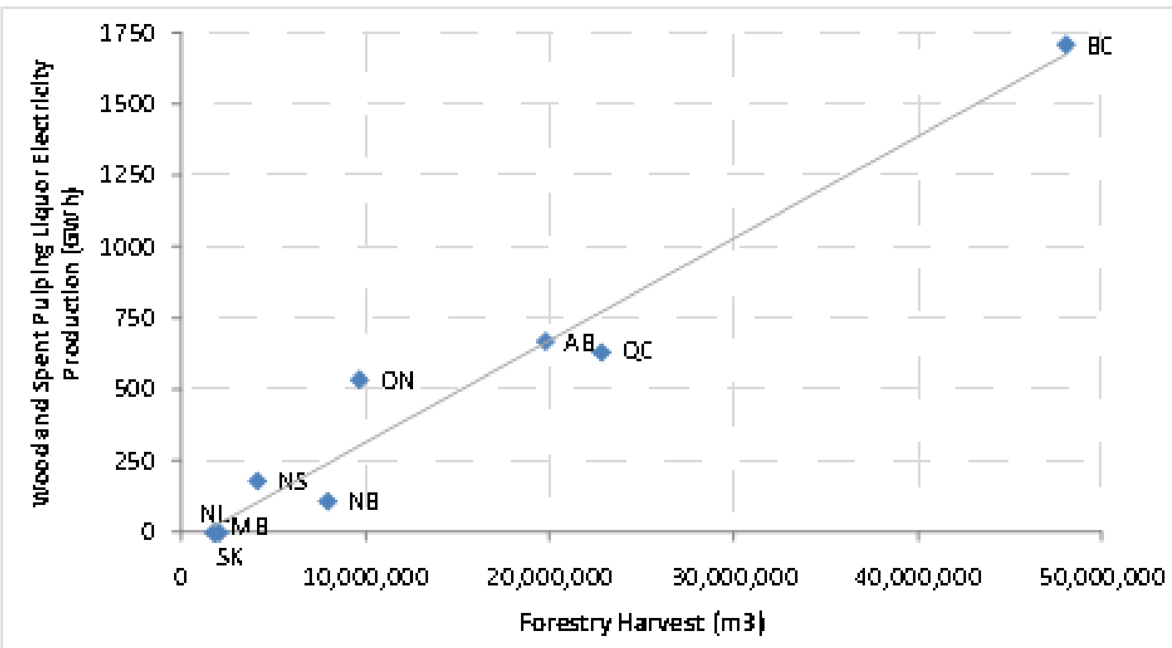
Biomass plants, which typically operate more efficiently at base load values can load-follow within certain ramp rates. Assuming economics, therefore, and that readily available feedstock was not a concern, a biomass plant could reasonably be integrated into the Isolated System.

Biomass generation requires significant and steady supplies of feed-stock to support generation operations. The security of supply is critical in order to maintain stable generation. The National Forestry Registry has placed the province's annual forestry harvest seventh of Canadian provinces at some 2-million cubic metres[33]. Therefore, significant development of this industry would be required in order to facilitate the addition of a biomass generator.

[33] Government of Canada, *National Forestry Database: Forestry Highlights, 2009*, webpage, 2011 http://nfdp.ccfm.org/highlights_e.php

Generally speaking, electricity production from biomass leverages the infrastructure used to harvest forestry products for other purposes (such as lumber and pulp and paper production). The strong relationship between forestry harvest and biomass electricity production is clearly shown below in Figure 14 in which electricity produced from wood and spent pulping liquor (vertical axis) is plotted against annual forestry harvest (horizontal axis) for nine provinces.

Figure 14: Electricity Production from Wood and Spent Pulping Liquor vs. Forestry Harvest by Province



Source: (1) Government of Canada, *National Forestry Database*, webpage, 2011 http://nfdp.ccfm.org/index_e.php
(2) Statistics Canada, *Report on Energy Supply and Demand in Canada*, 2009

As shown, British Columbia has both the highest forestry harvest and the highest volume of electricity produced from wood and spent pulping liquor. Not all of the provinces fall on the line shown in the figure, but there is clearly a relationship between electricity produced from wood and spent pulping liquor and forestry harvest.

Based on this relationship and Newfoundland and Labrador's annual forestry harvest, it is estimated that the Province may have capacity for electricity produced from wood and spent pulping liquor in the range of perhaps 100 GWh by leveraging the existing infrastructure. This estimate is not the upper limit of electricity production; the Province certainly has significant areas of forest, but the infrastructure (access roads, vehicles and skilled labour) to harvest sufficient biomass to produce more than the estimated 100 GWh does not likely exist. As a result, higher levels of production are likely to require higher levels of infrastructure investment that ultimately result in higher biomass (and electricity costs).

Due to the requirement to harvest a large and steady supply of forestry products, manage and maintain the sustainability of the forest harvest, and transportation costs in getting the harvested material to the generation site, the unit costs for energy from biomass plants is usually much higher than other forms of energy.

Navigant Consulting Ltd. has worked with several recent biomass projects and has determined that the capital cost of a new biomass facility is about $3,500 per kW and the variable fuel cost would be on the order of $50-$100 per MWh giving a unit cost of about $150-$200 per MWh in the Province[34].

While biomass and other co-generation alternatives, when economically feasible, will be considered as future supply alternatives, they are not considered to be appropriate replacements for large-scale generation requirements due to the significant costs and risks around securing significant supply of feedstock. On this basis, biomass was screened out as an Isolated Island supply alternative.

[34] Navigant Consulting Ltd., *Independent* Supply *Decision Review*, 2011. (Exhibit 101)

4.2.10 Solar

Solar power is the conversion of sunlight into electricity. This is carried out by two main methods:

1. Using sunlight indirectly, Concentrating Solar Power systems use lenses or mirrors and tracking systems to focus a large area of sunlight into a small beam to boil water which is then used to provide power.

2. Using sunlight directly, a solar cell, or photovoltaic cell (PV), is a device that converts light into electric current using the photoelectric effect. Currently in Canada, solar power is focused primarily on photovoltaics.

Photovoltaic (PV)[35] literally means "*light*" and "*electric*." Photovoltaic technologies are used to generate solar electricity by using solar cells packaged in photovoltaic modules.

The most important components of a PV cell are the two layers of semiconductor material. When sunlight strikes the PV cell, the solar energy excites electrons that generate an electric voltage and current. Extremely thin wires running along the top layer of the PV cell carry these electrons to an electrical circuit.

A photovoltaic module is made of an assembly of photovoltaic cells wired in series to produce a desired voltage and current. The PV Cells are encapsulated within glass and/or plastic to provide protection from the weather. Photovoltaic modules are connected together to form an array. The array is connected to an inverter which converts the direct current (dc) of the PV modules to alternating current (ac). A typical solar cell array is illustrated in Figure 15.

[35] SunEdison, *How Solar Energy Works*, webpage, 2011 http://www.sunedison.com/how--solar-electricity-works.php

Figure 15: Solar Cell Array

Source: Stock Photo

There are a number of issues with using solar power as a generation source on the island system:

(1) Solar power is non-dispatchable; when the sun shines, the system has to take the power generated and when the sun is not shining, during the night, or during cloudy periods, other forms of generation have to be available for backup. The issues with non-dispatchability have been/will be discussed in the sections on "Wind" and "Other Small Hydro".

(2) NLH's peak demand period typically occurs in the winter during the supper hour. At that time, output from solar power will be nil. Thus, solar power will not provide any capacity at time of peak.

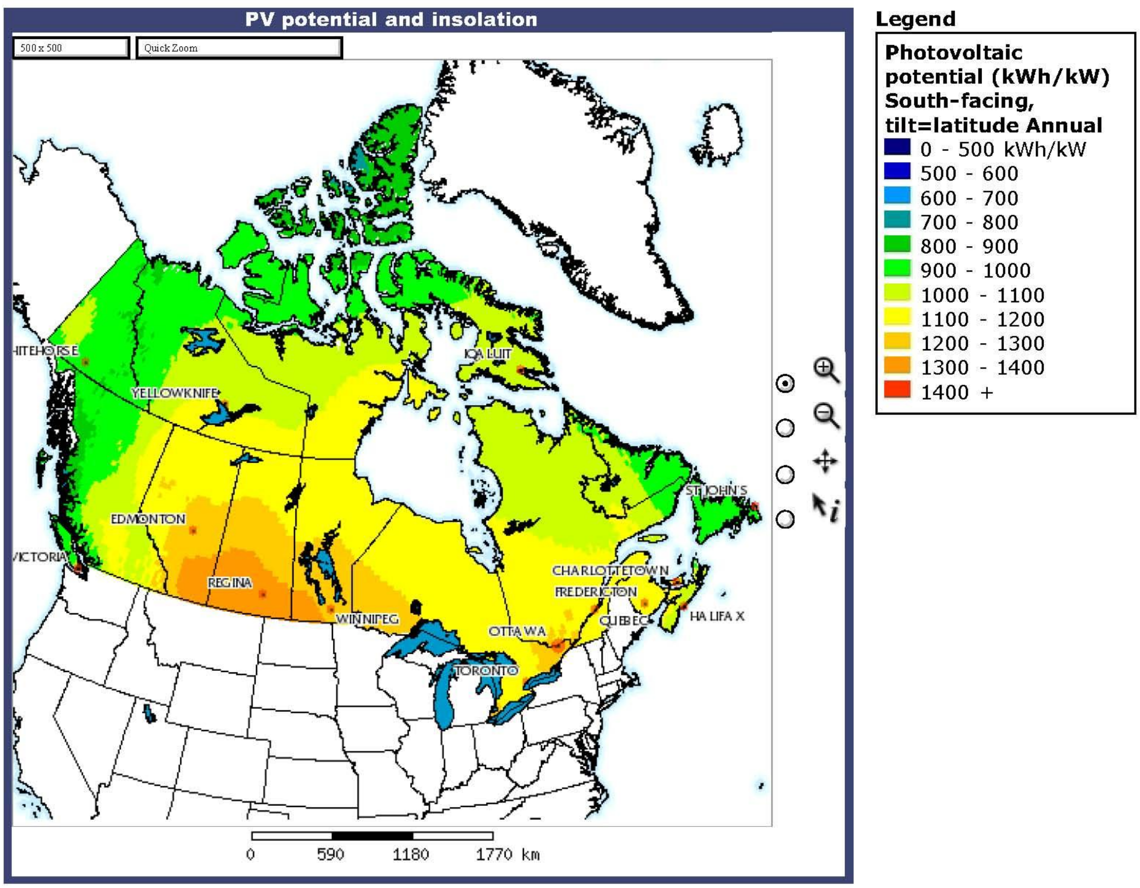
(3) Newfoundland and Labrador has one of the lowest rates of solar insolation in Canada, which would result in a low capacity factor and higher unit costs. Even in

areas where solar insolation is highest, unit costs for commercial solar energy production are amongst the highest of all generation sources.

According to Natural Resources Canada's website, their PV Potential and Insolation maps indicate that Newfoundland has the second lowest photovoltaic potential (kWh/kW) in Canada, as compared to all other provinces.

Figure 16 shows Newfoundland and Labrador's photovoltaic potential in relation to the rest of Canada.

Figure 16: Photovoltaic Potential in Canada



Source: Government of Canada, *PV potential and insolation,* webpage, 2011
https://glfc.cfsnet.nfis.org/mapserver/pv/pvmapper.phtml?LAYERS=2700,2701,2057,4240&SETS=1707,1708,1709,1710,1122&ViewRegion=-2508487%2C5404897%2C3080843%2C10464288&title_e=PV+potential+and+insolation&title_f=Potentiel+photovoltaïque+et+ensoleillement&NEK=e

With technology to harness solar energy still under development, panels and other units that collect and store the energy still remain prohibitively expensive on a cost per MW basis.

The combination of high cost, lack of availability of power at peak times in winter, lack of dispatchability and the province's low insolation rates resulted in solar being screened out as an Isolated Island supply alternative.

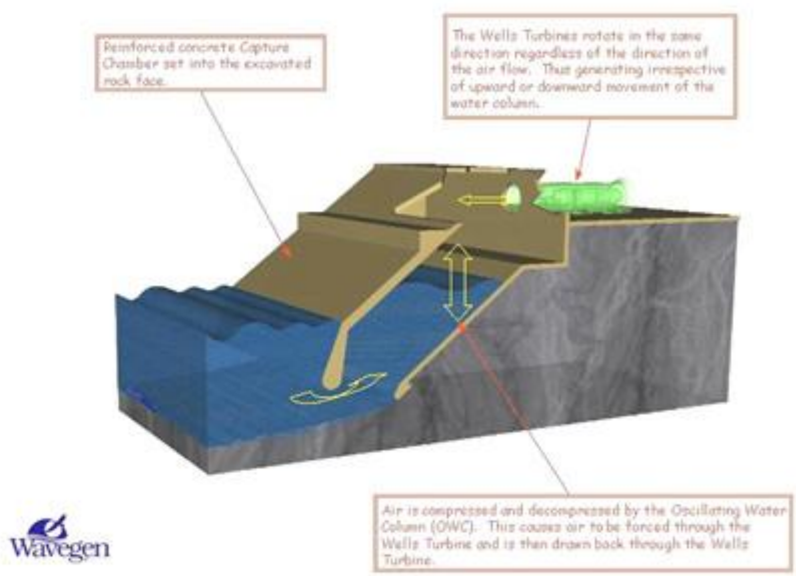
4.2.11 Wave and Tidal

Harnessing energy from the natural motion of the ocean currents and waves has long been considered and studied as a viable option for renewable energy production. Many different technologies have been proposed to approach the problem of extracting the wave and tidal energy to produce electricity.

Wave energy technologies work by using the movement of ocean surface waves to generate electricity. Kinetic energy exists in the moving waves of the ocean. That energy can be used to power a turbine. One type of wave generator uses the up and down motion of the wave to power a piston, which moves up and down inside a cylinder. The movement of the piston is used to turn an electrical generator.

A diagram of one type of wave generator is shown below in Figure 17.

Figure 17: Example of a Wave Generator

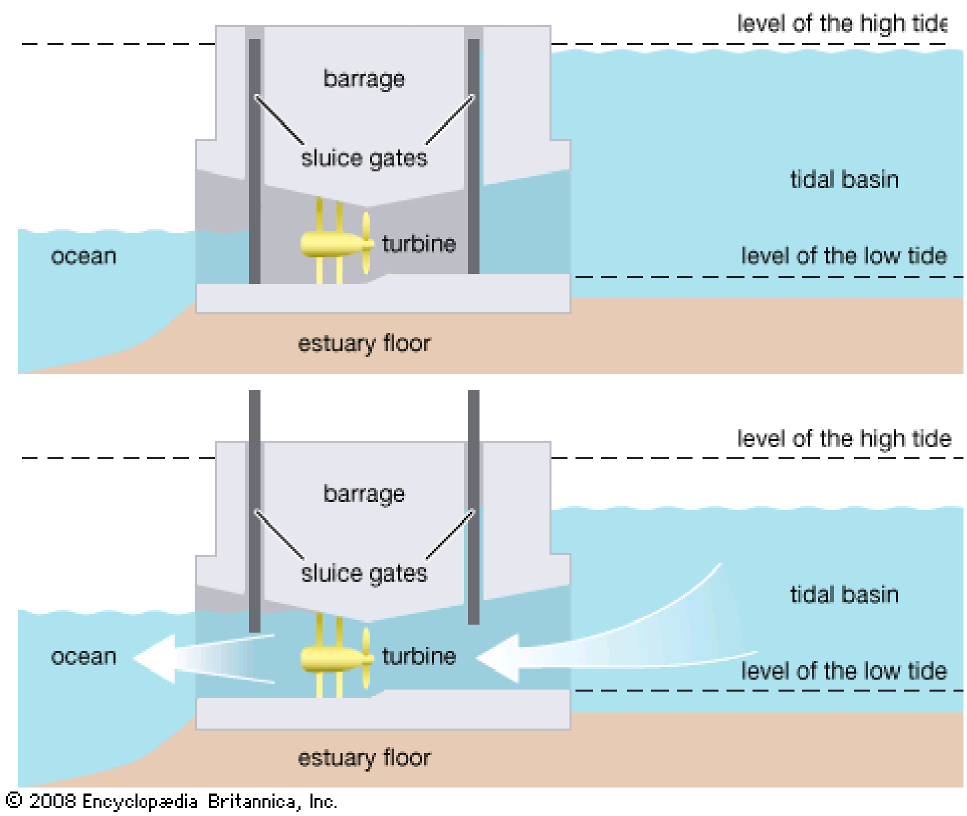


Source: University of Bath, *Alternative Sources for Electricity Generation - Wave Power*, webpage, 2011 http://people.bath.ac.uk/dpk20/Website_files/page0006.htm

Tidal power is based on extracting energy from tidal movements and the water currents that accompany the rise and fall of the tide. When the tide rises, the water can be trapped in a reservoir behind a dam. Then when the tide falls, the water behind the dam can be released through a turbine similar to a regular hydroelectric power plant.

Figure 18 below depicts one type of tidal generator. The system uses sluice gates and a barrage to trap the ocean water when it reaches its high tide level. The water is released when the tide falls, and the movement of the water is used to turn a turbine and generator to produce electricity.

Figure 18: Example of a Tidal Generator



Source: Encyclopedia Britannica, t*idal power barrage*, webpage, 2011
http://www.britannica.com/EBchecked/media/125135/Diagram-of-a-tidal-power-barrage

Wave and tidal energy provide a number of benefits. First, both are a clean energy source and do not emit any GHGS while generating electricity. Ocean tides are predictable and occur on a regular basis. Also, wave energy is less intermittent than wind or solar power[36].

However, wave and tidal energy installations face some limitations. The primary limitation is the fact that the ocean environment can be harsh on the equipment used in wave and tidal installations. As a result, the equipment used must be built robustly in order to contend with waves and salt water. Consequently, wave and tidal generators can cost approximately three to four times more than wind turbines per megawatt[37]. Another limitation is the fact that in order for a tidal generator to work well, a large variation in tidal levels is required. This limits the locations where tidal generation can be installed to produce large amounts of electricity in an efficient manner[38].

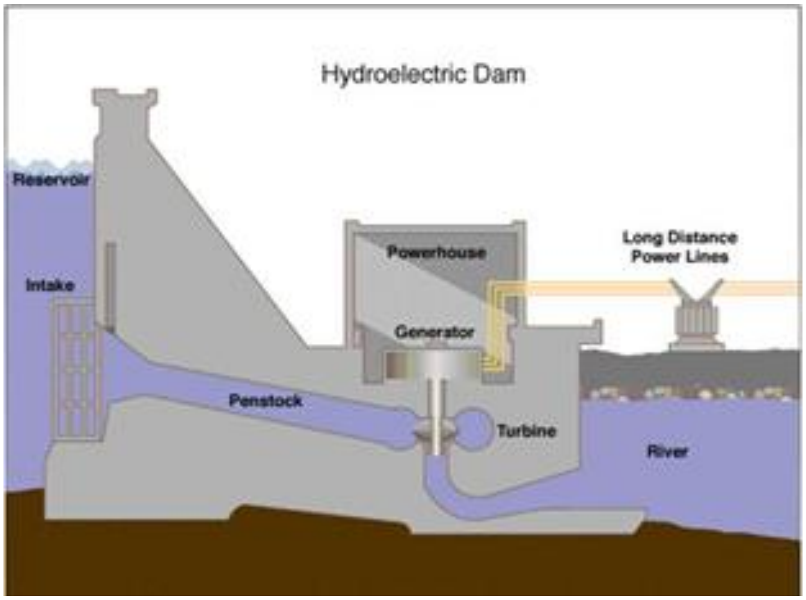
Despite some limited successes, neither tidal nor wave power has become a commercial mainstream source of renewable energy. Consequently, NLH screened out the use of wave and tidal power as an alternative supply option for the Isolated Island alternative.

4.2.12 Island Hydroelectric

Hydroelectric stations generate electricity using the kinetic energy of falling water. Some plants are constructed at natural drops in rivers, while others employ dams to raise the upstream water above downstream levels.

[36] Electric Light & Power, *Wave and Tidal Power Growing Slowly, Steadily*, December 2009
[37] Ibid.
[38] Ocean Energy Council, *Tidal Energy* http://www.oceanenergycouncil.com/index.php/Tidal-Energy/Tidal-Energy.html

Figure 19: Diagram of Hydroelectric Dam



Source: Government of Canada, *Atlas of Canada: Diagram of a Hydroelectric Dam*, webpage, 2011
http://atlas.nrcan.gc.ca/site/english/maps/economic/energy/Dams/hydro.jpg/image_view

Typically, a hydroelectric station generates electricity as follows:

Water from a reservoir or river flows through the intake, an underwater opening into a pipe or tube called the penstock. Water flows down through the penstock under increasing pressure. At the end of the penstock, a turbine is mounted, inside a powerhouse. As the water pushes its blades, the turbine rotates. This turns an internal shaft connected to a generator, and electricity is produced. As the water exits the turbine, it is conducted back to the river by a channel or pipe called a tailrace.

Station capacity can be large or small and is determined by the flow rate of the water and the vertical distance between the level of the source water and the outflow – or head.

Hydroelectric generation has a number of benefits. Since hydroelectric generation converts kinetic energy from the natural water cycle into electricity, it is a renewable source that does not create smog- or acid rain-causing atmospheric pollutants in its typical operations, or generate waste. Minimal GHGs result from normal biological processes occurring at hydro reservoirs, but life-cycle GHG emissions are similar to those of wind power, and much lower than those of thermal combustion plants.

On the economic side, although the upfront costs for constructing hydro generating stations can vary considerably and are generally high, operation and maintenance costs are generally low, and the lifetime of hydro plants is very long (e.g. the Petty Harbour Hydro-Electric Generating Station near St. John's has been generating electricity since 1900). As well, the cost of operating a hydroelectric plant is nearly immune to increases in the cost of fossil fuels such as oil, natural gas or coal, and no imports are needed.

In addition, hydro is a very reliable and predictable source of power. As a result of the longevity, reliability and flexibility of hydroelectric stations in Canada, hydro is one of the cheapest sources of electricity. According to the National Energy Board, Canada's reliance on hydroelectric generation is largely responsible for the country having some of the lowest electricity prices in the world[39].

NLH carries three hydro developments on the island in its generation portfolio for potential development. These projects have been screened and evaluated to be both economically viable and environmentally acceptable. Therefore, NLH has undertaken feasibility studies for the following three hydroelectric sites in its portfolio[40], all of which are applicable in both generation expansion alternatives and progressed to phase 2 screening.

<u>Island Pond</u>

Island Pond is a proposed 36 MW hydroelectric project located on the North Salmon River, within the watershed of the existing Bay d'Espoir development. The project would utilize approximately 25 metres of net head between the existing Meelpaeg Reservoir and Crooked Lake to produce an annual firm and average energy capability of 172 GWh and 186 GWh, respectively.

The development would include the construction of a three kilometre (km) diversion canal between Meelpaeg Reservoir and Island Pond, which would raise the water level in Island

---

[39] National Energy Board, *Frequently Asked Questions*, webpage, 2011
http://www.neb.gc.ca/clf-nsi/rnrgynfmtn/prcng/lctrct/frqntlskdqstn-eng.html

[40] (1) SNC-Lavalin Inc., *Studies for Island Pond Hydroelectric Project*, 2006 (Exhibit 5B)
(2) SNC-Lavalin Inc., *Feasibility Study for Portland Creek Hydroelectric Development*, 2007 (Exhibit 5C)
(3) SNC Lavalin Inc., *Feasibility Study Round Pond Development*, 1989 (Exhibit 5D[i])
(4) SNC Lavalin Inc., *Feasibility Study: Round Pond Hydroelectric Development*,1988 (Exhibit 5D[ii])

Pond to that of the Meelpaeg Reservoir. Also, approximately 3.4 kilometres of channel improvements would be constructed in the area. At the south end of Island Pond, a 750 m long forebay would pass water to the 23 m high earth dam, and then onto the intake and powerhouse finally discharging it into Crooked Lake via a 550 m long tailrace. The electricity would be produced by one 36 MW Kaplan turbine and generator assembly.

The facility would be connected to TL263, a nearby 230 kV transmission line connecting the Granite Canal Generating Station with the Upper Salmon Generating Station.

A final feasibility-level study and estimate, *Studies for Island Pond Hydroelectric Project*[41], was completed for NLH by independent consultants. The report prepared a construction ready update report including an updated capital cost estimate and construction schedule projecting approximately 42 months from the project release date to the in-service date. Figure 20 illustrates the Island Pond development.

Figure 20: Conceptual Sketch of Island Pond Development

Source: SNC-Lavalin Inc., *Studies for Island Pond Hydroelectric Project*, 2006

[41] SNC-Lavalin Inc., *Studies for Island Pond Hydroelectric Project*, 2006 (Exhibit 5B)

Portland Creek

Portland Creek is a proposed 23 MW hydroelectric project located on Main Port Brook, near Daniel's Harbour, on the Great Northern Peninsula. The project would utilize approximately 395 metres of net head between the head pond and outlet of Main Port Brook to produce an annual firm and average energy capability of 99 GWh and 142 GWh, respectively.

The project would require: a 320 m long diversion canal; three concrete dams; a 2,900 m penstock; a 27 km 66 kV transmission line from the project site to Peter's Barren Terminal Station; and the construction of access roads. The electricity would be produced by two 11.5 MW Pelton turbine and generator assemblies.

Figure 21: Conceptual Sketch of Portland Creek Hydroelectric Development

Source: NLH

The current schedule and capital cost estimate for Portland Creek is based on a January 2007 feasibility study, *Feasibility Study for: Portland Creek Hydroelectric Project*[42], prepared for NLH by independent consultants. The proposed construction schedule indicates a construction period of 32 months from the project release date to the in-service date. Figure 18 illustrates the Portland Creek development.

Round Pond

Round Pond is a proposed 18 MW hydroelectric project located within the watershed of the existing Bay d'Espoir development. The project would utilize the available net head between the existing Godaleich Pond and Long Pond Reservoir to produce an annual firm and average energy capability of 108 GWh and 139 GWh, respectively.

The current schedule and capital cost estimate for Round Pond is based on the 1988 feasibility study, *Round Pond Hydroelectric Development*[43], prepared for NLH by independent consultants, and the associated 1989 Summary Report based on the same. In the absence of any further work beyond what was identified in this study, the overall program for the Round Pond development is estimated to be completed in 33 months, including detailed engineering design.

Other Small Hydro

There are numerous undeveloped small hydroelectric sites on the island. An inventory of these sites was developed in a 1986 study undertaken for NLH by Shawmont Newfoundland. The extent to which a significant quantity of small hydro development can be accommodated is limited because the Newfoundland electricity system is currently isolated from the North American grid. The lack of interconnection to other systems introduces technical and operational system constraints which are generally related to the ability to provide capacity when it is required during peak periods.

Most of the remaining projects do not have storage capability and are referred to as "run of the river" facilities. Run of the river hydroelectric facilities have operating attributes very

---

[42] SNC-Lavalin Inc., *Feasibility Study for Portland Creek Hydroelectric Development*, 2007 (Exhibit 5C)

[43]
(1) SNC Lavalin Inc., *Feasibility Study Round Pond Development*, 1989 (Exhibit 5D[i])
(2) SNC Lavalin Inc., *Feasibility Study: Round Pond Hydroelectric Development*,1988 (Exhibit 5D[ii])

similar to wind generators as they only operate when there is water in the river and there is no certainty that the plants will be available to provide capacity at time of peak load.

In integrating small hydro and wind energy into the Newfoundland electricity system, planning and operational considerations to ensure reliable electricity supply are paramount. Both wind and run of river hydro are non-dispatchable; (meaning they only operate when either the wind is blowing or when there is water in the river). As discussed in Section 4.2.8 wind is quite variable, and while a run of the river project may be less variable, the fact that there is minimal or no storage means that there is no guarantee that the capacity will be available at time of peak when it is really needed. Also, river flows during the peak winter season are often lower than during any other season. Consequently, the run of the river project has less capacity and energy available when the system requires it most.

The successful integration of this technology is conditional upon an interconnection to a larger grid where there is sufficient low cost firm reserve capacity to compensate for the variability caused by the non-dispatchability of resources (i.e. the run of river technology). In the Isolated Island alternative the required firm reserve would be provided by Holyrood or some other thermal generating source, which diminishes much of the economic advantage of the non-dispatchable resource. Since no interconnections to other markets exist, opportunities to export surplus energy to other markets or to rely on other markets to support the island system do not exist.

Despite the concerns, as documented in Section 4.2.8, there is a limited capacity for the integration of a small amount of additional non-dispatchable resource in the Island Isolated alternative. Nalcor considered additional small hydro, but because of an economic preference for wind over small hydro, Nalcor has opted to use wind as the non-dispatchable generation of choice to be included in the Isolated Island alternative in phase 2 screening.

Small hydro development on the island of Newfoundland is not without controversy and an appreciable level of public opposition. In 1992 NLH Issued a Request for Proposals (RFP) for the purchase of up to 50 MW of small hydro production from NUGs. The process involved a preliminary screening process and at the final submission stage there were eleven project submitted for consideration. The majority of these projects were for developments that had been identified in the 1986 Shawmont Newfoundland study. NLH accepted four of the eleven proposals of which two were constructed - Star Lake 15 MW and Rattle Brook 4 MW. The others, Northwest River 12 MW and Southwest River 7 MW, were halted prior to construction due mainly to public opposition. Following this chain of events the Government of Newfoundland imposed a moratorium on further small hydro development in 1998. This moratorium is still in effect today.

Since the 1998 moratorium there has been very little activity around small hydro development. NLH has completed an analysis based on the 1992 RFP data that supports the decision to screen out the technology as an alternative for the Isolated Island alternative. The seven unsuccessful projects from the 1992 RFP can be considered to be representative of the most attractive of the remaining undeveloped small hydro on the island. Based on submission data these project had an average bid price of 6.64 cents per kWh (1992$), escalating this price to 2010$ using Nalcor's/NLH's "Hydraulic Plant Construction" escalation series, results in a current estimate of 10.4 cents per kWh (2010$). In comparison, NLH is carrying 9.2 cents per kWh (2010$) for the wind PPAs used in current modeling[44]. This indicates that NLH would pay a premium of approximately 13 percent for small hydro. The estimated costs reflect single small scale installations and while this would include basic grid interconnection it does not cover costs associated with major transmission upgrades that maybe required for larger or multiple small scale installations.

Based on these factors small hydro other than Island Pond, Portland Creek and Round Pond have been screened from further evaluation.

[44] Nalcor Energy, *Board Letter July 12th,2011, Information on Wind Farms*, 2011 (Exhibit 25)

4.2.13 Labrador Hydroelectric

Deferred Churchill Falls

In Phase 1 screening, consideration was afforded to a supply option that entailed a continuation of Holyrood operations and additional thermal generation as required for another three decades, and then to commission a transmission interconnection between Labrador and the island to avail of electricity production from the Churchill Falls hydroelectric generating facility in 2041 when the current long-term supply contract with Hydro Quebec terminates. This option did not advance beyond Phase 1 screening for the following reasons[45]:

1. There is inherent uncertainty around guaranteeing the availability of supply from Churchill Falls in 2041 because it is difficult to determine the environmental and policy frameworks that will be in place 30+ years out. There are other issues surrounding the CF asset with respect to Hydro Quebec, as Nalcor is not the sole shareholder of the Churchill Falls operation.

2. There is also significant risk associated with maintaining reliable supply through continued life extension measures for Holyrood generating station through to 2041. At that time, the first two units at Holyrood will be 70 years old.

3. Deferral of the interconnection would result in significantly higher rates for island consumers between now and 2041 and does not provide rate stability to island consumers as rates are tied to highly volatile fossil fuel prices for the first 30+ years of the study period along with escalating maintenance costs for Holyrood and an increasing likelihood that replacement of the plant will be required prior to 2041.

4. Island customers will remain dependent on fossil fuel generation for the first 30+ years of the study resulting in continued and increasing GHG emissions. Given the

---

[45] Nalcor response to MHI-Nalcor-3

Government of Canada's decision to introduce GHG emissions regulation for coal fired generating stations, Nalcor's ability to refurbish Holyrood without conforming to GHG emissions regulation is doubtful, and replacement of the plant may be required between now and 2041.

5. Each of the screening criteria above has significant risk and uncertainty that are not present in either the Isolated or Interconnected Island alternatives.

   The prospect of requiring substantial investment to Holyrood to extend its life beyond that contemplated in the Isolated Scenario, or the real possibility of requiring replacement of Holyrood and then retiring it in 2041, increases the probability that this option will be substantially more expensive than projected.

The deferral of construction of Muskrat Falls and the Labrador Island Transmission Link introduces other economic disadvantages:

1. Value is lost by the Province through the deferral of monetization of Newfoundland and Labrador's energy warehouse. The revenue benefits of Muskrat Falls, Gull Island, other wind and small hydro developments throughout the Province will be foregone, thus reducing government's ability to invest in infrastructure and to provide services. Revenue that could have been used to fund long-term assets and infrastructure will have been used to purchase imported oil.

2. Economic and employment benefits from domestic economic activity associated with domestic energy construction projects will be foregone for decades.

In addition, NLH completed a *Strategist®* analysis for a generation expansion plan that includes the deferred transmission interconnection with Labrador coupled with the supply of energy from Churchill Falls in 2041. While this option did not make it beyond phase 1 screening, it was ran in *Strategist®* as a sensitivity and the CPW results, which are presented in Section 7, confirm the decision not to pursue this option further..

Recall Power from Churchill Falls

Under the existing power contract between Hydro Quebec and Churchill Falls (Labrador) Corporation, there is a provision for a 300 MW block of power which can be recalled for use in Labrador. The 300 MW block is sold to NLH in its entirety. NLH meets the needs of its customers in Labrador first and then sells any surplus energy into export markets.

In addition to its domestic and general service customers in Labrador, NLH has contracts with:

- the Iron Ore Company of Canada for 62 MW of firm power, 5 MW interruptible and secondary power if available, and
- the Department of National Defense in Goose Bay for 23 MW of secondary power.

In 2010, approximately 38 percent of the energy available under the 300 MW recall contract was sold in Labrador, with the unused balance being sold into short term export markets. On average in the winter almost 220 MW of power is used to meet demand in Labrador. With only 80 MW of recall power available in the winter, there is insufficient firm capacity and energy available to meet the island's electricity needs and to displace the Holyrood Plant, which generates almost 500 MW at the time of highest (winter) need for the province. The use of recall power was therefore screened out during phase 1 as an alternative supply option for the Island.

Gull Island

Gull Island is a 2,250 MW hydroelectric generation project on the Churchill River with an average annual energy capability of 11.9 TWh. Located 225 kilometers downstream from the existing Churchill Falls power plant, Gull Island has been extensively studied over the years and the engineering work completed has led to a high level of confidence in the planned design and optimization of the facility.

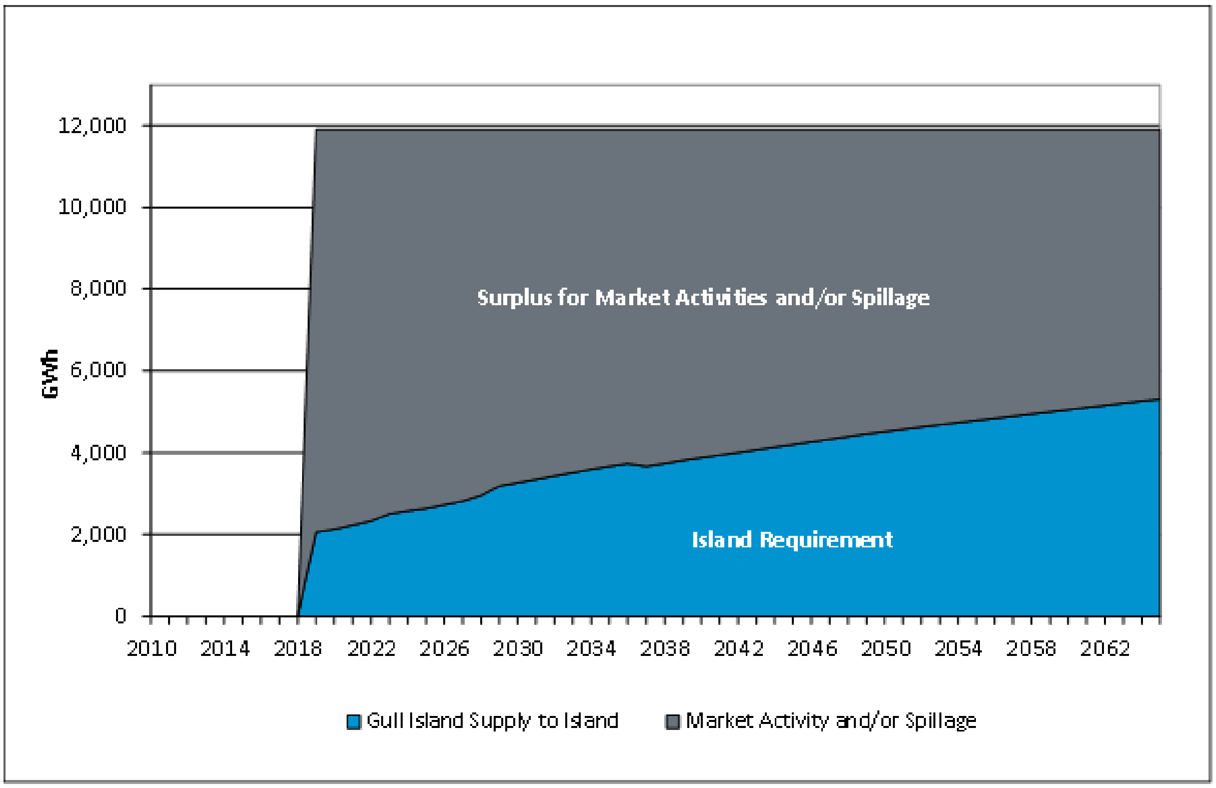
Gull Island is the larger of the two Lower Churchill sites. While offering more favourable economies of scale than Muskrat Falls, and therefore a lower unit cost per MWh of production, if all of the output was assumed sold or used, Gull Island requires significantly greater capital investment. The scale of Gull Island output creates a requirement to either negotiate with neighbouring utilities for export contracts, attract investments in energy intensive industries, or to participate directly in regional wholesale markets to attain the full utilization unit cost. If such opportunities do not exist, and island supply is the only available market, then the total cost for Gull Island has to be spread over a smaller block of utilized energy. This makes the actual unit cost of Gull Island greater than Muskrat Falls.

Figure 22 shows the forecasted energy requirement for the island against the annual output for Gull Island. Initially, the island would require less than 20 percent of Gull Island's annual production, growing to about 45 percent by 2065. The development of Gull Island is therefore linked to either the successful negotiation of both power sales agreements and transmission service arrangements for exports, or a very significant increase in industrial load in the province, or a combination of both. Because of the magnitude of the investment associated with Gull Island, compared to that of Muskrat Falls, greater certainty is required for these arrangements in advance of sanctioning the project in order meet the requirements of potential lenders to the project.

Historically there were no open transmission services available in Canada. Labrador hydroelectric potential was geographically isolated from larger power markets with the exception of Quebec. Over the past many years there have been a number of unsuccessful efforts to negotiate power sales arrangements with Hydro Quebec and to attract energy intensive industry to the province, especially aluminum smelting.

The unbundling of the electricity industry into its primary services, and introduction of wholesale competition in US electricity markets in the latter 1990's, required the adoption of open non-discriminatory transmission access to facilitate competition in the industry. The US Federal Energy Regulatory Commission (FERC), which has jurisdiction over US wholesale electricity trade, has adopted multiple rules designed to prevent undue discrimination and the exercise of market power in order to ensure fair and competitive markets. All market participants owing transmission facilities have to conform to these rules and must demonstrate they are providing open non-discriminatory transmission access to third parties. The adoption of open access transmission tariffs marked a milestone change for the electricity sector. Hydro Quebec is now required to provide open transmission access on its transmission grid in return for being able to participate in the wholesale electricity market in the Northeast US. While there is no Canadian federal regulator with jurisdiction to ensure open and fair access over all transmission in Canada, the US FERC does have jurisdiction over the US activities of Canadian entities that participate in US competitive wholesale markets.

Figure 22: Island-Labrador Electricity Supply Balance with Gull Island



Source: Nalcor Energy, *Energy Over the Infeed/ Labrador HVdc Analysis 2010 – Input to NLH Generation Planning Analysis*, 2010 (Exhibit 6B)

NLH, and subsequently Nalcor, have followed these market developments closely. In 2006 NLH made an application to Hydro Quebec for transmission service for output from the Lower Churchill Project to multiple markets in accordance with open access rules. This started a multi-stage study process that ultimately would normally have led to a transmission service agreement. NLH was not satisfied that Hydro Quebec was adhering to its own open access rules and procedures and filed formal complaints with the Quebec

Energy Regulator (the Regie de l'energie). This led to a prolonged regulatory complaint hearing process that culminated in decisions against NLH. In 2010, NLH sought a revision of the Regie's decisions on grounds that they contained fundamental errors. In 2011, this application was denied. NLH subsequently has filed an application for judicial review by the Quebec Superior Court of the Regie's decisions on grounds that the Regie committed fundamental errors in terms of procedure and in the application of Hydro Quebec's open access rules.

NLH has invested significant time and resources in PPA negotiations and in seeking transmission access in accordance with open access rules on the Hydro Quebec transmission system. Nalcor will continue to avail of all appropriate channels to obtain the firm transmission services required to develop an export sales portfolio for the Gull Island project. However, in the absence of the required certainty on being able to access export markets and sell surplus production, it would not be prudent at this time to propose project sanction for the Gull Island project. Similarly, in the absence of substantive commitments from new or existing industrial interests requiring major new power and energy requirements, it is again not prudent for Nalcor to advance Gull Island further at this time.

Because of the large scale of production and investment associated with the Gull Island development, firm transmission access to export markets is required since the internal provincial requirements account for a relatively small percentage of the output for many years. In the absence of such firm transmission service, reasonable financing of Gull Island would be unlikely.

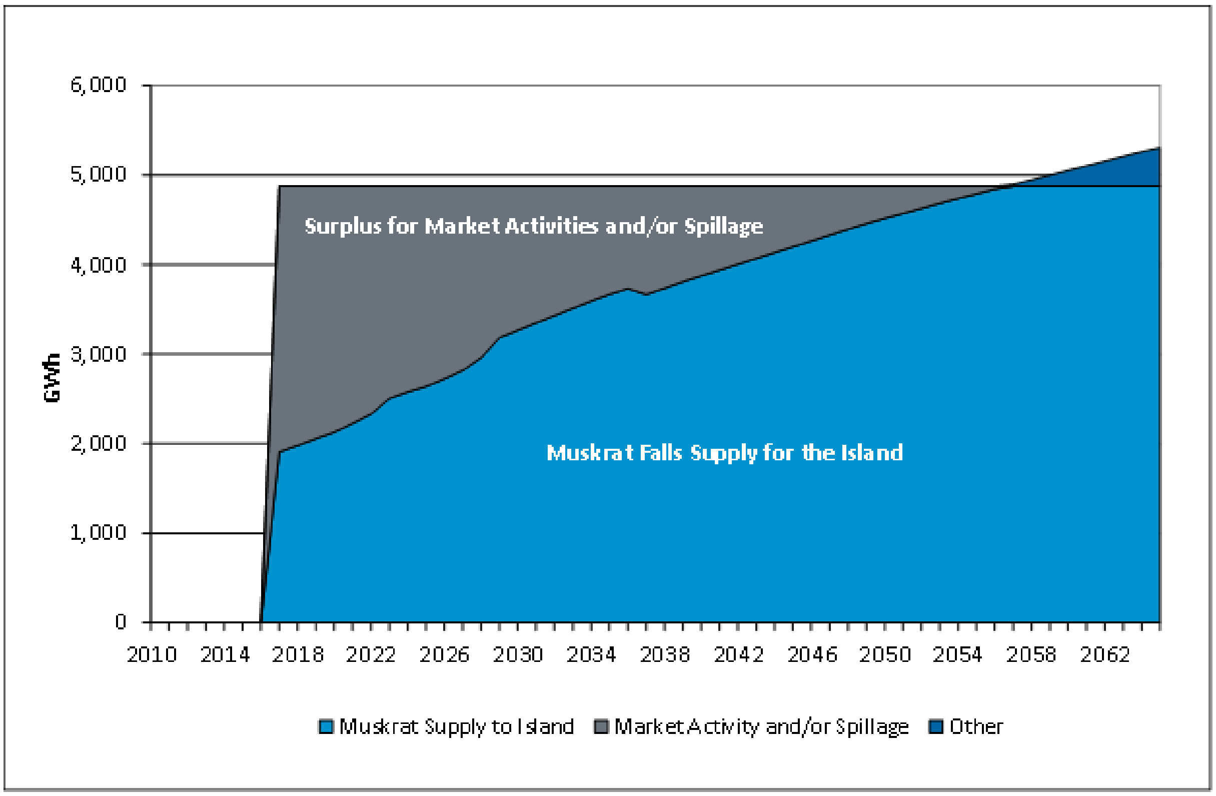
As a result of the high unit cost of energy without external sales or other new usage compared to Muskrat Falls, the absence of firm transmission access to export markets at this time and the difficulty of arranging financing in such an environment, Gull Island did not advance past the Phase 1 screening of alternatives.

Muskrat Falls

The hydroelectric generation site at Muskrat Falls on the Churchill River is an 824 MW facility with an average energy capability of 4.9 TWh per year.

Figure 23 provides the forecast requirements for the island relative to the output of muskrat falls across the planning period. The island can initially use about 40 percent of Muskrat falls supply in the early years following commissioning, increasing steady in line with the island's economic growth and so that by the mid 2050's, 100 percent of the Muskrat Falls production would be used within the province.

Figure 23: Island-Labrador Electricity Supply Balance with Muskrat Falls



Source: Nalcor Energy, *Energy Over the Infeed/ Labrador HVdc Analysis 2010 – Input to NLH Generation Planning Analysis*, 2010 (Exhibit 6B)

As noted in the previous Gull Island section, the unit cost of Muskrat Falls, assuming no value for the unutilized energy, is lower than Gull Island unit cost under the same assumption. Muskrat Falls offers an appropriately sized indigenous and renewable generation project to address the internal energy requirements for the province in the foreseeable future. Surpluses in the initial years can be used for additional local requirements or sold, as possible, into short term export markets. The Muskrat Falls supply option cleared Phase 1 screening for input to further system planning analysis. More details on the Muskrat Falls development are provided in Volume 2.

4.2.14 Electricity Imports

As an alternative to the development of indigenous resources and facilities, NLH could construct a transmission interconnection to regional electricity markets and to then import its power and energy requirement to displace thermal production at Holyrood and meet the incremental growth in electricity demand for the province. Two configurations were considered for phase 1 screening in this regard;

- a transmission interconnection from Churchill Falls to the island, and
- a transmission interconnection from the Maritimes to the island.

For purposes of the screening review, energy was assumed to be ultimately sourced from the New York and New England markets respectively as both regions have competitive wholesale generation markets.

Unrestricted access to firm transmission services were assumed to be available across intervening jurisdictions of Quebec and New Brunswick/ Nova Scotia respectively. Accordingly, the extent of transmission system reinforcements that may be required, for example, across Nova Scotia and New Brunswick is unknown, and could not be determined for the screening review. The prevailing assumption was that the existing Open Access Transmission Tariffs for Nova Scotia and New Brunswick, or for Quebec, would be the only external transmission expenses to apply.

Each HVdc interconnection configuration would terminate at Soldiers Pond, adjacent to the Avalon load center, consistent with the Labrador-Island Link. As load on the island grows, increasing firm transmission capacity would be required.

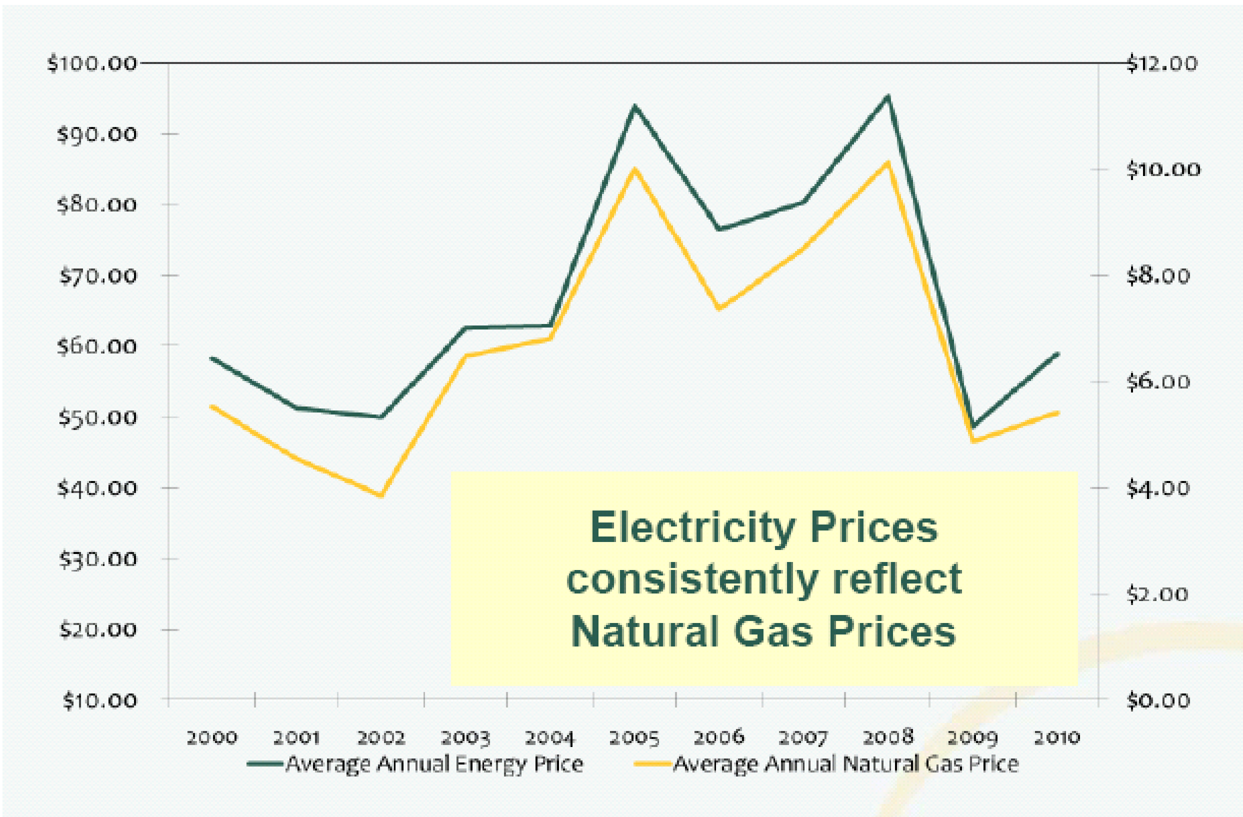
Reliance on electricity imports raised the following considerations in phase 1 screening:

- Exposure to price volatility or significant price premiums
- Security of supply – short- and long-term
- Potential market structural/ transmission impediments

Price Volatility

Natural gas-fired generation is typically the marginal supply source and price setter in both the New York and New England wholesale generation markets, as is evident in Figures 24 and 25.

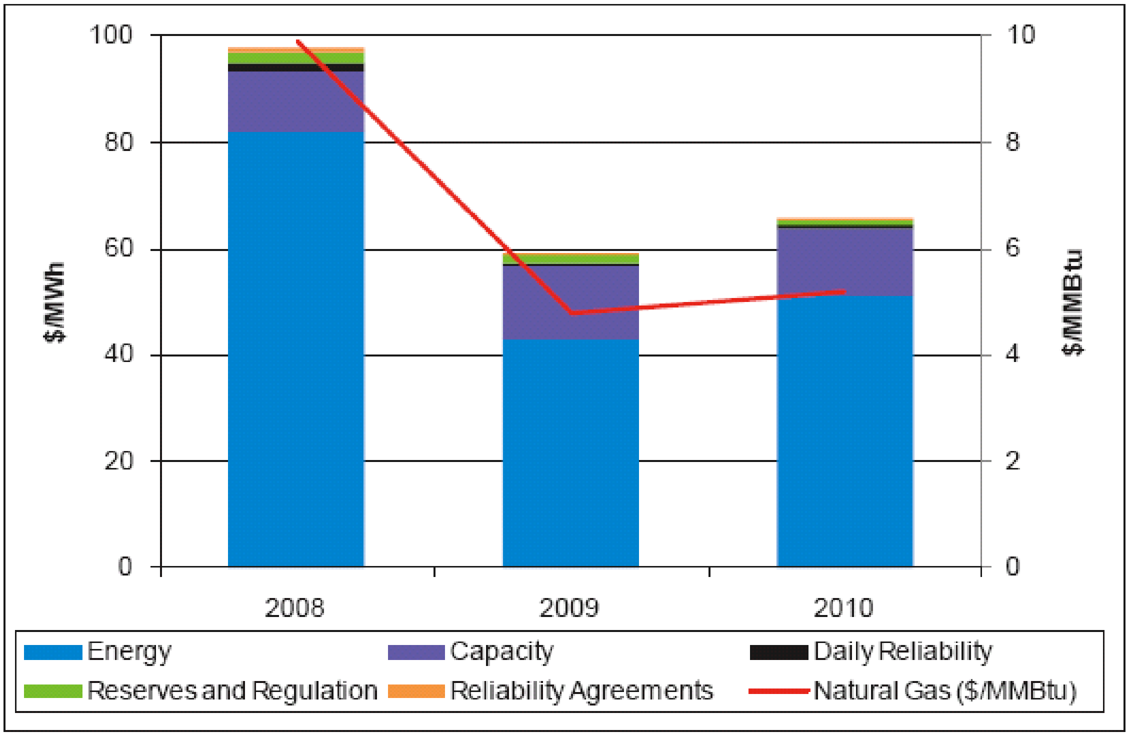
Figure 24: Annual Average Electricity Prices and Natural Gas Prices in New York State



Source: New York Independent System Operator, *Power Trends 2011 Presentation*, 2011
http://www.nyiso.com/public/webdocs/newsroom/power_trends/Power_Trends_2011_Presentation.pdf

As a result of the strong correlation between electricity market clearing prices and natural gas prices, these wholesale market prices are exposed to gas price volatility. In addition to gas price volatility, many other local variables affect the short term clearing prices in these markets, including weather conditions impacting peak demand, unplanned generation or transmission outages, and transmission congestion.

Figure 25: All in Cost of Electricity in New England and Natural Gas Prices in New England



Source: ISO New England, *2010 Annual Markets Report*, 2011
http://www.iso-ne.com/markets/mkt_anlys_rpts/annl_mkt_rpts/2010/amr10_final_060311.pdf

Security of Supply

Security of supply is continuously assessed by the System Operators in these regions. The latest market reports[46] indicate that the economic recession has had a significant impact on load in the region, thus providing short term assurance of the adequacy of supply to meet forecast market requirements. However, beyond 2015, both New England and New York are facing potentially significant plant retirements, both because of the age of the generation fleet and because a significant proportion of the baseload generators in the region are carbon fueled (coal and gas in particular). In New York 60 percent of installed generation is pre 1980's generation[47] and 53 percent of capacity is oil or coal fired[48] . The New York

[46](1) ISO New England, *2011 Regional System Plan*, 2011
http://www.iso-ne.com/trans/rsp/index.html
(2) New York Independent System Operator, *Power Trends 2011*, 2011
http://www.nyiso.com/public/webdocs/newsroom/power_trends/Power_Trends_2011.pdf

[47] New York Independent System Operator, *Power Trends 2011 Presentation*, 2011
http://www.nyiso.com/public/webdocs/newsroom/power_trends/Power_Trends_2011_Presentation.pdf

[48] Ibid.

Independent System Operator predicts that almost 24,000 MW of generation capacity will be impacted by the more stringent Environmental Protection Agency (EPA) regulations. As a result of the required expenditures to achieve compliance, certain older facilities may be no longer competitive and forced to close. In New England, coal and oil generation comprise 9,604 MW or 30 percent of generation capacity. The New England system operator reports estimates for retirements or de-ratings in the range of 5,800 MW to 8,700 MW resulting from EPA rules[49].

Plant retirements and/or de-rating across the region have implications for the availability and price of supply and are risks which are introduced as a result of relying on imports as a long-term supply source of the province.

Potential Market Structural and Transmission Impediments

While reliance on imports reduces control over security of supply, some of this may also be a result of how electricity markets are structured and function. For example in the New England and New York markets there are currently no long-term physical transmission rights (beyond 1 to 2 years), thereby complicating the process of transmitting energy from a power plant in the market to an external customer. While the System Operators are working on addressing this issue it is currently a consideration.

In summary, as a result of the risks outlined on price volatility, security of long-term supply, and transmission impediments, the reliance on electricity imports as a long-term supply option for the island was not considered further following phase 1 screening.

4.3 Summary of Supply Options and Initial Screening

Table 21 summarizes the power supply options considered by NLH in its assessment of long-term generation expansion alternatives for the future supply of power and energy for the province in general and for the island of Newfoundland in particular.

[49] ISO New England, *2011 Regional System Plan*, 2011
http://www.iso-ne.com/trans/rsp/index.html

Table 21: Summary of Power Generation Supply Options and Initial Screening

Power Generation Option	Isolated Island	Interconnected Island
Nuclear	✗	✗
Natural Gas	✗	✗
Liquefied Natural Gas (LNG)	✗	✗
Coal	✗	✗
Combustion Turbines (CTs)	✓	✓
Combined Cycle (CCCTs)	✓	✓
Wind	✓	✓
Biomass	✗	✗
Solar	✗	✗
Wave/Tidal	✗	✗
Island Hydroelectric	✓	✓
Labrador Hydroelectric	N/A	✓
Electricity Imports	N/A	✗
Transmission Interconnection	N/A	✓

Source: Nalcor Energy

As stated at the outset in Section 4, NLH applied a high level of scrutiny to the screening around security of supply and reliability and this level of scrutiny is deemed necessary because NLH has to demonstrate with confidence that it can fulfill its mandate. The generation supply options that passed the initial screening were included in the portfolio of options that the *Strategist®* utility power system planning software optimized for the least cost objective function subject to certain constraints like the presence or absence of resources associated with the Lower Churchill Project.

5.0 Isolated Island Alternative - Phase 2

The next step in the electric power system planning process involves the development of optimized least cost generation expansions plans in *Strategist®* for the Isolated Island supply alternatives that have advanced through Phase 1, while adhering to the generation and transmission planning criteria and the resource development constraints. The isolated expansion plan is characterized by a continued development of indigenous renewable resources but with a progressive reliance on thermal power across the planning period. This section provides the Isolated Island generation expansion plan along with its accompanying transmission planning considerations. The *Strategist®* CPW value for this alternative is presented along with supplementary information concerning Holyrood pollution abatement, GHG risk, and plant life extension.

5.1 Isolated Island Generation Expansion Plan

The Isolated Island alternative is an optimization of proven technologies and supply options that passed through the initial screening and that have been engineered to a level sufficient to ensure they can meet the required expectations from reliability, environmental and operational perspectives. There is a high level of certainty that all elements can be permitted, constructed and integrated successfully with existing operations.

The Isolated Island alternative is a least cost optimization of all costs associated with the development of further island hydroelectric facilities, additional wind supply, and a combination of replacement capital for existing thermal facilities and the construction of new thermal resources utilizing fossil fuels purchased in global oil markets. Important capital and operating components of the Isolated Island alternative rest with pollution abatement technologies for the Holyrood Plant as well as the subsequent installation of CCCT technology utilizing LFO for growth as well as for the replacement of the Holyrood Plant.

The generation expansion plan for the Isolated Island alternative is a continuation of the status quo that relies on the continued operation of the Holyrood Plant. In addition, the generation alternatives available from those not screened out in Section 4 are also available for inclusion in the expansion plan. These include:

1) Small hydroelectric developments, and more specifically, Portland Creek, Island Pond, and Round Pond,
2) Wind generation limited to be within existing economic constraints,
3) Simple cycle combustion turbines (CTs),
4) Combined cycle combustion turbines CCCTs).

The *Strategist®* software was used to develop the least cost Isolated Island expansion plan. The system additions are listed in Table 22 and have been characterized as generation planning criteria-driven investments versus life extension and replacement capital.

The Isolated Island expansion plan includes multiple capital expenditures driven by the planning criteria mostly due to load growth. These include the addition of the 36 MW Island Pond and 18 MW Round Pond which benefit from the reservoir storage available through the existing Bay d'Espoir system. These facilities offer firm capacity which is beneficial for the Isolated Island generation expansion plan. As well, the 23 MW Portland Creek plant on the Northern Peninsula will produce an annual firm and average energy capability of 99 GWh and 142 GWh, respectively. The Isolated Island alternative will also benefit from the continued operation of existing wind farms. The possibility of additional wind capacity in the Isolated Island alternative has been treated as a sensitivity analysis and is discussed further in Section 7.2. The Isolated Island expansion plan will also require significant investment to meet life extension and environmental upgrade requirements at the Holyrood Plant and replacement of the existing wind farms.

1 **Table 22: Isolated Island Alternative – Installations, Life Extensions and Retirements**
2 **(In-service capital costs; $millions nominal)**

	Criteria Driven		Life Extension/ Replacement		Retirements
Year	**Description**	**Cost**	**Description**	**Cost**	**Description**
2014	25 MW Wind	PPA			
2015	36 MW Island Pond	$199	Holyrood ESP & Scrubbers	$582	
2016			Holyrood Upgrade	$100	
2017			Holyrood Low No_x Burners	$20	
2018	23 MW Portland Creek	$111			
2019			Holyrood Upgrade	$121	
2020	18 MW Round Pond	$185			
2022	170 MW CCCT	$282			Hardwoods CT (50 MW) Corner Brook Pulp and Paper Co-Generation (PPA)
2024	50 MW CT	$91	Holyrood Upgrade	$9	Stephenville CT (50 MW)
2027	50 MW CT	$97			
2028			Replace 2 Existing Wind Farms (~54 MW)	$189	2 * 27 MW Wind farms (PPA)
2029			Holyrood Upgrade	$4	
2030	50 MW CT	$103			
2033	Holyrood Replacement (2 units) 170 MW CCCT 170 MW CCCT	 $464 $346			Holyrood Unit 1 (161.5 MW) Holyrood Unit 2 (161.5 MW)
2034			Replace 2014 Wind Farm (~25 MW)	$98	25 MW Wind (PPA)
2036	Holyrood Replacement (3rd unit) 170 MW CCCT	$492			Holyrood Unit 3 (142.5 MW)
2042	50 MW CT	$130			
2046	50 MW CT	$141			
2048			Replace 2 Existing Wind Farms (~54 MW)	$281	2 * 27 MW Wind farms
2049	50 MW CT	$149			50 MW CT
2050	170 MW CCCT	$477			
2052	170 MW CCCT	$665			50 MW CT & 170 MW CCCT
2054			Replace 2034 Wind Farm (~25 MW)	$146	25 MW Wind
2055					50 MW CT
2056	170 MW CCCT	$534			
2063	50 MW CT 50 MW CT 170 MW CCCT	$197 $197 $818			2 * 170 MW CCCT
2064	50 MW CT	$201			
2066	170 MW CCCT	$645			170 MW CCCT
2067	170 MW CCCT	$882			50 MW CT

3 Source: NLH, *2010 PLF Strategist Generation Expansion Plans*, 2011 (Exhibit 14)

As a result of the reliance on thermal generation, this alternative carries fuel price volatility and risk and also exposure to potential carbon costs related to greenhouse gas emissions. Nalcor has conducted sensitivities related to fuel price and potential carbon costs which can be found in Section 7.2.

5.2 Isolated Island Transmission

Generation Integration

The Isolated Island alternative includes the 36 MW Island Pond, 23 MW Portland Creek and 18 MW Round Pond developments. It is these three developments that will have the most significant impact on the Isolated Island transmission expansion plan.

At present the Bay d'Espoir 230 kV transmission system consists of two 230 kV transmission lines connecting up stream generating stations at Granite Canal and Upper Salmon to the Bay d'Espoir Terminal Station and island Grid, TL234 (Upper Salmon to Bay d'Espoir) and TL263 (Granite Canal to Upper Salmon). The 36 MW Island Pond Development will connect to the island grid via routing of TL 263 in and out of Island Pond on its way to Granite Canal. The integration of Island Pond development into the existing 230 kV TL234/TL263 collector network complies with the existing transmission planning criteria.

The proposed Round Pond development is also located in the Bay d'Espoir water system. At an 18 MW capacity it is proposed to build a 69 kV transmission line from the site to the Bay d'Espoir Terminal Station rather than grid tie at the 230 kV level. The single 69 kV transmission line to connect the Round Pond plant meets the existing transmission planning criteria.

The 23 MW Portland Creek development situated on the Great Northern Peninsula will connect to the existing Peter's Barren Terminal Station via a single 66 kV transmission line and the Portland Creek interconnection complies with all transmission planning criteria.

All costs associated with the interconnection have been included in the generation project costs estimates.

Bulk Transmission System

As indicated in the Island Transmission System Outlook[50], the 230 kV transmission system between Bay d'Espoir and the St. John's load center is both thermally and voltage constrained with respect to increased power transfers onto the Avalon Peninsula. In the context of the Isolated Island alternative with the hydroelectric developments at Portland Creek, Island Pond and Round Pond located in central and west while the load center is located on the Avalon Peninsula, the third 230 kV transmission line from Bay d'Espoir to the Avalon Peninsula is required to increase power transfers to the load center while meeting the transmission planning criteria. The new 230 kV transmission line will provide the necessary voltage support and thermal transfer capacity to deliver the new off Avalon Peninsula generation supply to the load center. The costs associated with the new 230 kV transmission line between Bay d'Espoir and the Avalon Peninsula are common to both the Isolated Island and Interconnected Island alternatives. Therefore these costs are excluded from the *Strategist®* analysis itself. However, such common costs are included in NLH's total revenue requirement calculations.

5.3 Isolated Island CPW

The CPW for the Isolated Island alternative is $8,810 million (2010$). This CPW value embodies all of the incremental operating and capital expenses associated with meeting forecasted load to 2067 arising from the utility isolated expansion plan as presented in Section 5.1. This CPW can be partitioned according to the cost categories outlined in Table 23 and Figure 26.

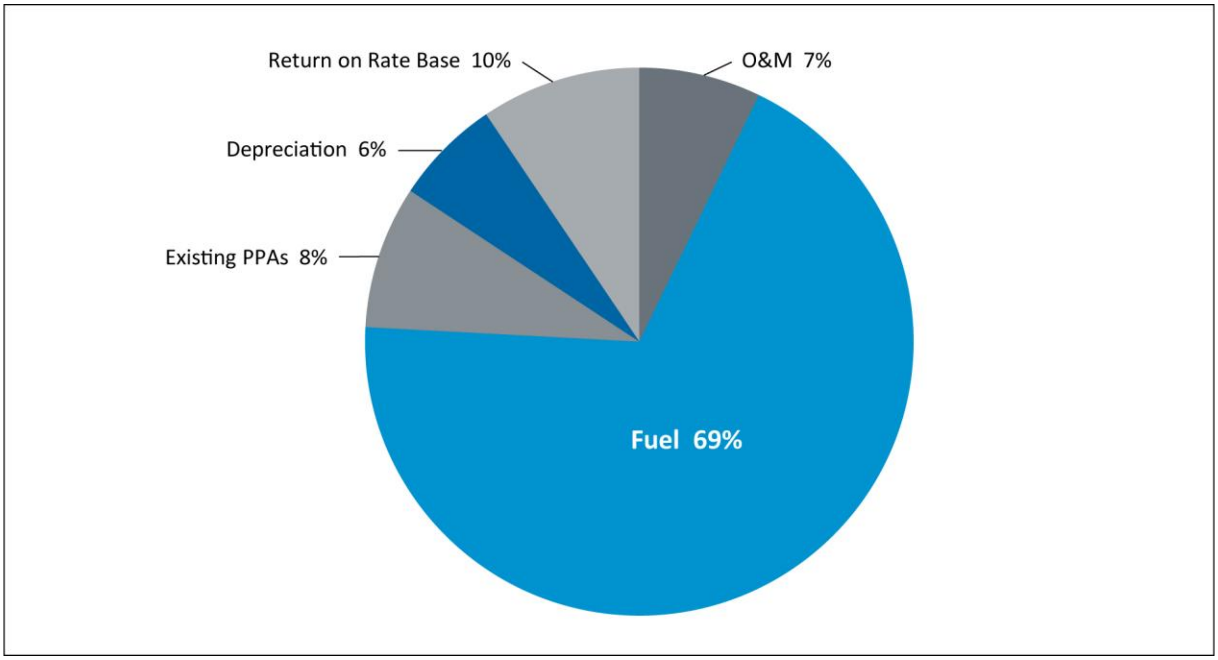
Table 23: Isolated Island Alternative: Generation Expansion CPW (2010$, millions)

	O&M	Fuel	Existing PPAs	Depreciation	Return on Rate Base	Total
Isolated Island	$634	$6,048	$743	$553	$831	$8,810
% of Total CPW	7.2%	68.7%	8.4%	6.3%	9.4%	100%

Source: Nalcor response to MHI-Nalcor-1

[50] NLH, *Island Transmission System Outlook*, 2010 (Exhibit 24)

Figure 26: Isolated Island Alternative CPW Breakdown (% of total)

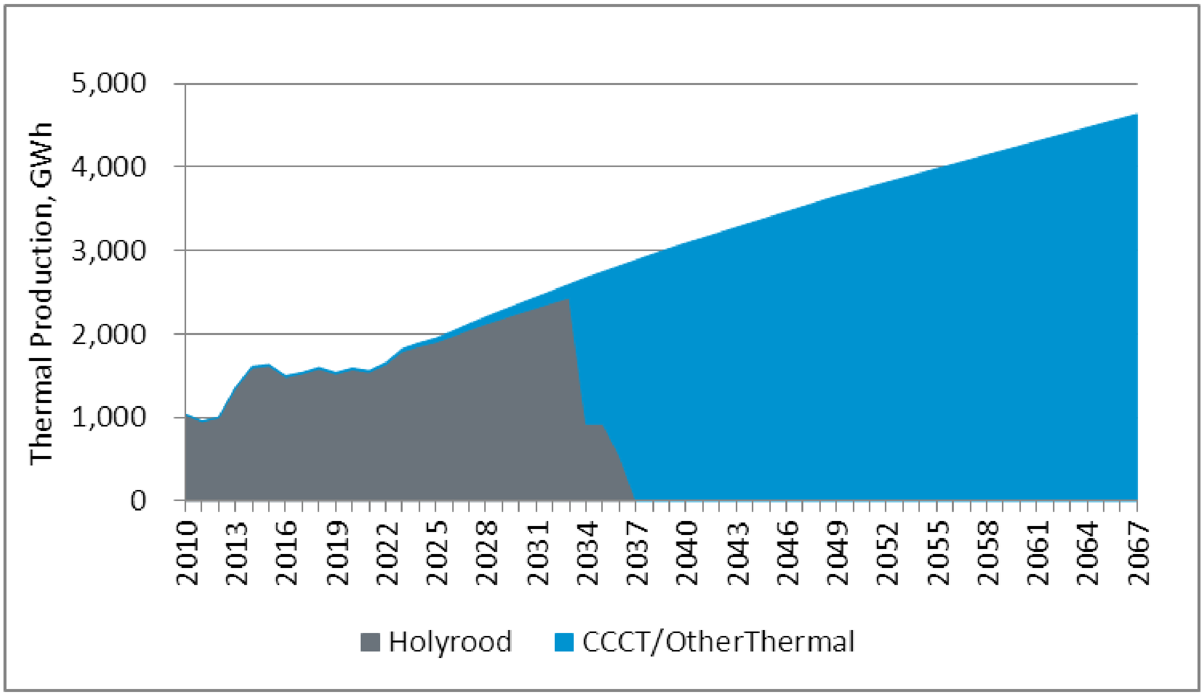


Source: Nalcor response to MHI-Nalcor-1

The segmentation of CPW by major production cost component makes clear the future extensive dependence on internationally priced fossil fuels, accounting for almost 70 percent of NLH's total incremental production costs going forward. This dependence arises due to the limited indigenous alternatives that can be technically, and/or reliably drawn upon to support an Isolated Island economy in the future. These costs relate to thermal fuel requirements both from the Holyrood Plant up until its retirement, and from CCCT and CT thermal generating units as required going forward to meet load growth and for replacement of obsolete plant. Figure 27 provides the thermal power production required for the Isolated Island alternative across the planning period. At present approximately 15% of NLH electricity production is sourced to thermal production while at the end of the planning period, about 40% of its production is projected to be thermal based[51].

[51] Nalcor response to MHI-Nalcor-97a

Figure 27: Thermal Production Required – Isolated Island Alternative



Source: Nalcor response to MHI-Nalcor-49.1

5.4 Holyrood Pollution Abatement and Life Extension

Because of the importance of continued and reliable operations at Holyrood, additional detailed information is provided below on the issues of Holyrood pollution abatement, GHG risk, and life extension.

Holyrood Pollution Abatement

The Holyrood oil-fired facility does not have any environmental equipment for controlling particulate emissions or SO_2. In order to meet the commitments of the Energy Plan to address emission levels at the facility in the absence of the Lower Churchill project, NLH has identified ESPs and wet limestone FGD systems as the Best Available Control Technology (BACT) to control particulate and SO_2 emissions from the plant. These technologies are mature and reliable. Such pollution abatement technologies provide the Holyrood Plant with operational fuel flexibility.

Electrostatic precipitators (ESP's) negatively charge the ash particles and collect them on positively charged collecting plates. The plates are rapped and the ash is collected in hoppers where it is then transported to storage. ESP's have been in application for over thirty years and are the standard for collecting fly ash from a power station's flue gas stream. ESP's have typical collection efficiencies of 95 percent+ for an oil-fired station.

NOx emissions are a function of the fuel combustion characteristics and boiler operation. The installation of the ESPs and FGD system at the Holyrood Plant would have no impact on NOx emissions at the station. For this reason, NLH has included low NOx burners to complete the scope of achievable environmental abatement for the Holyrood Plant.

The addition of FGD and ESP will increase station service power demand at the Holyrood Plant and increase O&M costs. In addition a large waste disposal facility must be developed to contain waste from FGD and ESP and there will be an increase in regional truck traffic and on site heavy equipment. The in-service capital costs for the Holyrood Plant's pollution abatement program are summarized in Table 24.

Table 24: Holyrood Pollution Abatement Capital Costs

Item	In-Service Capital Cost ($millions)
Flue Gas Desulphurization & Electrostatic Precipitators	$582
Low NOx Burners	$20
Total	**$602**

Source: Stantec Consulting Ltd., *Precipitator and* Scrubber *Installation Study HTGS*, 2008 (Exhibit 5L[i])

These capital costs, and associated provisions for operating costs, are included in the Isolated Island generation expansion plan. It is important to note that these pollution abatement controls do not reduce GHG emissions. An increase in station service load at the Holyrood Plant associated with FGD operations will actually increase overall GHG emissions.

In the absence of pollution abatement and control technology at the Holyrood Plant, in 2006 NLH commenced burning one percent sulphur No. 6 fuel oil in order to reduce emissions. This improved fuel grade reduced SO_2 and other non GHG emissions by about 50 percent. In 2009, NLH improved its heavy fuel oil grade to 0.7 percent sulphur to reduce emissions by a further 30 percent.

<u>Holyrood Greenhouse Gas Emissions and Production Costing Risk</u>

GHG emissions and their impact on global warming is another prominent environmental issue. Carbon dioxide is the primary GHG of concern and the Holyrood Plant emits CO_2 in direct proportion to its production of thermal based electricity. The regulation of GHG could have a significant adverse impact on production costing and future generation planning decisions.

Federal regulatory action against GHG emitting facilities is increasingly likely. There is a risk that a facility such as the Holyrood Plant could not legally operate if a natural gas combined cycle benchmark for GHG emission intensity levels is applied to oil fired generation. The Government of Canada has gazetted its proposed GHG regulations for coal fired generating facilities and they tie continued operation of these facilities to meeting the natural gas combined cycle benchmark[52]. Under the proposed regulations, coal facilities that are commissioned prior to July 1, 2015 and have reached the end of their 45 year design life, may receive an exemption to continue operation until 2025, provided they incorporate carbon capture and storage (CCS) technology to reduce their emissions intensity to that of a natural gas fired generating facility. New facilities (those commissioned on or after July 1, 2015) that incorporate CCS technology can apply for a deferral of application of the standard to 2025.

Since the GHG intensity of heavy fuel oil is 77 percent of coal and 2.2 times higher than natural gas, NLH expects the Government of Canada will impose limitations on heavy fuel oil fired generating facilities that are similar to those proposed for coal fired generation. NLH has not completed any studies to consider the implementation of CCS at the Holyrood Plant, but notes that SaskPower has initiated a $1.2 billion project to implement CCS demonstration project on Unit 3 of SaskPower's Boundary Dam thermal facility[53]. Based on these considerations NLH believes there is a risk that the Holyrood plant will not be permitted to operate in its current manner at some point in the next 30 years until 2041.

[52] Government of Canada, *Canada Gazette Part I, August 27, 2011*, 2011 (Exhibit 107)

[53] SaskPower, *Boundary Dam Integrated Carbon Capture and Storage (BD3 ICCS) Demonstration Project*, webpage, 2011 http://www.saskpower.com/sustainable_growth/assets/clean_coal_information_sheet.pdf

<u>Holyrood Operations under the Isolated Island Alternative</u>

If the Holyrood plant is required to continue operating as a base loaded thermal generating station after 2016/2017, which would be the circumstance in an Isolated Island supply future, extensive and comprehensive investigative work will be required to assess the cost of significantly extending the operating life of the thermal generating systems compared to other alternatives.

For the 2010 generation expansion analysis, an Isolated Island alternative assumed that the Holyrood plant would continue to operate as a generating station until the mid 2030's at which time it would be retired (2033 for Units 1 and 2 and 2036 for Unit 3) and replaced with combined cycle units using LFO. NLH engineering and operating experience and expertise was used to formulate an upgrade program to see the Holyrood plant through to it targeted retirement dates. Under the Isolated Island alternative, capital upgrades included in the *Strategist®* analysis for the Holyrood plant total $233 million between 2011 and 2029.

Table 25: Holyrood Life Extension Capital

Project	In Service Year	In Service Cost ($ millions)
Upgrade 1	2016	100.0
Upgrade 2	2019	121.0
Upgrade 3	2024	8.5
Upgrade 4	2029	3.6
Total		**233.1**

Source: Nalcor response to MHI-Nalcor-49.3

5.5 Summary

The preparation of a least cost generation and transmission plan for the Isolated Island alternative in Phase 2 results in a CPW of $8,810 million ($2010, present value). The development of indigenous renewal resources does not avoid a progressive dependence on thermal energy for the island portion of the province. Keys risks for the Isolated Island alternative are world oil prices and environmental costs associated with thermal electricity generation, initially with the existing Holyrood plant, and then with CCCT plants using LFO. In the CPW analysis, no costs related to GHG emissions were included. Holyrood has an additional risk regarding the extent of life extension capital required to that this aging facility can reliably sustain operations until its targeted retirement dates in the early 2030's.

6.0 Interconnected Island Alternative - Phase 2

The next step in the electric power system planning process involves the development of optimized least cost generation expansions plans in *Strategist®* for the Interconnected island supply alternatives that have advanced through Phase 1 Screening, while adhering to the generation and transmission planning criteria and the resource development constraints. The expansion plan is characterized by continued generation operations at Holyrood until 2017 when the Lower Churchill Project Phase 1 is commissioned. This section provides the Interconnected Island generation expansion plan along with it's with accompanying transmission planning considerations, concluding with the *Strategist®* CPW value for this alternative.

6.1 Interconnected Island Generation Expansion Plan

The Interconnected Island alternative is an optimization of generation alternatives primarily driven by the Muskrat Falls hydroelectric generating facility and the Labrador-Island Transmission Link. As indicated in Section 4.2.13, Muskrat Falls will have an installed capacity of 824 MW, and will have an average annual production of 4.9 TWh. Production from Muskrat Falls will be transmitted to the island over the 900 MW Labrador–Island Transmission Link, which extends from the Muskrat Falls site to Soldiers Pond on the eastern Avalon Peninsula.

With the construction and commissioning of Muskrat Falls and the Labrador–Island Transmission Link, production at the Holyrood Plant will be displaced. By 2021, after Muskrat Falls and the transmission link have been successfully integrated into the Island Interconnected system, thermal production at the Holyrood Plant will cease. The generators at the Holyrood Plant will then operate only as synchronous condensers to provide reactive power for the HVdc converter station at Soldiers Pond and voltage support on the eastern Avalon Peninsula. Post 2021, there will be no generation at the Holyrood Plant under the Interconnected Island alternative.

The Interconnected Island alternative and the Muskrat Falls and the Labrador Island Transmission Link practically eliminates the dependence on fuel and therefore the effects and risks of fuel in the Isolated Island alternative. The exposure to GHG emissions and carbon cost is also removed. Muskrat Falls and the Labrador Island Transmission Link, however, are megaprojects and have large capital expenditures associated with them. In this regard, Nalcor has established a dedicated project team for Muskrat Falls and the transmission link, and has established a comprehensive project planning process for their development. Details on the processes, tools, and methodologies, as well as broader context on the projects themselves, are included in Volume 2, Muskrat Falls and Labrador Island Link Project Planning.

While the expansion plan is dominated by Muskrat Falls and the Labrador Island Transmission Link, the generation alternatives available from those not screened out in Section 4 are also available for inclusion in the expansion plan. These include:

1) Small hydroelectric developments, and more specifically, Portland Creek, Island Pond, and Round Pond,
2) Simple cycle combustion turbines (CTs),
3) Combined cycle combustion turbines (CCCTs).

It should be noted that generation additions after Muskrat Falls and the Labrador Island Transmission Link are driven by capacity shortfalls and not by energy shortfalls.

The *Strategist®* software was used to develop the least cost interconnected expansion plan. The system additions are listed in Table 26 and have been characterized as generation planning criteria-driven investments versus life extension and replacement capital.

Table 26: Interconnected Island - Installations, Life Extensions and Retirements (In-service capital costs; $millions nominal)

Year	Criteria Driven		Life Extension/ Replacement		Retirements
	Description	Cost	Description	Cost	Description
2014	50 MW CT	$75			
2017	Holyrood Unit 1 & 2 Synchronous Condensers 900 MW Labrador Interconnection Commencement of Supply from Muskrat Falls	$3 $2,553* PPA			
2021					Holyrood Unit 1 (161.5 MW) Holyrood Unit 2 (161.5 MW) Holyrood Unit 3 (142.5 MW)
2022					Hardwoods CT (50 MW) Corner Brook Pulp and Paper Co-Generation (PPA)
2024					Stephenville CT (50 MW)
2028					2 * 27 MW Wind farms (PPA)
2036	23 MW Portland Creek	$156			
2037	170 MW CCCT	$373			
2039					50 MW CT
2046	50 MW CT	$141			
2050	50 MW CT	$152			
2054	50 MW CT	$165			
2058	50 MW CT	$179			
2063	50 MW CT	$197			
2066	50 MW CT	$209			
2067					170 MW CCCT

* $2.553 billion includes total capital cost of $2.073 billion plus $480 million in allowance for funds used during construction (AFUDC)

Source: NLH, *2010 PLF Strategist Generation Expansion Plans*, 2011 (Exhibit 14)

For the purposes of balancing energy supply late in the study period, NLH has assumed that energy from Churchill Falls will be delivered to the island at historical power contract prices. Deliveries are forecasted to commence in 2057 and reach an annual delivery of approximately 500 GWh per year at the end of the study period in 2067. The impact of using market prices for these deliveries is addressed in Section 7.2.

The Interconnected Island alternative provides access to a large energy supply. The average annual production potential at Muskrat Falls, at 4.9 TWh, is greater than the approximately 2

TWh per year forecasted to be required on the island in 2017. For the purposes of this CPW analysis, NLH has assumed that no revenue benefits would be derived from that surplus energy. Notwithstanding, approximately 60 percent of the production from Muskrat Falls will be initially available for either short term sales into export market sales or for other interconnected requirements in the province, including demands in Labrador.

Muskrat Falls will benefit from the *Water Management Agreement*[54] in place between Nalcor and Churchill Falls (Labrador) Corporation. This agreement requires that the operation of Muskrat Falls be coordinated with that of Churchill Falls, and increases the ability of Muskrat Falls to schedule production to meet island needs than without a water management agreement. If the agreement were not in place, Muskrat Falls production would be limited to that available based on natural inflows and production at Churchill Falls.

Holyrood Operations under the Interconnected Island Alternative

Due to the age of the Holyrood plant, and experience with unplanned unit outages caused by equipment failure in recent years, NLH applied to the Board in the summer of 2009 for approval to begin Phase 1 of a condition assessment and life extension program for the plant. The Board granted partial approval to NLH to proceed and the initial work elements have now been completed with a report finalized in March of 2011.

The report, prepared by the engineering consulting firm AMEC, titled *Holyrood Condition Assessment and Life Extension Study 2010*[55] was filed with the Board on May 2nd, 2011. In summary, the condition assessment and life extension program for the Holyrood Plant was based on the following operational assumptions under an Interconnected Island supply future:

1. The Holyrood plant would be required to operate as a generating station until at least the end of 2016.

[54] Nalcor Energy and Churchill Falls (Labrador) Corporation, *Water Management Agreement*, 2009 (Exhibit 17)
[55] AMEC, *Holyrood Thermal Generating Station Condition Assessment & Life Extension Study*, 2011 (Exhibit 44)

2. The Holyrood plant would be maintained for standby power mode of operation from 2017 to 2020. To achieve this capability with a high degree of reliability, the power generation systems will be maintained as required.
3. The Holyrood plant would primarily be operated as a synchronous condensing station from 2017 on into the future.

The scope of the AMEC Phase 1 study was to determine the basic condition of the power plant, assess its useful life, and identify components, systems or facilities which require further attention. Phase 1 also assists NLH in selecting the sampling and testing methodologies to be used in performing more detailed investigation where recommended. Within a condition assessment and life extension program, the investigative work is used to determine whether the plant is a candidate for life extension and what recommended actions will achieve the extended life. The report prepared by AMEC under Phase 1 was used as a reference for planning Phase 2 of the condition assessment and life extension program. The Phase 2 study will enable NLH to identify equipment and systems that require immediate attention in order to operate the Holyrood plant as a generating facility safely and reliably up to 2016.

6.2 Interconnected Island Transmission

The Interconnected Island alternative results in the construction of a 900 MW HVdc transmission line from Labrador to the island and the cessation of production at the Holyrood Plant. With the existing 230 kV transmission system between Bay d'Espoir and the St. John's load center planned with the injection of 466 MW for the Holyrood Plant in mind, substantial reinforcements to the 230 kV transmission system in the eastern portion of the Island would be required following removal of the 466 MW from the Holyrood Plant if the HVdc converter station were to be located off the Avalon Peninsula. By locating the HVdc converter station at Soldiers Pond, a location between the Holyrood Plant and the St. John's load center where all critical 230 kV transmission lines on the Avalon Peninsula meet, NLH avoids significant construction of 230 kV ac transmission lines in the Interconnected Island alternative.

Transmission system analysis of the proposed Interconnected Island alternative has determined the system reinforcements required to meet the transmission planning criteria with the HVdc converter station located at Soldiers Pond. The line commutated converter technology requires a significant quantity of reactive power to support its operation – approximately 55 percent of its MW rating. In addition proper operation of the converter requires adequate system strength measured in terms of the system's equivalent short circuit ratio (ESCR) at the ac connection point for the converter. Analysis has indicated that conversion of the Holyrood generators to synchronous condensers assists in the supply of reactive power support and adequate ESCR levels. Stability analysis using *PSS®E* has determined that high inertia synchronous condensers and the 230 kV transmission line between Bay d'Espoir and Western Avalon are required to provide acceptable dynamic performance of the Interconnected Island alternative[56]. The additional system inertia provided by the high inertia synchronous condensers is required to maintain acceptable system frequency during system disturbances that result in temporary disruptions to the HVdc system. The 230 kV transmission line between Bay d'Espoir and Western Avalon ensures angular stability of the system for short circuits close to the Soldiers Pond converter station that will result in temporary commutation failure of the converter. Short circuit analysis using *PSS®E* has determined the impact on short circuit levels on the system due to the increase in number of synchronous machines (Soldiers Pond synchronous condensers) and reconfiguration in transmission system topology (Soldiers Pond Terminal Station and new 230 kV transmission line). The short circuit levels at a number of stations will increase to the point where existing circuit breaker interrupting rating will be exceeded. In the Interconnected Island alternative, one 230 kV circuit breaker at Bay d'Espoir, nine 230 kV circuit breakers at Holyrood, and four 66 kV circuit breakers at Hardwoods, will be replaced. The costs associated with these circuit breaker replacements are included in the capital cost estimate for the Labrador-Island Transmission Link. The costs associated with the new 230 kV transmission line between Bay d'Espoir and Western Avalon are common to both the Isolated Island and Interconnected Island alternatives. Therefore these costs are excluded

[56] NLH, HVdc System Integration Study, (Exhibit CE-3)

from the *Strategist®* analysis itself. However, such common costs are included in NLH's total revenue requirement calculations.

6.3 Interconnected Island CPW

The CPW for the Interconnected Island alternative, which brings together the Island and Labrador power grids, combined with Muskrat Falls hydroelectric power generation located on the Lower Churchill, has a CPW of $6,652 million (2010$). This CPW includes all of the costs associated with the Muskrat Falls generation plant and HVdc transmission interconnection between Labrador and the island, as well as all other operating and capital costs attributable to the Interconnected Island generation expansion plan as presented in Section 6.1. By breaking out the *Strategist®* CPW into its principal cost categories the shift in cost structure and corresponding risks can be observed. The CPW detail is provided below in Table 27 and Figure 28.

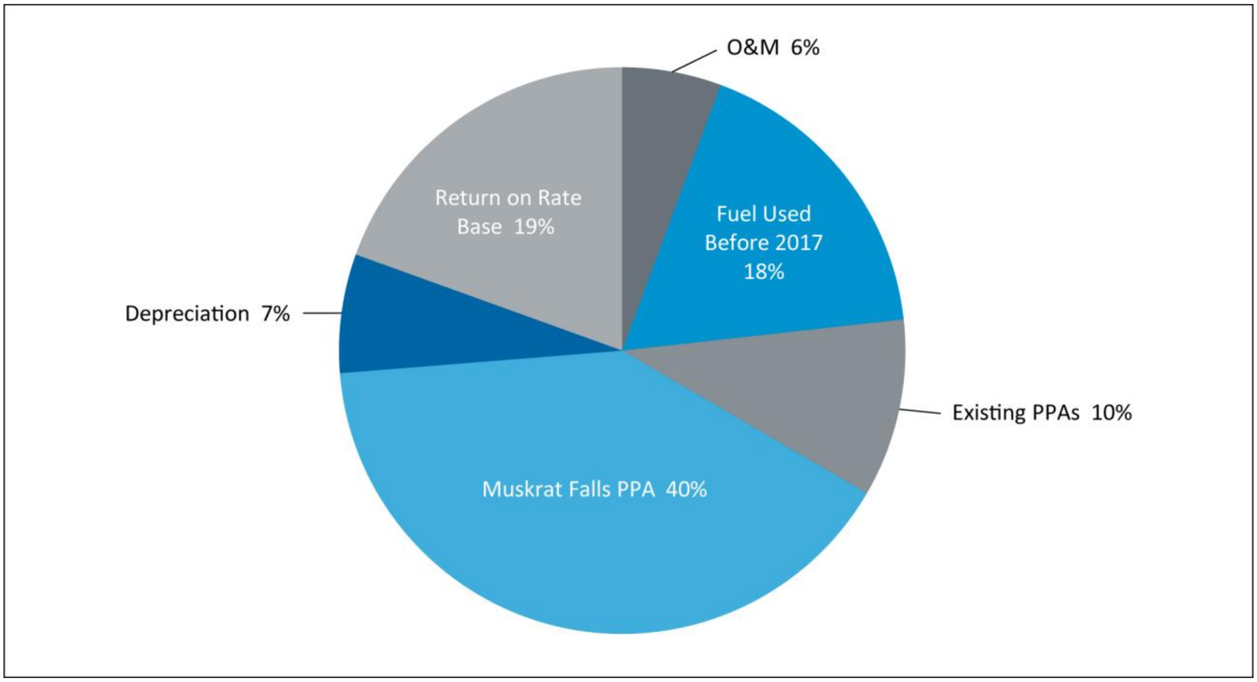
Table 27: Interconnected Island Alternative: Generation Expansion Plan CPW (2010$, millions)

	O&M	Fuel	Existing PPAs	Muskrat Falls PPA	Depreciation	Return on Rate Base	Total
Interconnected Island	$376	$1,170	$676	$2,682	$450	$1,297	$6,652
% of Total CPW	5.7%	17.6%	10.2%	40.3%	6.8%	19.5%	100.0%

Source: Nalcor response to MHI-Nalcor-1

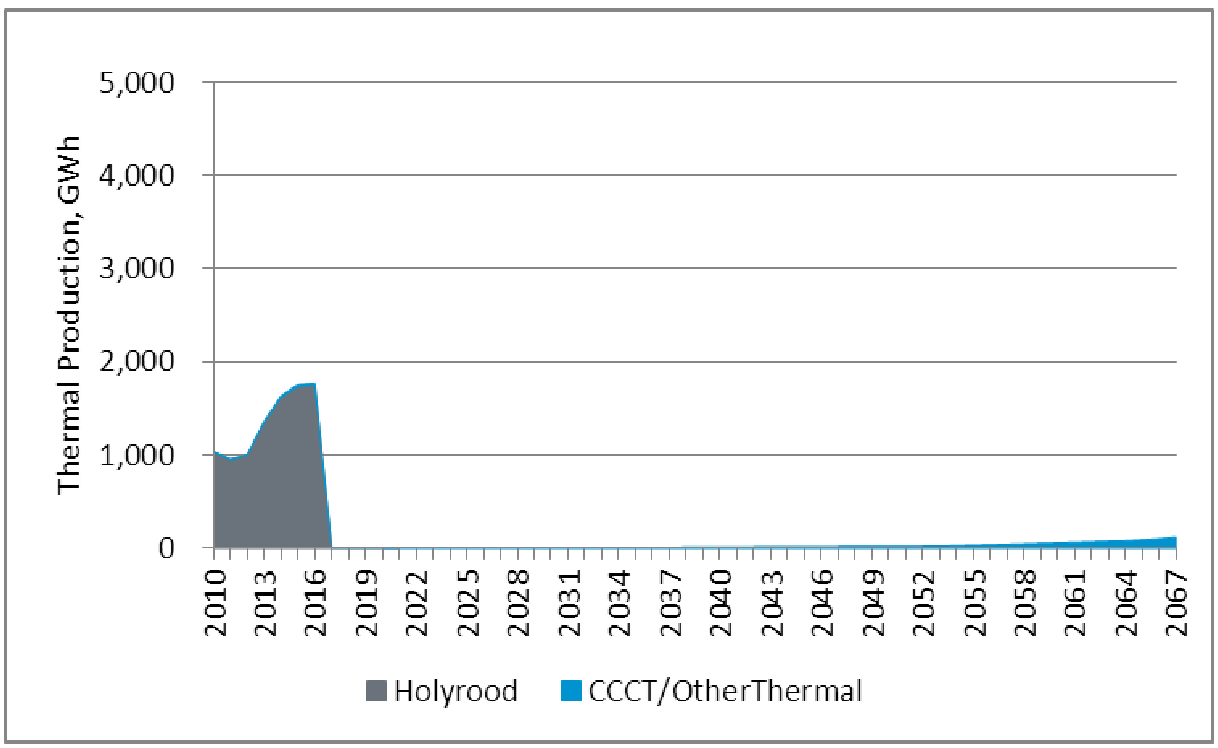
The dominance of fossil fuel in the incremental cost structure drops to under 20 percent with the Island Interconnected electricity supply future, and these fuel costs are predominately thermal fuel expenses incurred prior to the full commissioning of Muskrat Falls in 2017. Costs related to the purchase of power and energy from the Muskrat Falls facility, at stable and known prices; now replace the alternative dependence on fossil fuel. In addition, while this alternative will have a higher return on rate base requirement owing to interconnecting transmission infrastructure, the rate of return on rate base is generally stable and will result in declining annual costs once the asset is placed in service. Figure 29 below illustrates the impact of the closure of the Holyrood Plant on fuel requirements in the Interconnected Island expansion plan. As the reliance on thermal production essentially drops to immaterial quantities, so too does the exposure to future regulation of GHG.

Figure 28: Interconnected Island Alternative CPW Breakdown (2010$, millions and % of total)



Source: Nalcor response to MHI-Nalcor-1

Figure 29: Thermal Production Required – Interconnected Island Alternative



Source: Nalcor response to MHI-Nalcor-49.1

6.4 Summary

The preparation of a least cost generation and transmission plan for the Interconnected Island alternative in Phase 2 results in a CPW of $6,652 million ($2010, present value). A progressive dependence for the island portion of the province on thermal fuel is eliminated by 2017 and the Island Grid is interconnected to power generation supply on the Churchill River and to regional electricity markets outside the province. The major risks for this generation expansion alternative are construction project risks, with risk mitigation addressed in Volume 2.

7.0 Cumulative Present Worth Analysis

The purpose of this section is to compare the CPWs for the Isolated and Interconnected Island long-term generation expansion alternatives and to conclude on the economic preference for one alternative versus another. A number of sensitivity analyses are then presented to evaluate the impact of variation in key inputs to the *Strategist®* economic analysis on the CPW results.

7.1 Comparative CPWs

The CPW for the Isolated Island alternative, at $8,810 million, compared against the CPW for the Interconnected Island alternatives, at $6,652 million, yields an economic preference for the interconnected electricity supply alternative of $2,158 million (2010$). The change in cost structure, from a progressive dependence on international fossil fuels to one funding local power infrastructure, is achieved with the Interconnected Island alternative and at a lower long run cost for consumers. The comparative CPWs for the two alternatives are summarized in Table 28 below.

Table 28: Comparison of Generation Expansion Alternatives: CPW by Cost Component (Present Value 2010$, millions)

CPW Component	Isolated Island	Interconnected Island	Difference
Operating and Maintenance	$634	$376	($258)
Fossil Fuels	$6,048	$1,170	($4,878)
Existing Power Purchases	$743	$676	($67)
Muskrat Falls Power Purchases	NA	$2,682	$2,682
Depreciation	$553	$450	($103)
Return On Rate Base	$831	$1,297	$466
Total CPW	**$8,810**	**$6,652**	**($2,158)**

Source: Nalcor response to MHI-Nalcor-1

7.2 Sensitivity Analysis

The generation expansion CPW analysis for the island grid has numerous input and economic and financial levers. A sensitivity analysis, wherein the value for a key input variable is increased or decreased to determine its impact on a reference case result, provides useful information concerning the robustness of the analytical results and investment preferences arising therefrom. During the course of both the independent review undertaken by Navigant Consulting and the current Board's review of NLH's least cost analysis, a number of sensitivities have been requested and analysis prepared. The CPW summary for each sensitivity is provided in Table 29 below.

The sensitivity analyses undertaken have demonstrated that the CPW preference for the Interconnected Island alternative over the Isolated Island alternative is robust. Except for the break-even load sensitivity case, all sensitivities analyzed maintained a preference for the Interconnected Island alternative. Even where sensitivity approaches a point of indifference on a CPW basis, a preference for the Interconnected Island alternative may remain. For example, under a low world oil price scenario as developed by PIRA Energy[57], the CPWs for the alternatives are approaching breakeven, but that result does not necessarily diminish the more strategic value of developing indigenous renewable energy resources with known and stable costs. And while a future with low oil prices may be plausible under certain conditions, a future with higher-than-reference pricing may also be considered plausible. It is also noteworthy that using the May 2011 long-term reference oil price forecast from PIRA Energy[58] would increase the reference CPW preference for Interconnected Island alternative by 30 percent.

[57] NLH bases its low and high heavy and distillate fuel oil price forecasts for its thermal plants on oil market scenarios as developed by PIRA Energy. To illustrate the price ranges for these price scenarios, from Table 8 the average price for NLH's 0.7%s heavy fuel oil for the period 2010 to 2017, as of January 2010, is \$99 /BBL CDN. By contrast, the low price forecast for the same period is \$52 /BBL, while the high price forecast is \$156 /BBL.

[58] Nalcor response to MHI-Nalcor-126

Table 29: Summary of CPW Sensitivity Analysis with Respect to Reference Case and Preference (Present Value 2010$, millions)

	Isolated Island	Interconnected Island	Preference for Interconnected island
Reference Case	**$8,810**	**$6,652**	**($2,158)**
PIRA High World Oil Forecast	$12,822	$7,348	($5,474)
PIRA Low World Oil Forecast	$6,221	$6,100	($120)
PIRA May 2011 Update For Reference Oil Price Forecast	$9,695	$6,889	($2,806)
Moderate Conservation (375 GWh by 2031)	$8,363	$6,652	($1,711)
Aggressive Conservation (750 GWh by 2031)	$7,935	$6,652	($1,283)
Loss of 880 GWH 2013 Forward	$6,625	$6,625	($0)
Low Load Growth (50% of 2010 PLF post Vale)	$7,380	$6,628	($752)
200 MW Additional Wind (100 MW in 2025 and 100 MW in 2035)	$8,369	$6,652	($1,717)
MF and LIL Capital Cost +20% & Fuel Costs Reduced by 20%	$7,600	$7,217	($383)
MF and LIL Capital Cost +25%	$8,810	$7,627	($1,183)
MF and LIL Capital Cost +50%	$8,810	$8,616	($194)
Federal Loan Guarantee	$8,810	$6,052	($2,758)
Holyrood to 2041, then CF at Market Price	$7,935*	$6,652	($1,283)
Carbon Pricing on Fossil Fuel	$9,324	$6,669	($2,655)
CF Energy Post 2067 at Market Rates Instead of Cost	$8810	6664	($2146)

- The deferred CF alternative is not an Isolated Island alternative, however it has been included in this column for comparative purposes against the isolated Island reference case
- PIRA High and Low World Oil Prices forecasts as of March 2010

Sources: (1) NLH, *2010 Expansion Plan Analysis*, 2010 (Exhibit 43)
(2) Nalcor response to PUB-Nalcor-54
(3) Nalcor response to PUB-Nalcor-118
(4) Nalcor response to MHI-Nalcor-3

Important sensitivities concern the impact on the CPW analysis from having a much more ambitious conservation effort as well as the use of additional wind power as a longer term supply alternative in the Isolated Island alternative. In either case the analysis does not support a conclusion that conservation and wind provide a long-term lower cost electricity supply future for consumers. As noted in Section 4.2.8, the important constraint to appreciate for the wind resource is that the island power system has firm operational restrictions on the amount of wind power that can be installed.

The ability to capture the opportunity to displace existing thermal operations at the Holyrood Plant is an important component of the CPW analysis. This contributes to a result that even with a low load growth future, at 50 percent of the utility reference projection, there continues to be a CPW preference for the Interconnected Island alternative. Conversely, load growth could be somewhat stronger than projected in the 2010 PLF reference analysis. NLH has not yet made explicit provision for the possibility that an Interconnected Island alternative may have moderately higher long-term energy requirements owing to a maximum conversion of housing stock to electric space heating and price elasticity impacts encouraged by stable electricity rates. These considerations will be covered during its DG3 analysis.

By lowering interest expense during both the construction period and debt terms for Muskrat Falls and the Labrador Island Link, the Federal Loan Guarantee confers benefits that increase the CPW preference for the Interconnected Island alternative by $600 million. This support from the federal Government of Canada for a renewable electricity future increases the economic preference for the Interconnected Island alternative by over 25%

The capital cost increase of 25 percent for the Lower Churchill Project demonstrates the importance of a cost overrun risk to the overall CPW analysis and is why LCP has devoted such effort to risk assessment and mitigation[59]. Even with a sensitivity analysis where capital costs for both Muskrat Falls and the Labrador Island Transmission Link are increased by 50%, the CPW preference for Island Interconnected remains positive.

[59] Volume 2, Section 4.7

The generation expansion alternative of continuing to maintain operations on the Isolated island grid until the expiry of the Churchill Falls contract was also analysed within *Strategist®*. To allow for additional life extension capital for Holyrood to enable reliable operations to 2041, a total additional expenditure provision of $200 million in-service for each of the three thermal units was included in isolated costs. The Labrador Island Link capital was escalated for an in-service of 2041 and the pricing assumption for Churchill Falls energy was the projected regional New York market price. The CPW preference of $1.3 billion continued to prevail for the Interconnected Island alternative as compared to a deferred Interconnection in 2041 with access to Churchill Falls thereafter for an energy source.

A carbon pricing sensitivity reflects the environmental risk associated with a thermal future[60]. With a seemingly increasing likelihood of a future regulatory carbon pricing regime, the impact on electricity consumers in an Isolated Island alternative would be higher production costs where oil is used in thermal power generation.

NLH has also completed an analysis of the cost impact of importing production from Churchill Falls at market rates in the period 2057 to 2067 in the Interconnected Island reference case rather than at historical power contract prices. With an adjustment to projected market rates, this would increase the CPW reference value by $12 million to $6,664 million from $6,652 million.

For the sensitivity results, there are some combinations of individual case results that are valid, and some combinations that not valid to bundle together. For example, a valid combination of sensitivity results would be Carbon Pricing on Fossil Fuel and the Federal Loan Guarantee. However, combining the Conservation sensitivities with the Additional Wind sensitivity would not be valid. This is because in the Isolated Island alternative it is the presence of additional load supplied by thermal production that allows the wind to operate in the first instance without increasing the probability of spill at NLH's existing reservoirs.

[60] Carbon pricing as per Navigant Consulting Ltd.'s use of projections developed by the US Department of Energy based on an analysis of Waxman-Markey legislation. Prices equal $30 nominal per tonne in 2020.

7.3 Summary

The comparison of the CPW for an Isolated Island electricity supply future against an Interconnected Island alternative which includes the development of Muskrat Falls with a transmission interconnection between the island and Labrador, results in an economic preference for the Interconnected Island alternative of $2.2 billion ($2010, present value). Various sensitivities analyses of variation in key inputs impacting the CPW analysis, point to this economic result being robust. The availability of a federal loan guarantee increases the economic preference for the Interconnected Island by over 25%.

8.0 Transmission Reliability

Having identified the least cost generation expansion plans for both the Isolated Island alternative and the Interconnected Island alternative, and completed the CPW Analysis to determine the least cost generation expansion alternative for the island system, an analysis of the potential impact the preferred 900 MW HVdc interconnection between Labrador and the island will have on transmission system reliability is warranted. This section assess transmission system reliability for the Isolated Island alternative, the Interconnected Island alternative and the Interconnected Island alternative with the Maritime Link in terms of level of exposure, measured as availability of energy supply, and level of unsupplied energy for a significant transmission system outage.

8.1 Reliability Assessment

System reliability is addressed in detail in *Technical Note: Labrador–Island HVdc Link and Island Interconnected System Reliability*[61]. The following paragraphs provide a synopsis of this document.

As explained in Section 3 of this report and in NLH's *Transmission Planning Manual*[62] and Island Transmission System Outlook Report[63] both the Isolated Island and Interconnection Island alternatives were tested for compliance against NLH's accepted generation planning and transmission planning criteria. These planning criteria adhere to industry accepted practice and compliance with them assures a level of reliability that is at least consistent with historical experience.

Within any electrical system there are always low probability, high impact events that could result in violation of criteria and the subsequent inability to fully supply customer load. Because of the low probability of occurrence, and the often high cost of mitigating the occurrence, utilities accept the risk and develop response plans to react should the low

[61] NLH, *Technical Note: Labrador – Island HVdc Link and Island Interconnected System Reliability,* 2011 (Exhibit 106)
[62] NLH, *Transmission Planning Manual, Rev 2*, 2009. (Exhibit 105)
[63] NLH, *Island Transmission System Outlook*, 2010 (Exhibit 24)

probability event occur. In the NLH system there are low probability events in the existing system, in the future Isolated Island Expansion Plan, and in the Interconnected Island Expansion Plan that, should they occur, fall into this category. Analysis has been completed to assess the current day level of risk and exposure in comparison to the risks and exposures associated with future Island Isolated and Island Interconnected expansion plans as a basis to determine whether further mitigation is required.

For the current Island system, the loss of the 230 kV TL202/206 transmission corridor between Bay d'Espoir and Sunnyside is an accepted risk that could, if it happened at certain times of the year, result in an inability to supply full load. The *Technical Note: Labrador – Island HVdc Link and Island Interconnected System Reliability*[64] indicates that for the system in 2012, the probability of this loss occurring at a time that will result in load curtailment is approximately 2 percent. The expected level of load curtailment during the event would be between 0 and 80,000 MWh depending on what time of year the outage occurs (based on assumptions in the Technical Note). This is representative of the level of risk and exposure that has been present on the Island system for many years. The Technical Note also indicates that for the Isolated Island future, both the probability of occurrence and the maximum exposure associated with this event improve, particularly as more generating capacity is added to the Avalon Peninsula (CTs and CCCTs) and the 230 kV transmission line between Bay d'Espoir and Western Avalon is constructed.

The addition of a 900 MW HVdc transmission line between Muskrat Falls in Labrador and Soldiers Pond on the Island portion of the province has raised questions regarding the impact that such a significant change will have on the reliability of the Interconnected Island System. The Technical Note also presents a detailed assessment of the reliability implications for the link and determines that a bipole transmission failure resulting in the loss of 900 MW of supply results in risk and exposure numbers at least comparable to those for the TL 202/206 loss in the existing system. While the probability of an occurrence resulting in curtailment of customer load is lower (0.15- 0.65 percent) when compared to 2 percent in

[64] NLH, *Technical Note: Labrador – Island HVdc Link and Island Interconnected System Reliability*, 2011 (Exhibit 106)

the current case, the level of load curtailment could be between 0 and 94,000 MWh by 2036 and declining thereafter.

The Technical Note also discusses the proposed Maritime Link between the Island of Newfoundland and Nova Scotia and the effect this addition would have on system reliability. The analysis demonstrates that the Maritime Link improves the Island Interconnected System reliability. For the case of the loss of the 900 MW supply from Labrador, the probability that this event would result in curtailment of load is reduced to less than 0.1 percent, and the level of curtailment to between 0 and 16,000 MWh.

Table 30 summarizes the exposure levels and unsupplied energy for the Isolated Island, Interconnected and Interconnected with Maritime Link Scenarios.

The probability of a transmission line failure that results in the inability to supply all customer load is dependent, in part, on the mechanical design of the transmission line itself. Transmission line design methods today consider the meteorological loadings (wind and ice) along the transmission line route, the return periods of weather events[65], the transmission line materials (wood, steel), and utilize reliability based methods to provide a coordinated transmission line design with known failure rates and modes for expected meteorological conditions. Based upon NLH's experience with weather related damage to existing 230 kV transmission lines on the Avalon Peninsula, analysis was conducted to determine the return periods of the various storms. The results of the analysis, *Reliability Study of Transmission Lines on the Avalon and Connaigre Peninsulas*[66] filed as Exhibit 85 provides significant detail on the subject. Basic outcomes from this study include the identification of the 1:50 year return period load levels, the design return periods for existing 230 kV transmission lines, and NLH's decision to use the 1:50 year return period loads for all new 230 kV transmission line construction on the Avalon Peninsula.

---

[65] At a high level, a 1:50 year return period for a weather event means that one can expect the design load to occur at least once in 50 years. The probability of the 1:50 year storm occurring in any one year is 2 percent.

[66] NLH, *Reliability Study of Transmission Lines on the Avalon and Connaigre Peninsulas*, 1996 (Exhibit 85)

Table 30: Level of Exposure and Unsupplied Energy

Year	Load Forecast		Island Standby Generation MW	Level of Exposure Load Exceeds Generation		Availability %	Unsupplied Energy Worst 2 week Window	
	MW	GWh		Annual Hours	Annual %		MWh	% of Annual
Isolated Island – TL202/206 Outage								
2012	1,571	7,850	635.1	4,318	49.29	98.02	79,969	1.02
2017	1,704	8,666	965.2[1]	865	9.87	99.605	13,435	0.16
2021	1,757	8,967	965.2	1,206	13.67	99.449	19,838	0.22
2022	1,776	9,065	1,085.2[2]	200	2.28	99.909	2,622	0.029
2027	1,856	9,464	1,185.2[3]	50	0.57	99.977	553	0.006
2032	1,934	9,860	1,235.2[4]	0	0	100.0	0	0
2037	2,006	10,228	1,277.7[5]	58	0.66	99.974	649	0.006
Island Interconnected – Bipole Outage								
2017	1,704	8,666	1,468.5	637	7.27	99.854	14,384	0.16
2022	1,776	9,065	1,418.5[6]	1,431	16.34	99.673	37,019	0.40
2027	1,856	9,464	1,368.5[7]	2,279	26.02	99.480	66,883	0.70
2032	1,934	9,860	1,368.5	2,691	30.72	99.386	85,888	0.87
2036	1,992	10,157	1,391.5[8]	2,831	32.32	99.354	93,744	0.92
2037	2,006	10,228	1,561.5[9]	1,683	19.21	99.616	50,900	0.498
Island Interconnected – Bipole Outage – Maritime Link In Service								
2017	1,704	8,666	1,768.5	0	0	100.0	0	0
2022	1,776	9,065	1,718.5[6]	19	0.22	99.996	389	0.004
2027	1,856	9,464	1,668.5[7]	281	3.20	99.936	6,019	0.064
2032	1,934	9,860	1,668.5	626	7.14	99.986	15,765	0.160
2037	2,006	10,228	1,861.5[8,9]	118	1.34	99.973	2,342	0.022

Notes
1: 230 kV transmission line Bay d'Espoir to Western Avalon is built prior to 2017 increasing transfer to east coast for loss of TL202 and TL206.
2: 170 MW CCCT in 2022 at Holyrood and Hardwoods 50 MW CT retired in 2022
3: 50 MW CT in 2024 and 50 MW CT in 2027 both assumed on Avalon Peninsula
4: 50 MW CT in 2030
5: Holyrood units replaced with 170 MW CCCT (1&2 in 2033 + 3 in 2036)
6: Hardwoods 50 MW CT retired in 2022
7: Stephenville 50 MW CT retired in 2024
8: 23 MW Portland Creek in 2036
9: 170 MW CCCT in 2037

Source: NLH, *Technical Note: Labrador – Island HVdc Link and Island Interconnected System Reliability*, 2011 (Exhibit 106)

Given reliability-based designs ranging from 1:10 year return period for existing wood pole lines, to 1:25 year return period for rebuilt steel lines on the Avalon and a 1:50 year return period for the proposed Bay d'Espoir to Western Avalon 230 kV transmission line, NLH adopted the 1:50 year return period as the basis of design for the HVdc transmission line between Labrador and the island portion of the province.

In the context of the analysis completed in the Technical Note on reliability, increasing the return period of the HVdc transmission line design from 1:50 years to, say 1:150 years, would reduce the probability of the occurrence of the event resulting in inability to supply all customer load. For the Interconnected Island alternative with a 1:50 year return period design for the HVdc line the probability of occurrence is 0.15- 0.65 percent (availability 99.35 – 99.85 percent). If the HVdc line return period were increased to 1:150 years, the probability of occurrence of the event resulting in inability to supply all customer load would be 0.04 – 0.22 percent (availability 99.78 – 99.95 percent). However, the level of load curtailment (i.e. quantity of unsupplied energy during the two-week anticipated repair interval after an event), should the event occur, would not change with the change in design return period. In other words, increasing the return period of the line design reduces the probability of a failure for a given storm, but when the line failure happens the same number of customers will be without electricity. In essence, increasing the return period of the line design alone solves only one aspect of the exposure to Island customers for loss of the Labrador–Island HVdc Link.

A comparison of the exposure levels and unsupplied energy between the Interconnected Island alternative and the Interconnected island with Maritime Link alternative, as shown in Table 30, highlights the reductions in unsupplied energy that can be attributed to the additional 300 MW of capacity available via the Maritime Link[67] following the outage to the Labrador-Island HVdc Link. In both the Interconnected Island and the Interconnected Island with Maritime Link alternatives, the Labrador – Island HVdc Link is built to a 1:50 year return period. The availability of a 300 MW import to the island via the Maritime Link reduces the level of curtailment from 0 – 94,000 MWh to 0 – 16,000 MWh. In other words, the fact that the Maritime Link provides an alternate path for capacity and energy following and outage to the Labrador–Island HVdc Link, the probability of unsupplied energy is reduced and the expected level of unsupplied energy is reduced to less than 20 percent of what would

[67] Although the Maritime Link is nominally rated at 500 MW, import capacity from New Brunswick into Nova Scotia is currently limited to 300 MW.

otherwise be expected without the Maritime Link. This translates to fewer customers being without electricity for a shorter period of time during the outage.

The analysis provided in the Technical Note demonstrates the impact of adding 50 MW CTs in the Interconnected Island alternative has on the exposure levels (the probability of an outage) and unsupplied energy (the amount of energy that will not be supplied as a result of the outage). This section of the Technical Note on reliability provides a useful tool in assessing system additions to meet a predefined target. For example, if one were to assume a desired reliability level based upon an availability value of 99.5 percent and an unsupplied energy not to exceed 35,000 MWh for a two week outage window, one can determine the number and timing of 50 MW CTs required to maintain the criteria. As an example (not meant to be taken as a recommendation) the number and timing of 50 MW CTs could be as per Table 6 in Exhibit 106:

- 2022: 1 x 50 MW CT for availability of 99.76 percent and unsupplied energy of 27,000 MWh;
- 2027: 2 x 50 MW CT for availability of 99.82 percent and unsupplied energy of 31,000 MWh;
- 2032: availability of 99.71 percent and unsupplied energy of 35,000 MWh – new CT in 2033;

The analysis indicates that reduction in unsupplied energy due to loss of the HVdc transmission line in the Interconnected Island alternative is better managed through the addition of 50 MW CTs as required to meet the curtailment target, rather than through investments in increasing the HVdc line design return period beyond the existing 1:50 years carried in the basis of design.

Continued operation of the HVdc converter station at Soldiers Pond requires that the underlying 230 kV ac transmission system on the island remain relatively intact. Analysis has been conducted using *PSS®E* to ensure successful operation following loss of a single 230 kV transmission line. Given that the 230 kV transmission system has been designed with equivalent return periods on the order of 1:10 years for wood pole lines, 1:25 years for rebuilt steel lines and 1:50 years for new 230 kV transmission lines, building the HVdc line to a design load beyond 1:50 years is viewed as ineffective. Assuming a major storm with a return period in excess of 1:50 years, one can expect damage to most, if not all, 230 kV transmission lines. Building the HVdc line to withstand the 1:100 year storm, for example, would mean that the only transmission line remaining in service would be the HVdc line. Without the support of the underlying 230 kV ac transmission system the HVdc converter station would not be able to function, nor deliver energy to customers.

Based upon the reliability analysis, NLH sees no compelling reason to move away from a 1:50 year return period for the HVdc line design. In the absence of the Maritime Link, the addition of 50 MW CTs is the most effective means to limit exposure and unsupplied energy/load curtailment for the low probability, high risk event. With alignment on the limit of exposure, 50 MW CT additions can be added to the Island Interconnected system expansion plan to satisfy the criteria.

8.2 Summary

In conclusion, the reliability analysis demonstrates that the Interconnected Island alternative with the Labrador–Island HVdc Link designed for a 1:50 year return period will have a reliability level similar to that of the existing Isolated Island system on measures of probability of exposure and unsupplied energy during the outage. Further, the addition of the Maritime Link or 50 MW CTs to the Interconnected Island alternative are effective in reducing both the probability of exposure to an outage and the level of unsupplied energy during the outage.

Based upon the results of the transmission reliability analysis Nalcor is recommending that the Labrador–Island HVdc Link overhead line design be based on a 1:50 year return period. Given that this level of line design provides for an Interconnected Island alternative having a probability of exposure to an outage and a level of unsupplied energy during an outage similar to that of the Isolated Island system today, Nalcor sees no justification in increased capital expenditures on addition combustion turbines and is therefore recommending no additional CTs at this time.

9.0 NLH's Regulated Revenue Requirements and Overall Wholesale Rate Analysis[68]

The purpose of this section is provide an overview of how NLH prepares a long-term forecast for its annual regulated revenue requirements and how these estimates are used to project the unit cost trends for its overall wholesale rate for consumers on the island. In addition to NLH wholesale rates, which include the cost associated with generation and transmission, retail customers' rates include the cost of distribution infrastructure. In Newfoundland and Labrador, generation and transmission are generally provided by NLH, and distribution in the main population centers on the island provided by NF Power.

The process for establishing wholesale rates is discussed below in section 9.1 and retail rates are discussed in section 9.2.

9.1 Wholesale Rates

In order to forecast the annual financial costs for utility operations, and for a longer term electricity rate trend analysis, NLH undertakes an analysis of what its financial costs are for each and every year of the analysis period. This annual revenue requirement[69] can be summarized as the sum of the following general cost categories:

- Operating and maintenance expenses,
- Fossil fuel costs,
- Purchase power expenses from third or related parties,
- Annual capital charges, comprised of:
  - Depreciation,
  - Return on Rate Base, comprised of
    - Interest expenses, and

[68] NLH "overall wholesale rate analysis" is the total annual revenue requirement for the Island grid which would be almost 100% recovered from all of its customers on the Island grid.

[69] While the majority of NLH's costs are related to the Island power grid, it also incurs costs for its customers served from the Labrador power grid and from isolated diesel systems. Regulated costs incurred to serve Labrador grid and diesel system customers have been identified and excluded from this revenue requirement analysis.

    - Return on equity

- All other miscellaneous net cost items.

NLH's total revenue requirement in any given year in the planning period entails building up the costs for existing operating expenses and capital assets, with the incremental operating expenses and capital charges for a future long-term generation expansion plan. This is accomplished with the Revenue Requirement Model (RRM). The output of the RRM is an annual revenue requirement due from customers where prices are taken to be set such that revenues are perfectly matched to costs.

As applicable, the RRM uses the same corporate data as those used by *Strategist®* for production costing (e.g. load forecast, fuel prices, capital, cost of capital, escalation) in the determination of customer revenue requirement. This dual input process across two separate modeling environments provides an inherent check on the integrity of the *Strategist®* results.

To develop the annual revenue requirements the RRM draws together a wide range of financial data such as:

- Net book value by class for existing assets,
- Depreciation schedules for existing assets,
- Operating budgets for existing operations,
- Forecasts for sustaining capital from 5 and 20 year capital plans,
- Various rate base items such as deferred charges, inventories, and exchange losses,
- Existing debt, cost and term,
- Cost of new debt,
- Cost of equity,
- Budgeted revenues.

The inputs from *Strategist®* to RRM will be unique to each alternative generation expansion plan under study and analysis. The general categorization of *Strategist®* input costs to RRM are:

- In-Service capital costs for new generation plant, whether required to maintain appropriate generation planning criteria or replacement capital for obsolete plant,
- Operating costs associated with all new generation plant,
- Energy production by type (thermal, hydroelectric, wind), and
- Purchased energy and associated costs.

For regulated utilities, return on rate base includes a profit component for shareholders (return on equity) and a cost component for lenders (cost of debt). The recovery of these costs in customer rates enables the utility to finance assets used in the provision of electrical service. For each new generation plant identified by *Strategist®*, the RRM will finance the asset, place it into rate base, and set up a depreciation charge applicable for that class of assets. The return on rate base is calculated on total rate base for the company. While the cost of debt and equity capital are used in a consistent manner with *Strategist®*, the RRM has additional analysis detail on an annual basis for new debt issues (short or long-term), targeted capital structure, dividend policies, and weighted cost of capital.

There are key regulated capital parameters that are brought together to enable the calculation for the return on rate base:

- Debt-equity ratio: the capital structure for the company establishes the appropriate levels of debt and equity capitalization. Capital structure is normally approved by the regulator. The target debt ratio for NLH revenue requirement purposes has been set at 75 percent consistent with its current targets. The target equity ratio has been set at 25 percent.
- Debt: The cost of debt is a function of both the embedded cost of existing debt and the cost of projected new debt. The historical or embedded cost of debt for NLH is approximately 8.8 percent. Going forward, the cost of debt will take into account new debt. Projections for the cost of new NLH debt are tied to forecasts prepared by

the Conference Board of Canada. The forecasted long-term average cost of new NLH debt is 7.3 percent.

Equity: Going forward, Government directive is that the return on equity for NLH will be set on a consistent basis with Newfoundland Power. The forecast longer term average return on equity for regulated utilities is expected to be in the range of 9 percent to 10 percent. The return on equity will be no more, or no less, than a regulated industry standard.

Weighted Average Cost of Capital: Combining capital structure weighting with is cost by capital component results in a weighted cost of capital of 8 percent, which is also used consistently in *Strategist®* and taken as the discount rate for analytical purposes.

Thus the total revenue requirement for any given year is the sum of that year's operating costs, power purchases, fuel expenses, depreciation, and return on rate base. Combining the total annual revenue requirement due from customers, with total wholesale energy to be delivered as per the 2010 PLF, provides a projection of the overall wholesale rate trends for the electricity supply futures under analysis. These trends are illustrated in Table 31.

Table 31: Summary of Annual Revenue Requirement and Overall Wholesale Unit Cost Rate Trends for Isolated Island and Interconnected Island Electricity Supply Alternatives

	Isolated Island	Interconnected Island	Total Energy Delivered[70]	Unit Cost Rate Trend for Isolated Island	Unit Cost Rate Trend for Interconnected Island
	$ Millions, current		GWh	$ /MWh	
2010	$377.6	$377.6	6,044.8	$62	$62
2020	$804.1	$810.7	7,353.1	$109	$110
2030	$1,144.9	$923.8	8,168.9	$140	$113
2040	$1,803.9	$1,1134.6	8,873.9	$203	$128
2050	$2,443.5	$1,401.3	9,472.9	$258	$148

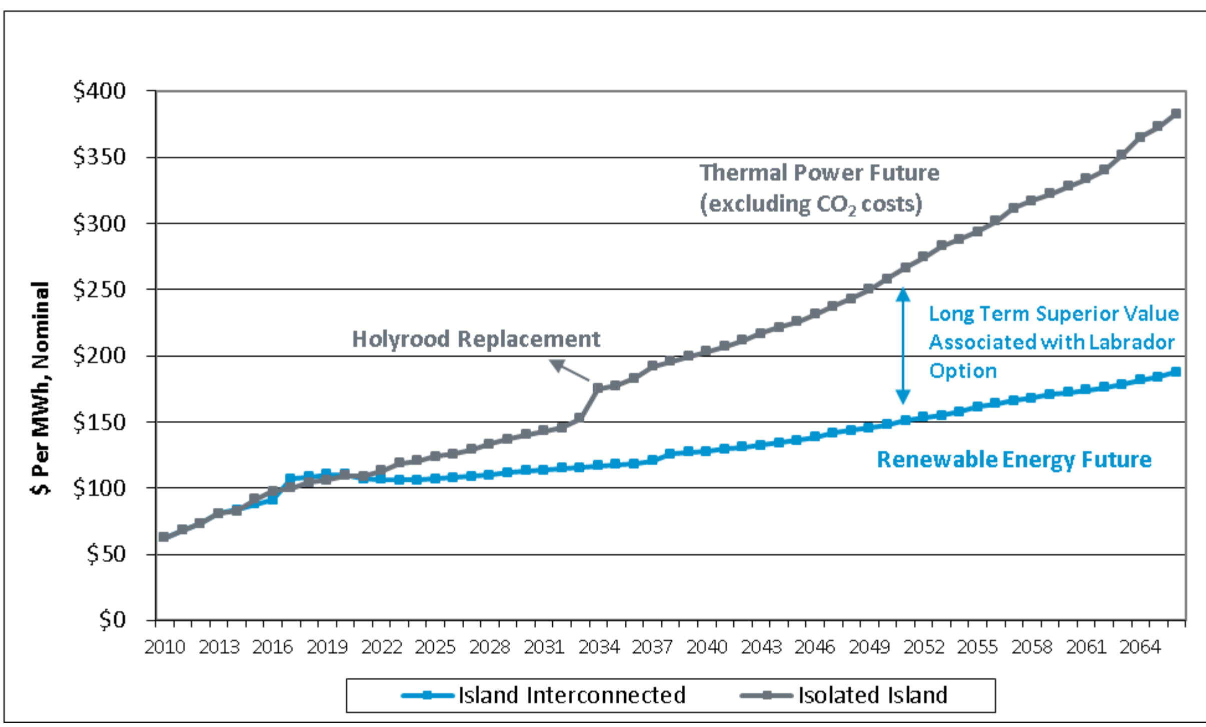
[70] Energy delivered by NLH at the transmission level represents NLH's wholesale delivery requirement for the Island grid. Starting in 2014, it is derived by subtracting customer-based generation and transmission losses from Total Island Load as per *2010 Planning Load Forecast (PLF) for the Island Interconnected System* (Exhibit 1). See accompanying notes to Nalcor response to PUB-Nalcor-5.

	Isolated Island	Interconnected Island	Total Energy Delivered[70]	Unit Cost Rate Trend for Isolated Island	Unit Cost Rate Trend for Interconnected Island
	$ Millions, current		GWh	$ /MWh	
2060	$3,280.3	$1,724.1	10,003.9	$328	$172

Source: Nalcor response to PUB-Nalcor-5

Figure 30 shows the overall wholesale unit cost rate trends for the alternative electricity futures, highlighting a directional change in cost structure for electricity supply to the island. For the period after 2017, the average annual growth in NLH unit costs is forecast at 2.8 percent for Isolated Island alternative and 1.1 percent for Interconnected Island. Because wholesale electricity costs comprise approximately two-thirds of retail electricity prices on the island, these growth rates will be correspondingly lower at consumer level. The integration of the Muskrat Falls hydroelectric plant and the Labrador Island Link into NLH's rate base will fundamentally change the cost structure for the island's electricity supply. As the overall wholesale prices are projected to increase well below the general rate of inflation, the price is declining in inflation adjusted terms across the planning period. Over time this means that electricity costs less in relative terms, thereby providing increasing value to consumers.

Figure 30: Newfoundland and Labrador Hydro: Island Regulated Revenue Requirements



Source: Nalcor response to PUB-Nalcor-5

9.2 Retail Rates

NLH has also provided initial estimates for the retail consumer rate impacts arising from the alternative generation expansion plans for the Island. Table 32 provides the impact on the average consumer rate for the Island grid resulting from the transition of wholesale costs through to retail[71]. These projected rate impacts are attributable only to the alternative electricity supply futures as analyzed through the preceding revenue requirement analysis.

Table 32: Projected Impact on Average Consumer Rate for the Island Grid

	Isolated Island Alternative ($/MWh)				Interconnected Island Alternative ($/MWh)			
	Overall NLH Wholesale Rate	Utility Wholesale Rate	Utility Retail Rate	Cumulative Retail Rate Increase	Overall NLH Wholesale Rate	Utility Wholesale Rate	Utility Retail Rate	Cumulative Retail Rate Increase
2011	$68	$64	$112	-	$68	$64	$112	-
2012	$73	$71	$120	7%	$73	$71	$120	7%
2013	$81	$83	$133	19%	$81	$83	$133	19%
2014	$83	$85	$136	21%	$84	$86	$137	22%
2015	$92	$95	$146	30%	$88	$92	$143	27%
2016	$97	$103	$154	37%	$91	$96	$147	31%
2017	$100	$106	$158	41%	$107	$113	$164	47%
2018	$104	$110	$161	44%	$108	$115	$166	48%
2019	$106	$112	$164	46%	$110	$118	$169	51%
2020	$109	$116	$168	49%	$110	$118	$170	51%
2030	$140	$149	$198	77%	$113	$123	$174	55%
2040	$203	$213	$252	125%	$128	$138	$189	68%

Source: Nalcor response to PUB-Nalcor-5 and accompanying notes.

The favorable change in cost structure associated with the Interconnected Island alternative translates directly through to the average retail rate for all domestic customers on the Island grid. Under the Isolated Island alternative, the average domestic rate is projected to be about 37% higher in 2016 than in 2011. As the respective cost structures for the future supply alternatives begin their diverging trends beginning around 2020, the value of an

[71] NLH has not factored in periodic rate increases attributable to the retail distribution utility. In addition, while these rate estimates were prepared at DG2 before the subsequent retail tax change announced by the Provincial Government, the cumulative percentage change for retail rates would not change.

Interconnected Island alternative begins to accumulate. By 2040, the cumulative rate increase for Island domestic consumers attributable to the Interconnected Island alternative is projected at 68%, in contrast to a cumulative rate increase of 125% for the Isolated Island.

9.3 Summary

The preparation of NLH's annual revenue requirement includes all operating and annualized capital costs associated with each respective generation planning alternative, and in addition, all common operating and capital related costs from NLH's existing operations not directly included in the *Strategist®* analysis. The overall wholesale rate for NLH is derived by dividing its annual wholesale cost by its annual wholesale energy deliveries. The trend in NLH wholesale unit costs is largely the same until 2017 regardless of long-term electricity supply alternative. Beyond 2020, the cost trends for Isolated and Interconnected Island generation expansion alternatives begin to diverge, reflecting the change in NLH cost structure under each respective case. Unit cost trends for the Isolated Island alternative increase at an annual rate of change that exceeds the general inflation rate. By contrast, the Interconnected Island wholesale rate trend is stable with an annual percentage change that tracks below the general rate of inflation, thus offering increasing value to consumers over time.

10.0 Conclusion

To assist the Board in its review of the Lower Churchill Project as requested by the Government of Newfoundland and Labrador, Nalcor has reviewed and presented in detail the system planning processes used to identify the long term, least cost solution for the continued supply of reliable power and energy for the island. The review began with an overview of the load forecasting responsibility undertaken by NLH. Generation and transmission planning criteria were then presented and the capabilities of the existing island grid were presented. Grid capabilities were then assessed against the load forecast using the established planning criteria to determine whether or not a need existed for power system expansion. Following the identification of capacity and firm energy deficits commencing in 2015 and 2021 respectively, a two phase screening process was introduced. Phase 1 screening identified the supply options considered by NLH to be viable for further analysis in the system planning modeling environment of *Strategist®*. Phase 2 provided screening and analysis for two long term development options for the supply of power and energy to the Island, namely, the Isolated Island alternative and the Interconnected Island alternative. Optimized generation expansion plans were prepared within *Strategist®* with the respective least cost plans for each alternative measured according to the Cumulative Present Worth (CPW). CPW is a present value or discounted summation of all NLH incremental capital and operating costs under each future supply alternative. The CPW for Isolated Island is recorded at $8,810 million ($2010) for the planning period, while the CPW for the Interconnected Island alternative is $6,652 million ($2010). With a CPW difference of $2,158 million ($2010), the Interconnected Island alternative, which includes all costs for the Muskrat Falls and the Labrador-Island Link, is the preferred generation alternative recommended by NLH. Sensitivity analysis demonstrates the robustness of this conclusion. Moreover, the Interconnected Island alternative eliminates consumers' exposure to the uncertainties related to world oil prices and environmental liabilities related thereto. The integration of Muskrat Falls and the Labrador-Island Link into the island rate base will fundamentally change the cost structure for the Island ratepayers, providing price stability and increasing value with each passing year.

1 # Glossary

Term	Definition
Atmospheric Emissions	Gases and particles which are put into the air or emitted by various sources including nitrous oxide, chlorofluorocarbons and halocarbons and water vapor.
Basis of Design	A compilation of the fundamental criteria, principles and/or assumptions upon which Design Criteria and Engineering Design Briefs will be developed for a project.
Bipole Transmission Failure	Simultaneous loss of both poles of a bipole HVdc transmission system.
British Thermal Unit (BTU)	The amount of heat energy necessary to raise the temperature of one pound of water one degree Fahrenheit.
Bulk Transmission System	An interconnected group of electric transmission lines and associated equipment for moving or transferring electric energy in bulk between points of supply and points at which it is transformed for delivery over the distribution system lines to consumers, or is delivered to other electric systems. In the context of the transmission system on the island portion of the province the bulk transmission system generally refers to the 230 kV transmission system.
Bulk Power System	The part of the overall electricity system that includes the generation of electricity and the transmission of electricity over high-voltage transmission lines to distribution companies. This includes power generation facilities, transmission lines, interconnections between neighbouring transmission systems, and associated equipment. It does not include the local distribution of the electricity to homes and businesses.
Bus	An electrical conductor that serves as a common connection for two or more electrical circuits; may be in the form of rigid bars or stranded conductors or cables.
Capacity	The amount of electric power delivered or required for which a generator, turbine, transformer, transmission circuit, station, or system is rated by the manufacturer.
Capacity Factor	For any equipment, the ratio of the average load during a defined time period to the rated capacity.
Capital Structure	The composition of a company's capital in terms of equity and debt.
Carbon Capture and Storage (CCS)	CCS refers to the capture of carbon dioxide emissions from facilities before they are emitted, then transferring them to underground geological formations to ensure they do not escape into the atmosphere.
Circuit Breaker	A device used to interrupt or break an electrical circuit when an overload condition exists to protect electrical equipment.

Term	Definition
Co-Generation	Generation that produces electricity and another form of useful thermal energy (such as heat or steam), used for industrial, commercial, heating, or cooling purposes.
Combined Cycle Combustion Turbines (CCCT)	The combined cycle system incorporates two simple cycle systems into one. First a combustion turbine fired on natural gas or light fuel oil turns an electric generator. Next, the exhaust heat from the combustion turbine is used to produce steam that is passed through a steam turbine, which turns a second an electric generator. Thus, two single units, combustion turbine and steam turbine, are put together to minimize lost potential energy.
Commissioning	The process by which a power plant, apparatus, or building is approved for operation based on observed or measured operation that meets design specifications.
Composite Index	A grouping of equities, indexes or other factors combined in a standardized way, providing a useful statistical measure of overall market or sector performance over time.
Compound Average Growth Rate	The average year-over-year growth rate of an investment over a specified period of time.
Conservation and Demand Management (CDM)	Describes a range of programs and initiatives to encourage users to conserve electricity and use it more efficiently. It also includes efforts to decrease peak demand for electricity.
Converter Station	Facility consisting of all equipment and infrastructure associated with dc-to-ac or ac-to-dc power conversion and transmission.
Cost of Carbon	The cost, direct or indirect, associated with emitting carbon (usually in the form of greenhouse gases).
Cost of Debt	The cost of debt is the effective rate that a company pays on its current loans, bonds and various other forms of debt.
Cost of Service (COS)	The total amount of money, including return on invested capital, operation and maintenance costs, administrative costs, taxes and depreciation expense, to produce a utility service.
Cumulative Present Worth (CPW)	The present value of all incremental utility capital and operating costs incurred to reliably meet a specified load forecast given a prescribed set of reliability criteria.
Debt Service Costs	The interest expense for a specific period of time on borrowed money.
Discount Rate	The opportunity cost of capital used to discount future nominal cash values to present day
Discounted Cash Flow Analysis	The present value of future cash flows using the applicable discount rate.
Diversion Canal	An artificial canal constructed to divert water from one area to another.
Domestic Customer	Residential customers of NLH and NL Power.

Term	Definition
Economic Supply Price	That price, which when multiplied by output and discounted to present value, equals the total present value of all capital and operating costs of an investment.
Electrostatic Precipitators (ESP)	Pollution abatement equipment that reduces particulate emissions from thermal generating plant, such as Holyrood. Precipitators negatively charge the ash particles and collect them on positively charged collecting plates. This process collects flyash which is then transported to a treatment facility where it is conditioned with water and transferred to a truck for landfilling.
Energy	The total amount of electricity that the utility supplies or a customer uses over a period of time. The energy supplied to electricity consumers is usually recorded as kilowatt hours, megawatt hours (1000 kWhs), gigawatt hours (1000 MWhs), or terawatt hours (1000 GWhs).
Energy Efficiency	Refers to programs that are aimed at reducing the energy used by specific end-use devices and systems, typically without affecting the services provided. These programs reduce overall electricity consumption (reported in megawatt hours), often without explicit consideration for the timing of program-induced savings. Such savings are generally achieved by substituting technically more advanced equipment to produce the same level of end-use services (e.g. lighting, heating, motor drive) with less electricity. Examples include high-efficiency appliances, efficient lighting programs, high-efficiency heating, ventilating and air conditioning (HVAC) systems or control modifications, efficient building design, advanced electric motor drives, and heat recovery systems.
Enhanced Oil Recovery (EOR)	EOR is a generic term for techniques for increasing the amount of crude oil that can be extracted from an oil field
Equivalent Short Circuit Ratio (ESCR)	A measure of system strength for application of HVdc converter technology. It is defined as: ESCR = (Short circuit MVA at AC bus – MVA rating of filters)/Rated DC power
Escalation	Provision for changes in price levels driven by economic conditions. Includes inflation.
Federal Energy Regulatory Commission (FERC)	A regulatory agency within the United States Department of Energy having jurisdiction over interstate electricity sales, wholesale electric rates, hydroelectric licensing, natural gas transmission and related services pricing, oil pipeline rates and gas pipeline certification.
Firm Energy	Energy intended to be available at all times during a period of time.

Term	Definition
Firm Energy Capability	Firm energy capability for the hydroelectric resources is the maximum continuous energy able to be produced from those resources under the most adverse sequence of reservoir inflows occurring within the historical record. Firm energy capacity for the non-peaking thermal resources (Holyrood Thermal Generating Station) is based on allowances for maintenance and forced outages.
Firm Load	The load that is served 100 percent of the time.
Forced Outage Rate	The hours a generating unit, transmission line, or other facility is removed from service, divided by the sum of the hours it is removed from service, plus the total number of hours the facility was connected to the electricity system expressed as a percent.
Forebay	The portion of the reservoir at a hydroelectric plant that is immediately upstream of the generating station.
Fossil Fuel	Any naturally occurring organic fuel, such as petroleum, coal, and natural gas.
Generation Planning	Planning for the power and energy supplied by NLH, power supplied by NLH's customer-owned generation resources and NLH's bulk and retail electricity supply, including power purchases.
Generation Reliability Criteria	Criteria established to set the minimum level of reserve capacity and energy installed in the system to ensure an adequate supply for firm demand.
Gigawatt (GW)	One thousand megawatts (1,000 MW) or, one million kilowatts (1,000,000 kW) or one billion watts (1,000,000,000 watts) of electric power.
Gigawatt Hour (GWh)	One million kilowatt-hours of electric energy.
Greenhouse Gas (GHG)	Any gas that absorbs infra-red radiation in the atmosphere. Greenhouse gas/gasses. The principal GHG are carbon dioxide, methane, nitrous oxide, chlorofluorocarbons and halocarbons and water vapor.
Greenhouse Gas Intensity	The amount of greenhouse gas emissions per unit of output.
Grid	The layout of an electrical transmission or distribution system.
Head Pond	Another term for reservoir.
Heat Rate	A number that tells how efficient a fuel-burning power plant is. The heat rate equals the Btu content of the fuel input divided by the kilowatt-hours of energy output.
Heat Recovery Steam Generator (HRGS)	Generators that convert exhaust heat into steam that is used to power the turbines.

Term	Definition
Heavy Fuel Oil	The fuel oils remaining after the lighter oils have been distilled off during the refining process. Except for start-up and flame stabilization, virtually all petroleum used in steam plants is heavy oil.
High Voltage Direct Current (HVdc)	High voltage transmission system using direct current as opposed to the more common alternating current to transmit large quantities of power over long distances.
Industrial Load	The requirements for the island's larger industrial customers directly served by NLH.
In-Service	In operation and/or energized.
Installed Capacity	The capacity measured at the output terminals of all the generating units in a station, without deducting station service requirements.
Intake	The entrance to a turbine unit at a hydroelectric dam.
Interconnection (intertie)	The linkage of transmission lines between two utilities, enabling power to be moved in either direction.
Internal Rate of Return (IRR)	A widely reported measure of investor return on capital used in economic and financial analysis. It is that discount rate that makes net present value equal to zero and thus establishes a return to capital that the investor can then compare to a hurdle rate or own weighted cost of capital.
Kilowatt (kW)	A unit of electrical power equal to one thousand watts.
Kilowatt Hour (kWh)	A unit of electrical energy which is equivalent to one kilowatt of power used for one hour. One kilowatt-hour is equal to 1,000 watt-hours.
Levelized Unit Energy Costs (LUEC)	The present value of costs divided by the present value of output. A LUEC is useful for comparing the economic cost of one alternative against another. the LUEC is that constant price, which when multiplied by output and discounted, equals the present value of all project costs.
Life Extension	A term used to describe capital expenses which reduce operating and maintenance costs associated with continued operation of a generating unit.
Light Fuel Oil (LFO)	Lighter fuel oils distilled off during the refining process. Virtually all petroleum used in internal combustion and gas-turbine engines is light oil.
Line Commutated Converter Technology	The HVdc converter technology that uses power electronic devices called thyristors in the ac to dc and dc to ac conversion process.
Line To Ground Fault	When one phase of an ac power system (the line) comes in contact with a grounded object such as a tree.

Term	Definition
Liquefied Natural Gas (LNG)	Natural gas that has been condensed to a liquid, typically by cryogenically cooling the gas to minus 162 degrees Celsius (below zero).
Load	The amount of electric power delivered or required at any specific point or points on a system. The requirement originates at the energy-consuming equipment of the consumers.
Load Curtailment	Removal of pre-selected customer demand from a power system, as a result of the occurrence of an abnormal condition, in an effort to maintain the integrity of the system and minimize overall customer outages.
Load Shape	The variation in the magnitude of the load over a daily, weekly or annual period.
Loss of Load Hours (LOLH)	A probabilistic assessment of the risk that the electricity system will not be capable of serving the system's firm load for all hours of the year.
Loss Of Load Probability (LOLP)	A measure of expectation that system demand will exceed capacity during a given period, often expressed as the expected number of days per year (e.g., one day in ten years).
Low Nox Burner	Burners designed to control fuel and air mixing at each burner in order to create larger and more branched flames. Peak flame temperature is thereby reduced, and results in less NOx formation. The improved flame structure also reduces the amount of oxygen available in the hottest part of the flame thus improving burner efficiency.
Megawatt (MW)	A unit of electrical power equal to one million watts or one thousand kilowatts.
Megawatt Hour (MWh)	One million watt-hours of electric energy. A unit of electrical energy which equals one megawatt of power used for one hour.
Meteorological Loading (Wind And Ice)	Accumulated ice or combined ice and wind loadings on transmission lines.
Million British Thermal Units (MBTU)	One million British thermal units.
Net Head	Net head is the gross head (vertical distance between the intake structure and where the water leaves the turbine) minus pressure losses due to friction and turbulence.
Normalized Weather Basis	Adjusted utility sales to account for warmer or colder weather conditions for a given year compared to historical normal weather conditions.
Non-Dispatchable Generation	Generation that cannot be dispatched by the System Operator and/or cannot be counted on at specific times is non-dispatchable. Examples are wind and solar because the energy source is not always available.

Term	Definition
Non-Utility Generator (NUG)	An electricity producer which does not have a mandate or obligation to supply electricity to the public.
North American Electric Reliability Corporation (NERC)	As a reaction to the 1967 New York City black out, the electric utility industry formed a council in 1968 to promote the reliability and adequacy of bulk power supply in the electric utility systems of North America. NERC consists of ten regional reliability councils and encompasses essentially all the power regions of the contiguous United States, Canada and a small portion of Mexico. There is also one affiliate member in Alaska.
North American Grid	A system of power generation, transmission, and distribution that delivers electricity to the United States, Canada and a portion of Mexico.
Operating And Maintenance (O&M) Costs	Costs associated with the ongoing operation and maintenance of a facility.
Peak Demand	The highest level of electricity consumption that the utility has to supply to the system at any one time. Peak demand on the electrical system is measured in megawatts (MW) and occurs in the winter on the Island Grid.
Penstock	A conduit that conveys water from the intake to the turbine.
Planning Load Forecast (PLF)	NLH's outlook for expected total electricity consumption and peak demand in the province for the next twenty years.
Power Purchase Agreement (PPA)	Bilateral wholesale or retail power contract.
Power Purchase Price	The unit price paid for energy delivered.
Power Rating	The capacity rating of a piece of electrical equipment measured in MW or MVA.
Powerhouse	A structure that contains the turbine and generator of a power project.
Price Elasticity	The percentage change in the quantity divided by the percentage change in the price.
Producer Price Indices (PPIs)	An index showing the monthly change in wholesale prices.
Radial Transmission Line	A transmission line that is connected to the interconnected grid on one end and load on the other end.
Rate Base	The value of property upon which a utility is permitted to earn a specified rate of return as established by a regulatory authority. The rate base generally represents the value of plant and property used by the utility in providing service.

Term	Definition
Reactive Power	The portion of electricity that establishes and sustains the electric and magnetic fields of alternating-current equipment. Reactive power must be supplied to most types of magnetic equipment, such as motors and transformers. Reactive power is provided by generators, synchronous condensers, or electrostatic equipment such as capacitors and directly influences electric system voltage. It is a derived value equal to the vector difference between the apparent power and the real power. It is usually expressed as kilovolt-amperes reactive (kVAR) or megavolt-ampere reactive (MVAR).
Real (or Constant) Dollars	Nominal dollars(i.e. dollars of the day) adjusted to remove the effects of general inflation from the price level. Real (or constant) dollars are normally referenced to a specific point in time, such as '$2010'.
Recall Power/Contract	A 300 MW block of power which can be recalled under the existing power contract between Hydro Quebec and CF(L)Co for use in Labrador. The 300 MW block is sold to NLH in its entirety.
Regional Reliability Organization	An entity that ensures that a defined area of the Bulk Electric System is reliable, adequate and secure. A member of the North American Electric Reliability Corporation.
Regulated Asset	An asset whose cost is included in the rate base.

Regulated Revenue Requirement	NLH's regulated revenue requirement is the sum of:
	• Operating and maintenance expenses,
	• Fossil fuel costs,
	• Purchase power expenses from third or related parties,
	• Annual capital charges, comprised of:
	    ○ Depreciation,
	    ○ Return on Rate Base, comprised of
	        ▪ Interest expenses, and
	        ▪ Return on equity

Reliability	The extent to which equipment, systems and facilities perform as originally intended. This encompasses the confidence in the soundness or integrity of the equipment based on forced outage and derating experience, maintenance effort, the output of the equipment in terms of efficiency and capacity, unit availability and the remaining service life.
Reserve	The extra generating capability that an electric utility needs, above and beyond the highest demand level it is required to supply to meet its user's needs.

Term	Definition
Reserve Capacity	The amount of power that can be produced at a given point in time by generating units that are kept available in case of special need. This capacity may be used when unusually high power demand occurs, or when other generating units are off-line for maintenance, repair or refueling.
Reservoir	The space behind and body of water held back by a dam.
Retail Rate	The rate for electricity paid by the customer.
Return On Rate Base	Equal to a return on equity plus the cost of debt.
Return on Equity	Compensation for the investment of capital; i.e., earnings. Regulated public utilities entitled to charge rates that permit them to earn a reasonable return on their equity invested.
Revenue Requirement Model (RRM)	A financial planning process and model that builds up the annual costs for existing operating expenses and capital assets, with the incremental operating expenses and capital charges for a future long-term generation expansion plan. The outcome is NLH's annual regulated revenue requirement.
Run of the River	A hydroelectric plant which depends chiefly on the flow of a stream as it occurs for generation, as opposed to a storage project, which has space available to store water from one season to another. Some run-of-river projects have a limited storage capacity (pondage) which permits them to regulate streamflow on a daily or weekly basis.
Seasonal Load Pattern	The changes in load from season to season. In Newfoundland and Labrador the demand for electricity is higher during the winter months and lower during the summer months.
Sensitivity Analysis	Analysis of the impact on the overall costs of a project due to variation in the key input parameters.
Service Life	The expected useful lifespan of a generating unit.
Service Territory	The territory in which a utility system is required or has the right to supply service to ultimate customers.
Simple Cycle Combustion Turbines (CT)	A fuel-fired turbine engine used to drive an electric generator. Combustion turbines, because of their generally rapid firing time, are used to meet short-term peak demands placed on power systems.
Single Pole Reclose	The act of opening the phase breaker on both ends of a line that is experiencing a line to ground fault, isolating the faulted phase while the two unaffected phases remain in service. After waiting a predetermined time one of the opened phase breakers is closed to test the line to determine if the fault has cleared. If it has cleared, the remaining opened phase breaker closes restoring the line to full service. If the fault has not cleared all remaining phase breakers connected to the line are opened and the line is removed from service.

Term	Definition
Solar Insolation	The total amount of solar radiation (direct, diffuse, and reflected) striking a surface exposed to the sky.
Spinning Reserve	Unloaded generation that is synchronized and ready to serve additional demand.
Standby Generation	Generation that is available, as needed, to supplement a utility system or another utility. The generation is not regularly used.
Storage Capacity	The amount of energy an energy storage device or system can store.
Sub-Transmission	These lines carry voltages reduced from the major transmission line system, usually 69 kV.
Synchronous Condenser	A specialized synchronous machine whose shaft is not attached to anything, but spins freely. Its purpose is not to convert mechanical power to electrical power like synchronous generators but rather to assist in voltage control of the transmission system to which it is connected.
System Contingency	A possible event for which preparations are made. Typically the loss of generating capacity or a transmission element.
System Inertia	The stored rotating energy in the system.
System Planning	System planning is comprised of load forecasting, assessment of the adequacy of existing generation, transmission and distribution capacity, identification of alternatives to mitigate shortfalls and determination of the most suitable option to correct the deficiency.
System Reliability	Electric system reliability has two components-- adequacy and security. Adequacy is the ability of the electric system to supply the aggregate electrical demand and energy requirements of the customers at all times, taking into account scheduled and unscheduled outages of system facilities. Security is the ability of the electric system to withstand sudden disturbances such as electric short circuits or unanticipated loss of system facilities.
Tailrace	A watercourse that carries water away from a turbine or a powerhouse.
Terawatt Hour (TWh)	One thousand gigawatt hours.
Terminal Station	A NLH high voltage electrical station with a rating of 230 kV, 138 kV, 69/66 kV used to change the voltage level or provide a switching point for a number of transmission lines.
Thermally Constrained	As the load on a transmission line increases the temperature of the transmission line conductor increases and the conductor begins to elongate. The elongation of the conductor causes it to sag towards the ground between its attachment points. A transmission line is said to be thermally constrained when the loading conditions and ambient conditions are such that to further increase the line loading would result in the conductor sagging below the required minimum ground clearance for safe operation.

Term	Definition
Transformer	A device used to transfer electric energy from one circuit to another, through a pair of multiply wound, inductively coupled wire coils that affect such a transfer with a change in voltage, current, phase, or other electric characteristic.
Transmission	The network of high voltage lines, transformers and switches used to move electrical power from generators to the distribution system. Also utilized to interconnect different utility systems and independent power producers together into a synchronized network. Transmission is considered to end when the energy is transformed for distribution to the consumer.
Turbine	The part of a generating unit usually consisting of a series of curved vanes or blades on a central spindle, which is spun by the force of water, steam or hot gas to drive an electric generator. Turbines convert the kinetic energy of such fluids to mechanical energy through the principles of impulse and reaction, or a measure of the two.
Underfrequency Load Shedding	The power system must operate within a very tight tolerance about the nominal system frequency of 60 Hz. Governor action on electric generators operate to maintain the system frequency at 60 Hz as load increases or decreases on the system. This is similar to the cruise control on a car that maintains the set speed as the car encounter hills. In the electrical system if there is a very large increase in load or a loss of generation the frequency will drop too quickly for the on line generators to react. Tripping or shedding predefined blocks of load in an under frequency load shedding scheme is employed to rebalance the system load with the on line generation and restore the system frequency to normal.
Utility Load	The domestic and general service class load requirements for the service territories of Newfoundland Power and NLH Rural.
Variable Costs	The total costs incurred to produce energy, excluding fixed costs which are incurred regardless of whether the resource is operating. Variable costs usually include fuel, increased maintenance and additional labor.
Ventyx Strategist®	A software package used by NLH to carry out least cost generation expansion planning.
Voltage	The electrical force or potential that causes a current to flow in a circuit (just as pressure causes water to flow in a pipe). Voltage is measured in volts (V) or kilovolts (kV). 1 kV = 1000 V.

Term	Definition
Voltage Constrained	As load increases on a transmission system the voltage on the system begins to fall. Voltage support devices such as capacitors, synchronous condensers and local generators are employed to maintain acceptable voltages on the system. As load continues to increase all on line voltage support devices will reach their maximum output levels. At this point the system is said to be voltage constrained. Loading beyond this level will lead to unacceptably low voltages, potential damage to customer equipment and ultimately voltage collapse and an outage if load continues to increase.
Voltage Support	The application of synchronous generators, synchronous condensers, capacitor banks and other reactive power sources to maintain the transmission system voltage level within acceptable limits as load on the system increases.
Water Management Agreement	Agreement in place between in place between Nalcor and Churchill Falls (Labrador) Corporation that requires that the operation of Muskrat Falls be coordinated with that of Churchill Falls.
Watershed	The area drained by a single lake or river and its tributaries; a drainage basin.
Watt	The scientific unit of electric power; a rate of doing work at the rate of one joule per second. A typical light bulb is rated 25, 40, 60 or 100 watts. One horse power is 746 watts.
Watt Hour	One watt of power expended for one hour.
Weighted Average Cost Of Capital (WACC)	The cost of debt and the cost equity weighted together as per the debt: equity capitalization of a company.
Wet Limestone Flue Gas Desulphurization (FGD) Systems	Pollution abatement equipment that reduces sulphur dioxide emissions from thermal generating plant, such as the Holyrood Plant. Scrubbers use limestone to capture and neutralize sulphur dioxide. The limestone reacts with sulphur dioxide in an absorber tower. This process creates gypsum which is then dewatered and the gypsum is transferred by a conveyor to a storage building. The waste product is then landfilled.
Wholesale Rate	The price Newfoundland Power pays for the wholesale delivery of power and energy from NLH.

Sources:

(1) Bonneville Power Administration, *Definitions*, webpage, 2011
http://www.bpa.gov/corporate/pubs/definitions/
(2) The California Energy Commission, *Glossary of Energy Terms*, webpage, 2011
http://www.eia.gov/cneaf/electricity/page/glossary.html
(3) Canadian Electricity Association, *Glossary*, webpage, 2011
http://www.electricity.ca/glossary.php
(4) Duke Energy Corporation, *Glossary of Terms*, webpage, 2011
http://www.duke-energy.com/about-energy/glossary-of-energy-terms.asp
(5) The Financial Times Ltd., *The Financial Times Lexicon*, website, 2011
http://lexicon.ft.com/

(6) Government of Canada, ecoAction, *ecoENERGY for Renewable Heat*, 2008 http://www.ecoaction.gc.ca/ecoenergy-ecoenergie/heat-chauffage/marbekfinalreport-rapportfinalmarbek-eng.cfm

(7) Government of the United States, Energy Information Administration, Electricity Terms, webpage. 2011 http://www.eia.gov/cneaf/electricity/page/glossary.html

(8) International Energy Agency, IEA Clean Coal Centre, *Low NOx Burners*, webpage, 2011 http://www.iea-coal.org.uk/site/2010/database-section/ccts/low-nox-burners?

(9) ISO New England, Glossary & Acronyms, webpage, 2011 http://www.iso-ne.com/support/training/glossary/index.html

(10) The New York Times Company, *Glossary of Financial and Business Terms*, webpage, 2011 http://www.nytimes.com/library/financial/glossary/bfglosa.htm

(11) North American Electric Reliability Corporation (NERC), *Glossary of Terms Used in Reliability Standards*, 2008. http://www.nerc.com/files/Glossary_12Feb08.pdf

(12) North American Electric Reliability Corporation (NERC), *Understanding the Grid: Reliability Terminology*, webpage, 2011 http://www.nerc.com/page.php?cid=1%7C15%7C122

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

Volume 2

November 10, 2011

Note to Reader

This report references exhibits and responses to requests for information filed with the Newfoundland and Labrador Board of Commissioners of Public Utilities (the Board) by Nalcor Energy. Exhibits and responses to requests for information (RFIs) are classified as either public or confidential. Confidential exhibits (CEs) have been deemed so by Nalcor where the information contained within is of a commercially sensitive nature. All public exhibits, including abridged or redacted versions of confidential exhibits, are available at the Board's website

Exhibits:	http://www.pub.nf.ca/applications/MuskratFalls2011/nalcordocs.htm
Responses to RFIs	http://www.pub.nf.ca/applications/MuskratFalls2011/rfi.htm
Public CE's:	http://www.pub.nl.ca/applications/MuskratFalls2011/abridge.htm

Table of Contents

List of Figures

List of Tables

List of Acronyms

Acronym	Definition
AACE	Association for Advancement to Cost Engineering
ac	Alternating current
AFE	Authorization for Expenditure
AIFR	All Injury Frequency Rate
C-CORE	Centre for Cold Ocean Resource Engineering
CEO	Chief Executive Officer
CERA	Cambridge Energy Associates
CF	Churchill Falls
CFRD	Concrete Face Rockfill Dam
CPU	Central Processing Unit
CPW	Cumulative Present Worth
CSC	Construction Sector Council
DG2	Decision Gate 2
DG3	Decision Gate 3
DWA	Double Wire Armor
EA	Environmental Assessment
EMS	Environmental Management System
ENR	Engineering News Record
EPC	Engineering, Procurement and Construction
EPCI	Engineering, Procurement, Construction and Installation
EPCM	Engineering, Procurement and Construction Management
FSL	Full Supply Level
GNL	Government of Newfoundland and Labrador
HDD	Horizontal Directional Drilling
HQT	Hydro-Quebec TransEnergie
HSE	Health, Safety and Environment
HVac	High Voltage Alternating Current
HVdc	High Voltage Direct Current
IBA	Impacts and Benefits Agreement
IPA	International Project Analysis Inc.
IPR	Independent Project Review
km	Kilometre
kV	Kilovolt
LCC	Line Communicated Converter
LCP	Lower Churchill Project
LIL	Labrador-Island Transmission Link
LOC	Letter of Credit
LSL	Low Supply Level
m	Metre
MF	Muskrat Falls
MFL	Maximum Flood Level
MI	Mass Impregnated
ML	Maritime Link
MoC	Management of Change
Mt	Mega tonne
MVAR	Mega VAR (Mega Volt * Amps Reactive)
MW	Megawatt
NL	Newfoundland and Labrador

Acronym	Definition
NLH	Newfoundland and Labrador Hydro
NS	Nova Scotia
OHGW	Overhead Ground Wire
OPGW	Optical Ground Wire
PCS	Project Control Schedule
PEP	Project Execution Plan
pf	Power Factor
PMF	Probable Maximum Flood
PMT	Project Management Team
PO	Purchase Order
QA/QC	Quality Assurance/Quality Control
RCC	Roller Compacted Concrete
RFI	Request for Information
RFP	Request for Proposal
RFQ	Request for Quotation
ROW	Right of Way
SCADA	Supervisory control and data acquisition
SLD	Single Line Diagram
SOBI	Strait of Belle Isle
TL	Transmission Line
TLH	Trans Labrador Highway
TRIFR	Total Reportable Incident Frequency
TWh	Terawatt Hour
VP	Vice President
VSC	Voltage Source Converter
WBS	Work Breakdown Structure
WTO	Work Task Order

1.0 Purpose and Scope

1.1 Purpose

The purpose of Volume II of this submission is to provide an overview of the Projects which were defined in the Board reference question as the Muskrat Falls generating facility (Muskrat Falls) and the Labrador-Island Link transmission line (LIL)[1]. Moreover the purpose of this volume is to describe the basis of the recommended project configuration at Decision Gate 2 (DG2). Key areas of focus include:

- a description of the facilities to be constructed (i.e. the Basis of Design), including how the designs have matured since studies completed in 1998;
- the Project delivery approach selected by Nalcor Energy (Nalcor) to engineer and construct the facilities; and
- an overview of the Decision Gate 2 cost and schedule basis.

1.2 Report Structure

In describing the Muskrat Falls and LIL projects, this volume of the report begins with an introduction and purpose. Section 2 provides a description of the Projects, including how the design of each project component has evolved since the late 1990's and concludes with a summary of the Basis of Design of each project component. Section 3 discusses the project execution strategy with a focus on the Gateway Decision Process and the Independent Project Review process that is used to assist in the decision making process at each Decision Gate. Section 4 then discusses the project delivery strategy, including a review of how the Engineering Procurement Construction Management (EPCM) contract model was selected, the roles of Nalcor and the EPCM consultant and the approach and sequencing of construction. Section 4 also includes a discussion of the management controls and systems that have been established for the LCP, including a discussion of the risk management

1 When described collectively, the Muskrat Falls and LIL are referred to as the Lower Churchill Project or the LCP. When discussed individually, they are referred to as Muskrat Falls and LIL

processes employed by the LCP Project Management Team (PMT). Section 5 provides an overview of the Decision Gate 2 (DG2) capital cost estimate and schedule, including the process used to develop the estimate, the key components of the estimate and a discussion of the project schedule. Section 6 provides a summary of Volume 2 of the submission.

2.0 Project Description

Section 2 begins with an overview of the hydroelectric capacity of the Churchill River in Labrador and identifies the two phases of construction of the Lower Churchill Project. It outlines how the project design evolved from alternatives that were considered in 1998 to what was finally recommended following the system planning exercise described in Volume 1. This section concludes with a comprehensive overview of the Basis of Design.

2.1 Background

The hydroelectric potential of the Churchill river in Labrador has been recognized for more than 80 years. The existing 5,428 MW Churchill Falls Generating Station, which began producing power in 1971, harnesses about 65 percent of the river's potential generating capacity. The remaining 35 percent is located at two sites on the Lower Churchill River: 1) Gull Island, located 225 kilometres downstream from the existing Churchill Falls Generating Station, and 2) Muskrat Falls, located a further 60 kilometres downstream. Combined, these two installations will have a capacity of over 3,000 megawatts (MW) and the potential to produce almost 17 terawatt hours (TWh) of electricity annually.

Extensive pre-feasibility work has been undertaken for Muskrat Falls, Gull Island and the Labrador-Island Transmission Link. This work has included the progression of the environmental assessment process, the finalization of a Water Management Agreement, negotiations for an Impacts and Benefits Agreement (IBA) with Innu Nation of Labrador, the development of a Benefits Strategy with the Government of Newfoundland and Labrador, the completion of extensive engineering studies and field work, the development of a financing approach and an understanding of cost, schedule and risk.

Development of the Lower Churchill will proceed in two phases:

<u>1) Phase I, as illustrated in Figure 1, will include:</u>

- the 824 MW capacity Muskrat Falls generating facility with interconnecting HVac transmission facilities between Muskrat Falls and Churchill Falls;

- the Labrador-Island Transmission HVdc Link and associated island system upgrades; and
- the Maritime Link from the island of Newfoundland to Nova Scotia with associated island system upgrades.

<u>2) Phase II, as illustrated in Figure 2, is expected to consist of:</u>

- the 2,250 MW capacity Gull Island generating facility
- associated HVac transmission in Labrador;
- associated export transmission.

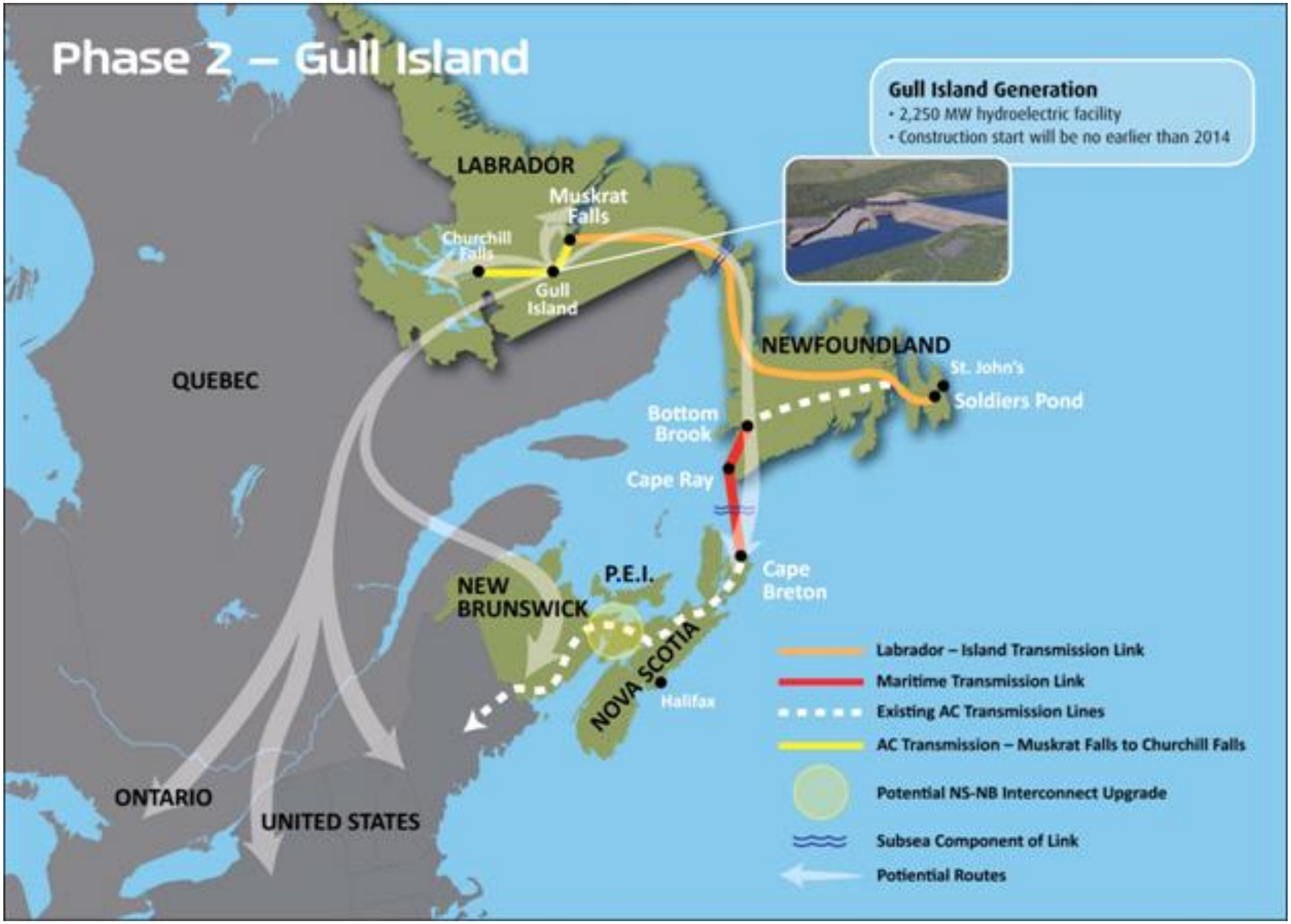
Consistent with the review commissioned by the Government of Newfoundland and Labrador (see Volume 1, Section 1), this submission focuses only on parts of Phase I. The Maritime Link component is not included in this review, however, it is sometimes referenced due to the fact that there are joint management practices being contemplated that also encompass the Maritime Link.

Figure 3 recaps the key milestones and events that have occurred to date and concludes with the Decision Gate 2 milestone on November 16, 2010.

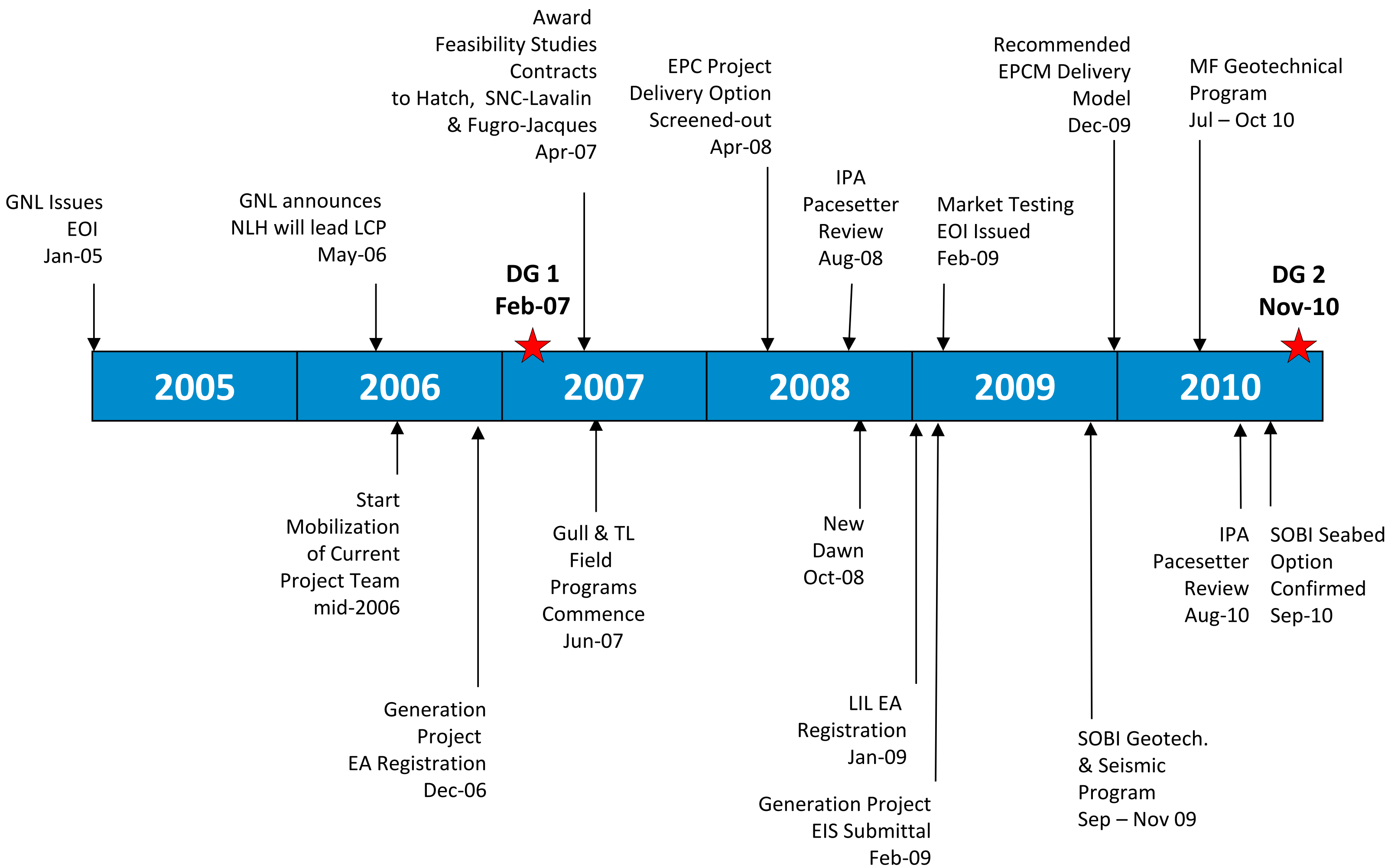
1 **Figure 1: Lower Churchill Project – Phase I**

2

Figure 2: Lower Churchill Project – Phase II



1 **Figure 3: Key Project Milestones and Events – Gateway Phases 1 and 2**



2.2 Muskrat Falls and LIL Design Evolution from 1998 to DG2

As a result of time, improved technology and a better understanding of Muskrat Falls, the development concepts have matured since studies were conducted in 1998. This section explains that evolution and describes the basis of design which supports the Interconnected Island generation expansion plan recommended in Volume 1.

Note: The following section is an abbreviated version of Exhibit 30: Lower Churchill Project Design Progression 1998-2011[2].

2.2.1 Generating Facilities

In 1998, Newfoundland and Labrador Hydro (NLH) conducted a final feasibility study for the hydroelectric generating facility at Muskrat Falls. The study concluded with a short list of three potential development scenarios, referred to as "variants." Each of these variants, Variant 7, Variant 10 and Variant 11, represent a different physical layout (e.g. dam locations and types, powerhouse locations, etc.) to develop the Muskrat Falls hydro potential.

<u>Recommended Layout in 1998</u>

Following an analysis of comparative costs, schedule and risk, the 1998 analysis recommended that Variant 7 be selected as the layout of choice for further development. This option was attractive because it did not require the construction of a new bridge to access the south side of the river to commence construction, which would extend the overall construction schedule considerably. The conceptual development for Variant 7 was described in the Final Feasibility Report by SNC-AGRA in January 1999[3].

Variant 7 is an 824 MW hydroelectric development. It includes two tunnels through the rock knoll on the north side of the Churchill River for diversion of the river during construction, a four unit powerhouse with Kaplan/propeller turbines, a gated spillway constructed in the river channel, a north overflow dam with a partial fixed crest and an inflatable rubber dam, and a south closure dam. Permanent access to the powerhouse is from the north side of the

2 Nalcor Energy, Lower Churchill Project Design Progression 1998-2011 (Exhibit 30)
3 SNC-AGRA, Final Feasibility Study re Muskrat Falls, 1999 (Exhibit 19)

river, around the rock knoll of the North Spur and across the top of the dams, spillway and intake structures.

Changes Since 1988

With construction of the Trans Labrador Highway (TLH), the Government of Newfoundland and Labrador built a bridge across the Churchill river approximately 18 km downstream of Muskrat Falls. This provides access to the Muskrat Falls site along the south side of the river, an alternative that did not exist in 1998. Consequently, Nalcor commissioned a new review of the potential development options for Muskrat Falls. This review was carried out by SNC-Lavalin in 2007 and is called Review of Variants[4].

New Layout Recommendations

The 2007 study revisited Variants 7, 10 and 11 with the knowledge that access to the south side of the Churchill River was now available. Following an analysis of comparative costs, schedule and risks, Variant 10 proved to be the most attractive development layout. With Variant 10, first power could be achieved nine months ahead of Variant 11 and ten months ahead of Variant 7. This is primarily due to the lack of a requirement to construct diversion tunnels.

In addition, since 1998, Nalcor has conducted extensive consultation initiatives with a variety of key stakeholders, including Innu Nation of Labrador. During these consultations, it was revealed that the rock knoll at Muskrat Falls has spiritual and cultural significance to the Labrador Innu. Variant 10 eliminates the need for river diversion through the rock knoll and avoids the building of diversion tunnels through this culturally sensitive location. This, combined with the cost, schedule and risk advantages, make Variant 10 the preferred development alternative.

Further studies were initiated as part of Nalcor's Gateway Phase 2 engineering work, including evaluating spillway alternatives, understanding river operations during diversion, filling of the reservoir, construction flood studies, probable maximum flood (PMF) studies, dam break studies and associated inundation mapping, ice studies, and site access studies.

[4] SNC-Lavalin, Muskrat Falls Hydroelectric Project Review of Variants, 2008. (Exhibit CE-15)

The results of these studies led to the decision to move forward with additional geotechnical field investigations in 2010[5].

2.2.2 HVac Transmission System in Labrador

A number of transmission alternatives have been considered to interconnect the Lower Churchill generating sites to the Labrador transmission grid.

Previous planning with Hydro-Quebec for integration of Gull Island had concluded that 735 kV transmission facilities between Gull Island and Churchill Falls, as well as 735 kV facilities between Gull Island and the Quebec transmission system would be required to integrate Gull Island. Given the proximity of Muskrat Falls to Gull Island, a 230 kV interconnection was proposed between these sites.

With a focus on the Muskrat Falls site being developed first, lower voltage (and lower cost) options were evaluated to develop a transmission solution that satisfied reliability requirements. The results of this initial analysis indicated a requirement for two 345 kV transmission lines that link Muskrat Falls and Churchill Falls, while at the same time maintaining flexibility for future integration with Gull Island[6].

2.2.3 Labrador-Island Transmission Link

The original configuration of the Labrador-Island HVdc Link (LIL) was based on a system proposed in 1998, with an 800 MW transmission system from Gull Island to Soldiers Pond on the Avalon Peninsula having an overload capacity on each pole of 100 percent (800 MW) for 10 minutes and 50 percent (600 MW) continuously.

One transmission option considered for Gull Island was the development of a 1600 MW multi-terminal HVdc system interconnecting Gull Island with Soldiers Pond and Salisbury, NB. A number of integration studies were completed to evaluate the performance of this alternative. As part of the Voltage and Conductor Optimization Study[7], voltages of ± 400, ±

[5] SNC-Lavalin, MF Site Investigations (Exhibits CE-19 to 26).
[6] Hatch, Voltage and Conductor Optimization Study, 2008. (CE-01)
[7] Exhibit CE-01

450 and ± 500 kV dc were considered for the transmission system and Mass Impregnated (MI) cables were considered for the Strait of Belle Isle (SOBI) Crossing.

For Muskrat Falls it was determined that the HVdc link should be sized at 900 MW based on the size of the Muskrat Falls plant and the amount of energy required to meet the domestic needs of the island[8].

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 were acceptable. Under this scenario, each pole of the bi-pole system would be rated at 450MW with 100 percent overload protection for 10 minutes and 50 percent overload protection for continuous operation[9].

2.2.4 Strait of Belle Isle Cable Crossing

Part of the feasibility engineering performed during Gateway Phase 2 involved determining the preferred solution for extending the HVdc transmission system across the Strait of Belle Isle (SOBI). Two options were considered for detailed study:

1. construction of a full-length cable conduit across SOBI with HVdc cables installed in the conduit; and
2. a seabed crossing with HVdc cables installed on or near the seabed with appropriate protection features.

Studies were led by Nalcor and included an extensive review of existing information from reports in Nalcor's archives along with extensive work carried out by national and international experts. This included an extensive field program in 2009 which culminated in a series of reports and workshops that led to a decision regarding the optimal approach[10].

---

8 Nalcor Energy, Historical Summary of HVdc System, (Exhibit 23)
9 Nalcor Energy, Historical Summary of the Labrador – Island HVdc System Configuration for the LCP (1974-Present). (Exhibit CE-32)
10 Exhibits CE-40 to 44

Using a risk-informed decision analysis process, the risks associated with the two crossing alternatives were compared by Nalcor. From this process it was concluded that several risks associated with the conduit crossing option were deemed to be unacceptable. These included geological risk, schedule risk, cost and schedule overrun exposure, safety during construction, and risk with respect to fall-back options should the conduit be abandoned part way through construction. Conversely, no unacceptable risks were identified for the seabed crossing option. This option was therefore chosen as the method for installing HVdc cables across the Strait of Belle Isle, and formed the basis of the DG2 recommendation[11].

<u>The Use of Submarine Cables</u>

As indicated in Figure 4, there are many other examples of power cables installed on the ocean floor, particularly in Europe. HVdc submarine cables were first introduced in 1954 to connect the island of Gotland to the mainland of Sweden. The project involved approximately 100 km of cable. The technology is well proven at distances far greater than the 18 km across the Strait.

[11] Nalcor Energy, SOBI Decision Recommendation. (Exhibit 37)

Figure 4: Submarine Cables in Operation in Europe

2.3 Basis of Design at Decision Gate 2

The Basis of Design is the result of extensive studies and field investigations carried out by Nalcor's Project Team since 2006. It recommended the preferred development concept and formed the foundation upon which the DG2 cost and schedule estimates were prepared. The Basis of Design presented below is extracted from Section 6 of Exhibit 30[12], which provides the definitive description of the Basis of Design.

The Decision Gate 2 Basis of Design reflects the facility's design and construction plans as required to meet the reliability criteria, and the island of Newfoundland's long-term energy and capacity needs. The design assumptions in the Basis of Design respect the following principles:

[12] Nalcor Energy, Lower Churchill Project Design Progression, 1998-2011. (Exhibit 30)

- Only proven technologies will be considered, unless it can be clearly demonstrated that emerging technologies can be as reliable and provide significant cost and/or schedule savings.
- Local climatic/service conditions such as ambient temperature, elevation, humidity, sea temperature, sea currents and wind will be respected throughout the Project.
- All hydroelectric plants and transmission systems will be remotely operated and monitored from NLH's Energy Control Centre.
- Environmental mitigation and rehabilitation will be designed prior to issuing construction contracts for tender.
- The designs will assume the use of existing transportation infrastructure to the maximum extent possible, in particular, existing roads, bridges, railways and wharfs.
- Standard utility practice will be observed.
- Fail Safe design principles will be employed.
- Principles of life cycle cost analysis will be employed.
- The designs will be consistent with Nalcor's safety and health program.
- The designs will be consistent with Nalcor's environmental policy and guiding principles.
- The designs will be consistent with Nalcor's asset management philosophy and approach.
- The designs will be consistent with all applicable governing standards, codes, acts and regulations.
- All assets and systems will be designed to ensure safety, reliability, efficiency and minimal impact to the environment.

2.3.1 Muskrat Falls Generating Facility and HVac Interconnect to Churchill Falls

The key elements of the Basis of Design for the Muskrat Falls Generating Facility and HVac interconnect to Churchill Falls can be broken down into project components as described in the following sections.

<u>Site Access</u>

- Site roads to be gravel surfaced unless conditions dictate otherwise (e.g. to limit dust and flying stones in areas such as accommodations complex and other site facilities).
- Permanent site access from south, along south side of river via the TLH.
- Temporary site access to north side from the TLH.

<u>Permanent Accommodations</u>

- No permanent accommodations required.

<u>Temporary Site Facilities and Accommodation Complexes</u>

- Staged, modular construction to accommodate up to 1,500 persons with appropriate offices, cooking, dining, sleeping, washing, medical, fire fighting, entertainment, recreational, power, water, sewage, and other life support facilities at site, within the project area, and at other locations, yet to be determined.
- Main site facilities to be located on south side of river.
- Includes substation and distribution system for construction power supplied from NLH and backup diesel generation at the site.
- Voice and data communication systems.
- Designed for removal following construction.

<u>Construction Power and Telecoms</u>

- Construction power will be sourced from NLH whenever practicable.
- Construction communication system required.

<u>Reservoir</u>

- Full Supply Level (FSL) = 39 m; Low Supply Level (LSL) = 38.5 m; Maximum Flood Level (MFL) = 44 m (all elevations above sea level).
- Remove all trees that grow in, or extend into the area between 3 m above FSL and 3 m below LSL, except where determined otherwise by the reservoir preparation strategy.
- Trash management system required for the reservoir.

- Fish habitat will be based on compensation strategy agreed with the Department of Fisheries and Oceans.

Diversion

- Through spillway structure.
- Capacity = 5,930 m^3/s.
- Fish compensation flow will be approximately 30 percent of mean annual flow.
- Fish compensation flow will be through spillway structure.

Dams and Cofferdams

- Main dams are to be Roller Compacted Concrete (RCC).
- Development flood capacity is based on Probable Maximum Flood (PMF).
- South RCC dam crest elevation of 45.5 m.
- North RCC dam to be an overflow dam with a crest elevation of 39.5 m.
- All dams are to be founded directly on bedrock.
- Cofferdams are to be earth/rock fill dams.

Spillway (Gated Section)

- Concrete structure in rock excavation.
- Capacity = PMF in conjunction with North RCC Dam at MFL elevation of 44 m.
- Spillway sill at elevation 5.0 m.
- Gates with heating and hoisting mechanisms designed for severe cold climate operation.
- One set (upstream and downstream) interchangeable steel stoplogs with a permanent hoist system.

Tailrace

- Draft tubes discharge directly into river in rock excavation.

Intakes

- Approach channel in open cut earth/rock excavation and designed to eliminate frazil ice.
- Concrete structure in rock excavation.
- Four intakes (one per unit).
- Four sets of vertical lift operating gates with individual wire rope hoists in heated enclosures.
- One set of bulkhead gates with a permanent hoist system.
- Four sets of removable steel trash racks.

Penstocks

- No penstocks; four individual water passages in concrete (close-coupled intake/powerhouse).

Powerhouse Civil Works

- Concrete structure in rock excavation.
- Structural steel super-structure with metal cladding.
- Four-unit powerhouse with maintenance bay large enough to assemble one complete turbine/generator unit, plus assembly and transfer of one extra rotor with provision for an unloading area.
- Area for offices, maintenance shops and warehouse.
- After completion of turbine/generator installation, the maintenance bay may be reduced in size to accommodate the dismantling of one entire turbine/generator unit only.
- Offices, maintenance shops, and warehouse may occupy the remaining area of the maintenance bay.
- Two sets of draft tube stoplogs with a permanent hoist system in a heated enclosure.

Turbines and Generators

- Four 206 MW turbines, approximately, @ 0.90 power factor (pf) vertical axis generators.
- Four Kaplan turbines with cavitation resistant design.
- Unitized approach from intake to generator step-up transformer.
- Failure of any equipment/system of one unit not to affect the operation of the remaining units.

Electrical Ancillary Equipment

- Dual dc battery system.
- A minimum of two sources of station service.
- Dual digital protection systems.
- A distributed digital control and monitoring system.
- Dual central processing unit (CPU) for control system functions.
- Two standby emergency diesel generators, in separate locations, complete with fuel storage systems.

Mechanical Ancillary Equipment

- Separate high and low pressure compressed air systems.
- Separate service, domestic, and fire water systems.
- HVAC systems.
- Generators are to be a source of powerhouse heating.
- Two overhead powerhouse cranes, with the capability to operate in tandem having a combined design capacity, when operated in tandem, to lift a fully assembled rotor.
- Elevator access to all levels of powerhouse.
- Dewatering and drainage systems complete with oil interception system.
- Permanent waste hydraulic and lubricating oil storage and handling system complete with a permanent centrifuge filtration system.
- Permanent hoist system required for each turbine pit.

<u>Generator Transformers and Switching</u>

- Four step-up transformers (unit voltage to 345 kV) located on powerhouse draft tube deck.
- Each unit will have a generator breaker.

<u>Muskrat Falls HVac Switchyard</u>

- Four 345 kV HVac cable sets to connect the high side of the step up transformers to the switchyard.
- Situated on the south side of the river on a level, fenced site.
- Concrete foundations and galvanized steel structures to support the electrical equipment and switchgear.
- Electrical layout of the switchyard is to be in accordance with the proposed single line diagram (SLD).

<u>HVac Overland Transmission - Muskrat Falls to Churchill Falls</u>

- Two 345 kV HVac overhead transmission lines to connect the Muskrat Falls switchyard to Gull Island and the Churchill Falls switchyard extension (distance = 263 km).
- Lines are to be carried on galvanized lattice steel towers, with self-supported angles and deadends, and guyed suspension towers.
- Line power capacity is to be 900 MW for each line, allowing for all load to be carried on a single circuit.
- 50-year reliability level return period of wind and ice loads.
- All lines to have overhead lightning protection via overhead ground wire (OHGW) with one being optical ground wire (OPGW) for the operations telecommunications system.
- Counterpoise installed from station to station.

<u>Churchill Falls HVac Switchyard Extension</u>

- To accommodate 2 X 345 kV HVac transmission lines from Muskrat Falls.
- To be an extension within the existing Churchill Falls (CF) Switchyard.

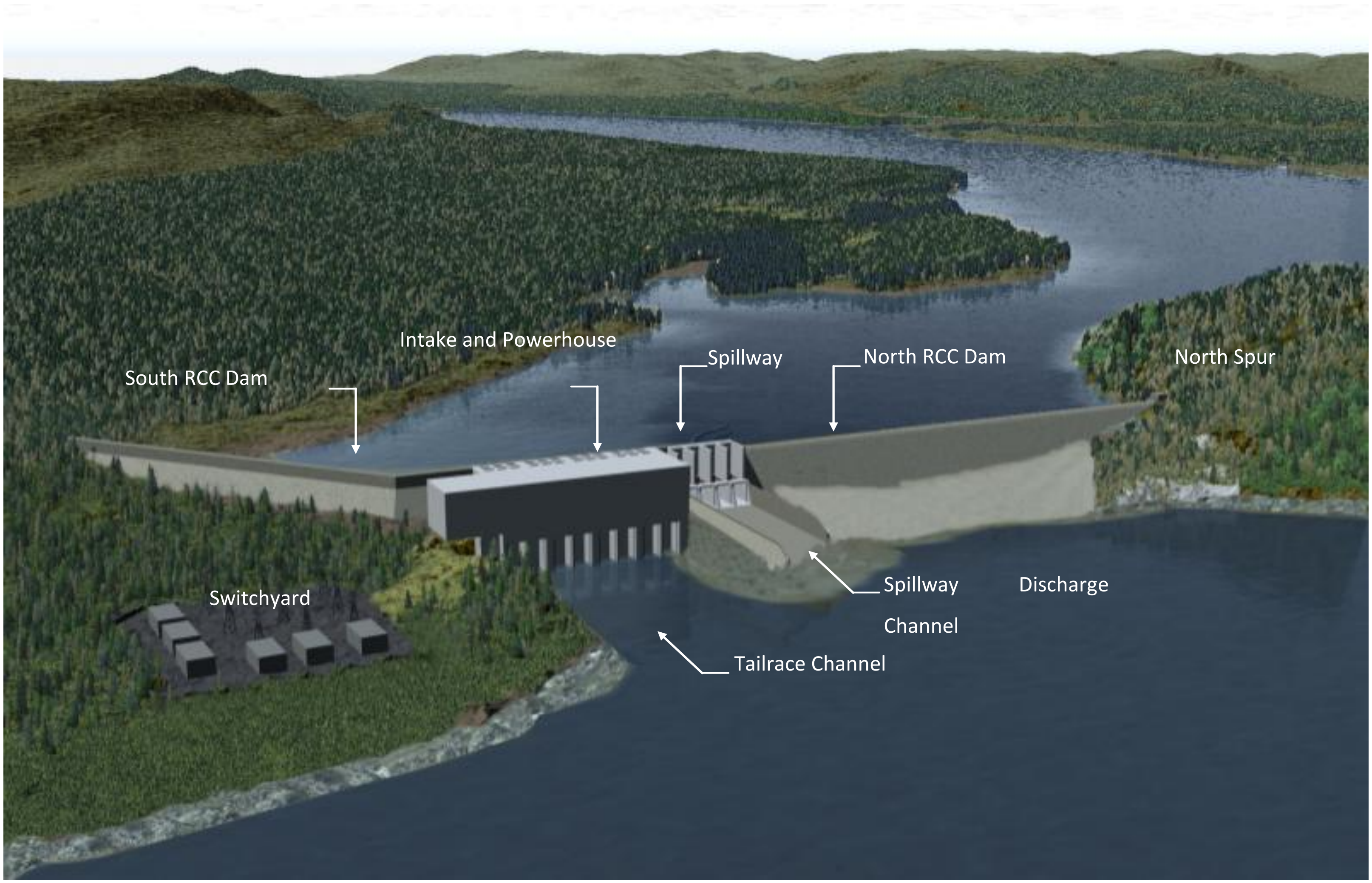
- Construction and operation not to adversely impact the existing CF operation.
- Concrete foundations and galvanized steel structures to support the electrical equipment and switchgear.

<u>Operations Telecommunication Systems</u>

- All permanent control, teleprotection, SCADA and voice circuits to have communication redundancy.

A conceptual drawing of the Muskrat Falls site is shown in Figure 5 on the following page.

1 **Figure 5: Conceptual Sketch of Muskrat Falls Generating Facility**



2.3.2 Labrador-Island Transmission Link

The key elements of the Basis of Design for the Labrador – Island Transmission Link can be broken down into project components as described in the following sections.

<u>HVac Connection from Muskrat Falls Switchyard to HVdc Converter Station</u>

- Two 345 kV HVac transmission lines to connect the Muskrat Falls switchyard to the 320 kV HVdc Converter Station.
- Each of the 345 kV HVac lines to have a designed power capacity of 900 MW.

<u>Muskrat Falls Converter Station</u>

- 900 MW, 320 kV bi-pole, Line Commutated Converter (LCC) Station capable of operating in mono-polar mode.
- Each pole rated at 450 MW with 100 percent overload protection for 10 minutes and 50 percent overload protection for continuous operation.
- Situated on the south side of the Churchill River on a level fenced site.
- Concrete foundations and galvanized steel structures to support the electrical equipment and switchgear.
- Mono-polar operation shall be supported by an electrode.

<u>Soldiers Pond Converter Station</u>

- 900 MW, 320 kV bi-pole, LCC Station capable of operating in mono-polar mode.
- Each pole rated at 450 MW with 100 percent overload protection for 10 minutes and 50 percent overload protection for continuous operation.
- Situated on the north side of the Soldiers Pond alternating current (ac) terminal station on the Avalon Peninsula on a level fenced site.
- Concrete foundations and galvanized steel structures to support the electrical equipment and switchgear.
- Mono-polar operation shall be supported by an electrode.

Electrode Line - Muskrat Falls to SOBI

- An overhead electrode line carrying 2 conductors – route to be selected within the same right of way (ROW) of the HVdc transmission line.
- Wood pole construction.
- 50-year reliability level return period of wind and ice loads.
- Electrode line will have provision for lightning protection.

Electrode - Labrador

- A shoreline pond electrode to be located on the Labrador side of the SOBI.
- Nominal rating of 450 MW with 100 percent overload protection for 10 minutes and 50 percent overload protection for continuous operation.

Electrode Line – Soldiers Pond to Conception Bay

- An electrode line carrying two conductors generally follows the existing transmission ROW from Soldiers Pond to Conception Bay.
- Wood pole construction.
- 50-year reliability level return period of wind and ice loads.
- Electrode line will have provision for lightning protection.

Electrode – Soldiers Pond

- A shoreline pond electrode to be located on the east side of Conception Bay.
- Nominal rating of 450 MW with 100 percent overload protection for 10 minutes and 50 percent overload protection for continuous operation.

HVdc Overland Transmission - Muskrat Falls to Soldiers Pond

- An HVdc overhead transmission line, ±320 kV bi-pole, to connect the Muskrat Falls converter station to the Labrador transition compound at the Strait of Belle Isle (distance = 380 km) and to connect the Northern Peninsula transition compound at the Strait of Belle Isle to the Soldiers Pond converter station (distance = 688 km).
- Line to carry both poles (single conductor per pole), and one OPGW.

- This segment of the HVdc line is to have a designed nominal power capacity of 900 MW; however, given the mono-polar operation criteria, each pole is to have a nominal rating of 450 MW with 100 percent overload capacity for 10 minutes and 50 percent overload capacity for continuous operation.
- Counterpoise installed from station to station.
- Towers are to be galvanized lattice steel, with self-supported angles and deadends, and guyed suspension towers.
- 50 year reliability level return period of wind and ice loads.
- Figure 6 illustrates the route for the HVdc transmission line.

<u>Strait of Belle Isle Cable Crossing</u>

- Two plus one spare 320 kV Mass Impregnated (MI) submarine cables to transmit power across the SOBI.
- Cable(s) for each pole to have a nominal rating of 450 MW with 100 percent overload capacity for 10 minutes and 50 percent overload capacity for continuous operation.
- The route for the submarine cable crossing to be designed to meet the transmission, protection, reliability, and design life requirements, and give consideration to technical and economic optimization.
- Cables shall be adequately protected along the entire length of the crossing as required. However, installation methodologies may be employed to mitigate damage from external environmental and man-made risks.
- Where discrete protection application is required, protection measures shall be designed to meet the transmission and reliability requirements.
- Cable protection methodology will employ proven technologies only, and may include tunnelling, rock placement, trenching, horizontal directional drilling (HDD) and concrete mattresses.

<u>Transition Compounds – Submarine Cable to Overhead Line</u>

- Situated on a level fenced site.
- Provision for cables and associated switching requirements.

- Concrete pads and steel structures to support the electrical equipment and switchgear.
- Overhead line to cable transition equipment.
- Switching, control, protection, monitoring and communication equipment.

Soldiers Pond Switchyard

- Situated on the north-east side of Soldiers Pond on a level, fenced site.
- Concrete foundations and galvanized steel structures to support the electrical equipment and switchgear.
- Electrical layout of the switchyard is to be in accordance with the proposed single line diagram (SLD).

Island System Upgrades

- Conversion of existing Holyrood Units 1 and 2 to synchronous condensers (note: Unit 3 has already been converted to a synchronous condenser).
- Two plus one spare 300 MVAR high inertia synchronous condensers at Soldiers Pond to maintain system performance.
- 230 kV and 138 kV circuit breaker replacements.

Operations Telecommunication Systems

- All permanent control, teleprotection, SCADA and voice circuits to have communication redundancy.

Figure 6 shows the transmission corridors for the Labrador – Island Transmission Link. Alternate routes are shown in Labrador and on the Northern Peninsula that were included in the EA project registration document.

1 **Figure 6: Muskrat Falls Project – Transmission Line Route**

3.0 Project Execution and Delivery Strategy

This section of the document provides an explanation of the Gateway Decision process and the Independent Project Review (IPR) carried out for DG2.

3.1 The Gateway Decision Process

Nalcor is using a construction industry accepted best practice staged gate delivery process to determine if, and how, the Lower Churchill Project should proceed. The Gateway Decision Process is a staged, or phased, decision gate process used to guide the prudent planning and execution of a large scale construction project from the identification of a business need through to operations and eventually decommissioning.

Phase I of the LCP has passed through Decision Gate 2. Prior to DG2, the focus was on selecting a design alternative that ensures the project can proceed on a cost effective and economic basis. However, there are still formal opportunities and checkpoints to revisit the feasibility of the project and discontinue work, if necessary. Proceeding through DG2 does not ensure projects will be sanctioned at Decision Gate 3 (DG3). It is at DG3 where sufficient engineering and other work has been completed which will enable a decision to be made on sanctioning the project.

Gateway Objectives

The Gateway Process has the following objectives:

- To provide a process to capture and utilize best value-adding potential.
- To provide a mechanism for Nalcor Energy to verify readiness to move from one phase to another in a systematic manner during the lifecycle of a project;
- To demonstrate that due diligence checks and balances are being applied during the execution of the Project; and
- To provide a means to pre-define "readiness" requirements for a project to progress from one project phase to the next.

Gateway Responsibilities

The owner of the Gateway Process, or Gatekeeper, is Nalcor Energy's CEO and President, with responsibility for the implementation and stewardship of the process delegated to the responsible Vice President. The Gatekeeper consults with the Nalcor Board of Directors and seeks Shareholder alignment and approval.

Within the Project, the phases are managed by cross-functional teams and are referred to as Gateway phases, while the gates (known as Decision Gates) are structured decision points at the end of each Gateway phase.

It is a core responsibility of the Project Management Team (PMT) to manage the phases between the gates, in order to optimize the time between gates.

Gateway Requirements

For each Decision Gate there are a number of gate requirements that have been agreed with the Gatekeeper. These gate requirements must be produced to an acceptable quality to facilitate efficient and effective decision making regarding the forward direction of the Project.

If some of the gate requirements are not complete at the Decision Gate then an evaluation is made to determine their criticality and if there is an acceptable plan in place to produce them in an appropriate timeframe. Certain gate requirements may be considered by the Gatekeeper, Board of Directors or the Shareholder as "showstoppers", which means that the Decision Gate cannot be passed until those gate requirements are fully satisfied. An example of a showstopper would be environmental approval to proceed with the construction.

The requirements for each Gateway phase are developed specifically for the Project and are developed with consideration of both standard project execution best practice, but more importantly with the consideration of the overall risk spectrum and tolerance for the Project. These have been designed to address all Project focus areas and encompass commercial arrangements, financing, regulatory, environment, aboriginal affairs, engineering and technical, project execution and stakeholder management.

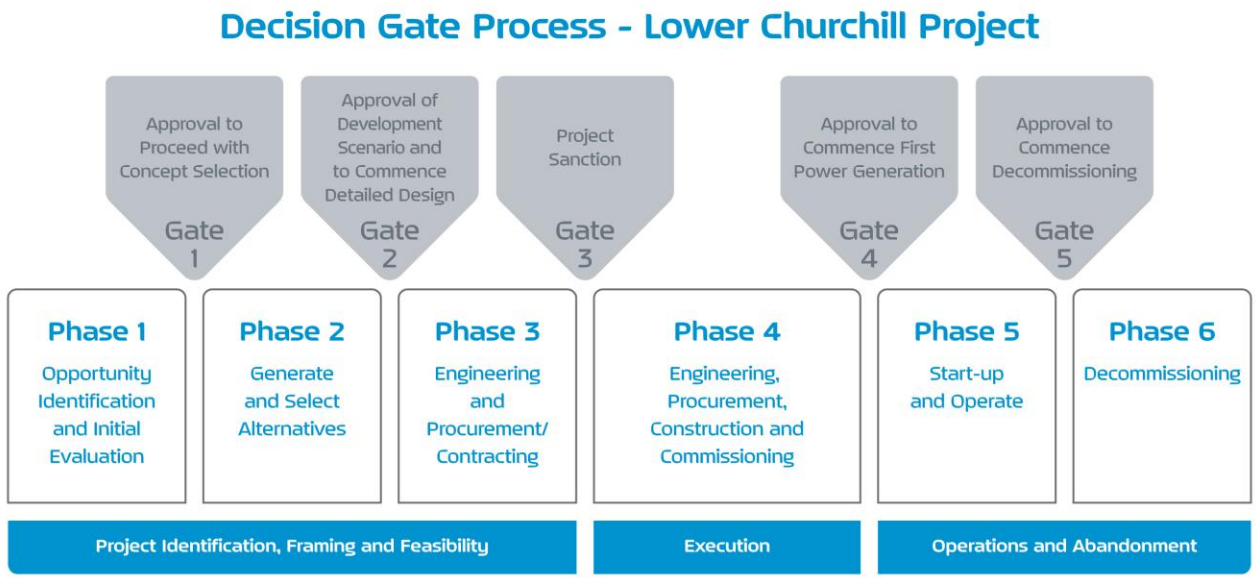
The use of formal Decision Gates facilitates decision-making by the Gatekeeper of the readiness of a project to move from one phase to the next, whereby the capital intensity of the phase increases. The Gatekeeper uses structured decision points, in consultation with Nalcor's Board of Directors and in agreement with the Shareholder, to make appropriate decisions whether to:

- hold all activity pending receipt of some final clarifications or supporting information is received;
- move to the next sequential phase; or
- stop/terminate all activity to proceed to the next project phase.

The Decision Gates contained within the Gateway Process are listed below and illustrated in Figure 7:

- Decision Gate 1 – Approval to Proceed with Concept Selection
- Decision Gate 2 – Approval of Development Scenario and to Commence Detailed Design
- Decision Gate 3 – Project Sanction
- Decision Gate 4 – Approval to Commence First Power Generation
- Decision Gate 5 – Approval to Commence Decommissioning

Figure 7: Project Gateway Process



The six (6) sequential Phases of the Gateway Process are:

Gateway Phase 1 – Opportunity Identification and Initial Evaluation

This phase includes the initial feasibility evaluation of the identified business opportunity, which in the case of the Project is the development of the hydropower potential presented by the Lower Churchill River. Gateway Phase 1 culminates at Decision Gate 1 when a decision is made on whether the Project is feasible and worth pursuing further.

Gateway Phase 2 – Generate and Select Alternatives

The objective of this Phase is to generate and evaluate a number of development options from which a preferred option to develop the business opportunity is selected. This Phase culminates at Decision Gate 2, when approval is sought for the recommended development option, the execution strategy, and initiation of detailed design. This phase involves aboriginal negotiations, environmental assessment processes, field work, power sales and access, financing strategy, advanced engineering studies, early construction planning, and economic analysis.

During Gateway Phase 2 there was a convergence of work by Nalcor's System Planning team and the LCP Project Team to ensure the selection of alternatives meets the future generation needs of the island and that Project team efforts were closely aligned. In this case it was the Generation Planning Issues 2010 July Update, which determined a requirement for additional generation capacity on the island of Newfoundland. Further engineering and economic analysis during Gateway Phase 2 ultimately determined Muskrat Falls and the Labrador- Island Transmission link to be the least cost alternative to meeting the island's long-term generation requirements.

Decision Gate 2 was of strategic importance to the Project Team as it signified that the development scenario, including phasing and sequencing had been confirmed, and that the Project Team is ready to move forward with further feasibility work, detailed engineering, procurement and contracting to prepare to commence early construction works following release from environmental assessment.

Gateway Phase 3 – Engineering and Procurement/Contracting

Gateway Phase 3 is focused on completing engineering and design, procurement planning, construction planning, and progressing environmental and regulatory approvals, and project management activities to a level sufficient to produce the cost and schedule estimates required for Decision Gate 3. Decision Gate 3 acts as the final check and confirmation that the investment decision is well founded.

The Decision Gate 3 cost and schedule estimates are a key input to verify the financial viability established at Decision Gate 2. The intended purpose of DG3 is to:

- verify the Decision Gate estimate and schedule;
- provide an increased level of confidence in outcomes required to facilitate the approval to move forward with Project Approval or Sanction; and
- establish the Project Budget.

During Gateway Phase 3, engineering will progress to a level of completeness required to award key construction and supply contracts required to maintain the overall project schedule and provide the level of cost and schedule certainty for passage through Decision Gate 3. Also during Phase 3, subject to environmental approval and approval of the necessary permits, some early activities such as access roads, construction power and site clearing may commence in advance of the full Project sanction at DG3. This early work may be essential to ensure critical path activities are carried out in a timely manner and future project milestones are not compromised. Such early works are typically not subject to Project sanction.

Gateway Phase 4 – Engineering, Procurement, Construction and Commissioning

This is the construction phase of the Project in which the hydroelectric facility and associated transmission are built and peak employment occurs. Concurrent to the start of early construction activities, the remaining engineering, procurement and contracting activities are completed. Also during this Phase, the systems required for first power must be fully commissioned, documented and handed over to the operator. This Gateway Phase ends at Decision Gate 4, which signifies a readiness to commence production of electricity.

Gateway Phase 5 – Start-up and Operate

During this phase, construction is substantially completed, electricity production occurs and transmission systems are energized. This includes facility maintenance and daily operation of the facilities.

Gateway Phase 6 – Decommissioning

A decision regarding the decommissioning of the hydroelectric development, when the facility has reached the end of its productive life occurs, at the beginning of this Gateway Phase, signified by Decision Gate 5. Following passage through this Decision Gate, decommissioning of the plant occurs.

3.2 Independent Project Reviews

To facilitate the Decision Gate assessment process, the Project Team utilizes Independent Project Review (IPR) Teams to provide independent assessments of the readiness of the Project to proceed at each Gate.

The Independent Project Reviews provide a degree of quality assurance required by the Gatekeeper for major decisions. The reviews are regarded as an opportunity to introduce external, constructive and holistic challenge to the Project Team, and provide assurance that the Project will deliver the required business results. The objectives of the IPR are to:

- provide external challenge to the Project team at each Decision Gate, to help assess the validity and robustness of the work done in key areas requiring focused attention and to assist in maximizing the value of the business opportunity;
- assess the suitability of the project plans and strategies; and
- appraise the readiness and justification of the project to proceed to the next Gateway Phase;

To ensure consistency and quality of approach, it is essential that personnel with the desired competencies and experience are appointed to lead the IPR. The following guidelines were adhered to when selecting the team leader:

- IPR Leader will be external to and independent of the project team;
- IPR Leader has experience in conducting similar types of reviews, preferably as the team leader; and
- IPR Leader has broad knowledge and experience covering Technical, Commercial, Operational, and Project Management issues.

IPR Team Members:

- The level, number and types of resources should be commensurate to the nature, size and significance of the review;
- The IPR Team should include a member of the project team who can act to support the review and provide guidance. The specific areas of competencies of the IPR team will vary between the different reviews depending on the focus of the decision being made. However, it is critical that the resources should cover the full range of

competencies including technical, environmental assessment, aboriginal, commercial, economic, operations, project management, and business issues;

- The IPR representatives should be senior personnel who have significant experience in their area of expertise; and
- Several of the IPR Team members should have experience from similar types of reviews.

IPR Results

A key finding of the IPR team was that "overall, the Project is ready for a Gate 2 decision, complies with best practice and is consistent with this project's specifics.[13]

In addition to the IPR, Nalcor also engaged Independent Project Analysis Inc. (IPA) to conduct a review using their proprietary "Project Evaluation System". IPA is a research and benchmarking firm, founded in 1987 devoted entirely to large capital projects. They are a recognized leader in project management research and consulting with a database of over 12,000 projects and over 300 organizations. A summary of IPA's review is provided in Exhibit 20[14] and included the following key findings:

The LCP is better prepared than a typical megaproject at this stage and has used several best practices including establishing a well developed team, developing clear objectives and closing project scope to achieve optimal project definition. IPA also concluded that the team is highly experienced and highly involved but also identified that there was a degree of misalignment on several project elements which presented risks and challenges going forward.

These risks and challenges in team functionality are quite common when establishing a Project team to execute a megaproject. Team building initiatives and organizational effectiveness measures have since been implemented and the identified risks and challenges have been effectively managed.

---

[13] Nalcor Energy, Gate 2 Independent Project Review. (Exhibit 22)
[14] IPA, Summary of IPA's Review of the Muskrat Falls Generation Project and the Island Link Transmission Project. (Exhibit 20)

4.0 Project Delivery Strategy

This section provides relevant information regarding the project delivery model and contract packaging. It defines the role of Nalcor as well as its contractors and how the relationships work. It also provides an overview of the construction approach to be used and a review of other management and control processes.

4.1 Selection of Project Delivery Model

The Project Delivery Strategy selected is the result of several years of technical definition, input from the power industry, consultants, and suppliers and numerous strategy workshops, all focused on the selection of the most appropriate project delivery model as well as the optimum contracting strategies to engineer, procure and construct this project.

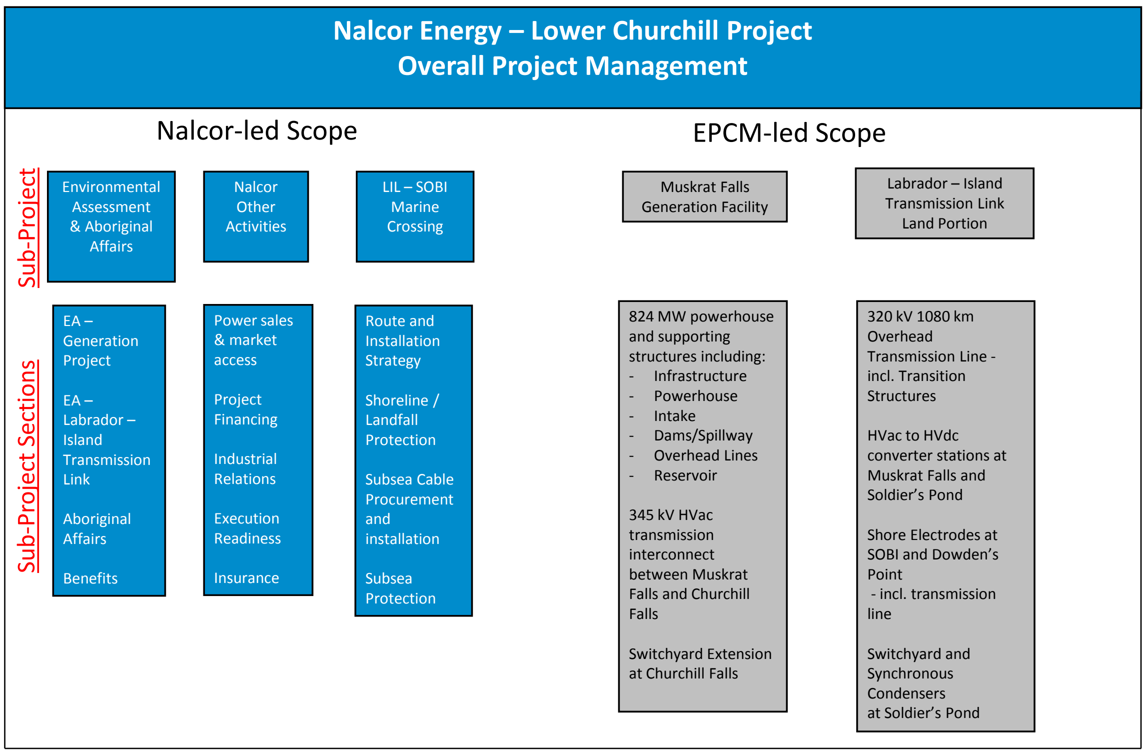
The Project Delivery Models considered for the Project Management included:

- EPC – In an Engineering, Procurement and Construction contracting model, the EPC contractor is responsible for all activities and assumes certain associated risks. These contracts frequently carry a cost premium and require greater definition of scope at the time of contract award.
- EPCM – In an Engineering, Procurement and Construction Management contracting model, the EPCM Contractor, acting as the Owner's representative, is responsible for the Engineering, Procurement and Construction Management of suppliers and contractors. The purchase orders and contracts placed by the EPCM Contractor on behalf of and using Nalcor's purchase order and contract formats may be in the form of lump sum, fixed price, unit rates or reimbursable contracts.
- Integrated Team – In this contract model, the Contractor provides the resources and systems required by the Owner. A contractor works within a fully integrated reimbursable format and becomes part of the Owner's Project Management Team.

As shown in Figure 8, an EPCM approach under Nalcor management has been selected for all project work scope other than the SOBI marine crossing, which remains directly under Nalcor Management.

The rationale for Nalcor retaining direct responsibility for the SOBI marine crossing scope was based upon the extensive experience in marine contracting and installation in Newfoundland and Labrador's offshore oil and gas industry. Nalcor will be contracting directly with the appropriate experienced contractors for this work.

Figure 8: Delivery Strategy



An EPCM delivery approach is well suited for Nalcor's needs because it provides schedule and cost advantages and an overarching system design and interface management across all aspects of the project. In addition, the approach allowed for sufficient de-risking of the design and procurement through an earlier start (Front End Loading), expert reviews, owner input, the addition of a world class designer and constructor, re-inforced emphasis on proven technology and time to define manageable interfaces.

4.2 Nalcor/EPCM Relationship

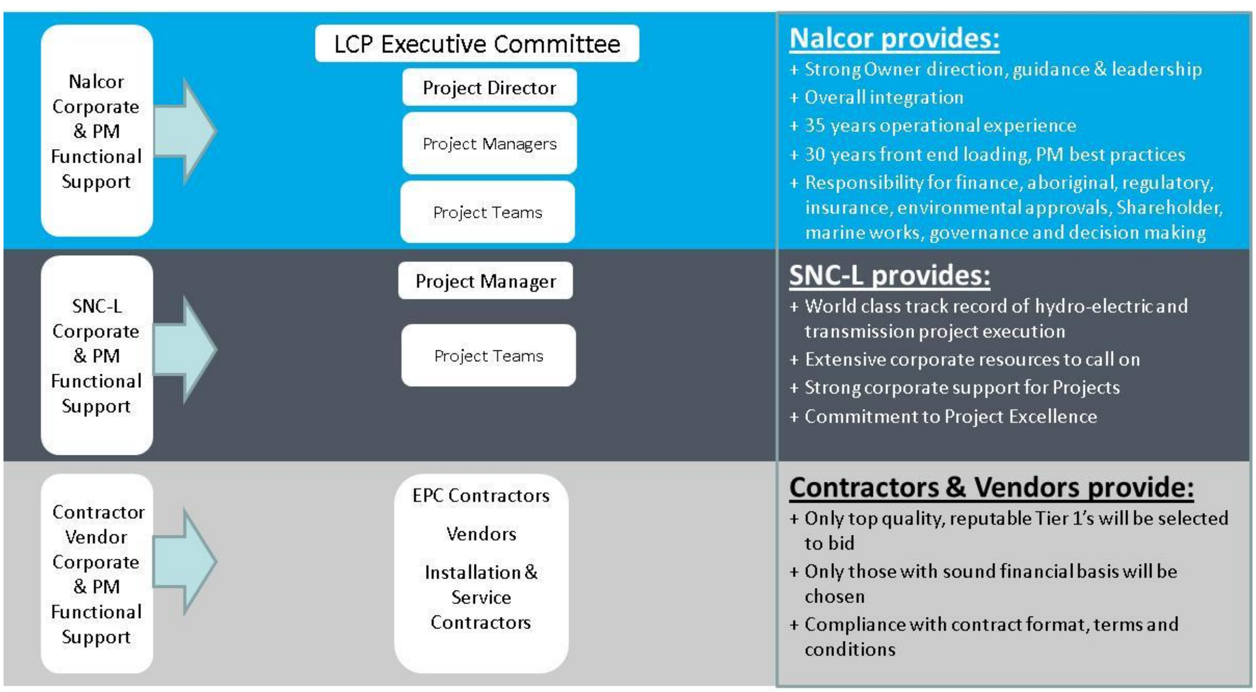
Nalcor and its EPCM Consultant will manage contract interfaces, resulting from the optimal balance between cost, execution risk and execution certainty. This will be accomplished through actions such as:

- Aligning interests of Nalcor and the EPCM Consultant;
- Ensuring an appropriately sized and skilled owner/EPCM team;
- Keeping interfaces to single points where practical; and
- Implementing a rigorous project-wide interface management process.

As contracting strategies are selected, they undergo review and validation prior to being finalized. This step is necessary as construction plans are modified and as market intelligence is gathered. Accordingly, adjustments to the contracting strategies may take place during the Gateway Phase 3 of the Project.

This relationship is further illustrated in Figure 9 below.

Figure 9: Organizational Structure Overview



4.2.1 Nalcor's Roles and Responsibilities

As typical for all projects executed under an EPCM Consultant approach, the role of Nalcor as Owner includes many overarching areas that are outside the expertise of the EPCM Consultants. The LCP PMT will be responsible for a significant number of strategic functions throughout the planning and execution phases of the Project, including:

- Establishing the Project master schedule and overall execution approach for the Project;
- Establishing the Project control budget;
- Establishing and maintaining agreements with outside authorities (e.g. government, stakeholders, etc.);
- Establishing and maintaining the Project Basis of Design;
- Overall design integrity;
- Recruitment and training of operations staff;
- Industrial (labour) relations and negotiation of Project labour agreement (Special Project Order);
- Project financing;
- Overall industrial benefits management and reporting;
- Finance, accounting, treasury, audit functions;
- Establishing Project-wide policies and protocols;
- Placement and management of the Project's insurance program;
- Consultations and agreements with Aboriginal groups, including ensuring all commitments are maintained;
- Environmental assessment and management of all related commitments;
- Overall Project-level risk management;
- Conducting Project-level audits;
- Overall Project progress management and reporting against Project cost and schedule baseline;
- Management of interfaces;

- Overall project change management; and
- Stakeholder relations and communications.

The coordination procedures forming part of the agreement with the EPCM consultants detail this working relationship and how Nalcor and the EPCM consultants will interface.

4.2.2 EPCM Consultant's Roles and Responsibilities

Consistent with traditional Engineering, Procurement and Construction Management (EPCM) contracts, the EPCM Consultant, under the guidance and leadership of the Nalcor Project Team, is responsible for the completion of all project engineering and detailed design, construction execution planning, procurement of permanent plant equipment, issue and management of all supply and construction contracts, and overall construction management for the Project (other than for the SOBI crossing), including custodian for the Project work sites, and Project completions. The actual construction contractors, either managed by the EPCM consultant or directly by Nalcor, will be responsible for the safe and successful execution of their work packages in accordance with their contracts and approved safety programs, while the suppliers are responsible for delivery of goods and services for the Project.

4.3 Contract Packaging

Each of the three project components – Muskrat Falls generating facility, the Muskrat Falls-Churchill Falls HVac transmission and the Labrador-Island Transmission Link - requires varied skill sets which are recognized and built into the formulation of defined work contract packages. Development of contract packages has been heavily focused on EPC and lump sum contracts. Where necessary, unit price type contracts are considered, with emphasis on establishing firm quantities prior to contract award. Other considerations include:

- The alignment of work packaging strategies with bidder resources and capabilities thus maximizing market competition;
- The optimization of work packaging with respect to interfaces;
- The need to focus on integration management and optimal risk allocation; and

- The need to meet Nalcor's benefits and Aboriginal obligations.

4.4 Construction Approach and Sequencing

This section provides an overview of the construction sequence for Muskrat Falls, the Labrador-Island Transmission link and SOBI.

The general approach to construction will be to optimize the number of contractors working on site in consideration of contractor capability, the number of interfaces created, and to accommodate market conditions. Individual contracts will be treated as sub-projects within the overall execution approach, with a sharing of common resources and infrastructure managed by the EPCM Consultant (e.g. accommodations, transportation services, fuel, etc.).

4.4.1 Muskrat Falls Generating Facility

The first item of importance to the construction program at Muskrat Falls is to establish site access. This will be done by constructing an access road along the south side of the river from Blackrock Bridge to the Muskrat Falls construction site. This road is approximately 18 km long, and it is estimated that it will take about three to four months to complete. However, it is possible to mobilize the construction equipment required for the initial works at the site on this road before it is fully brought up to the required standard.

Once access is gained to the construction site on the south side of the river, site infrastructure works can begin. This includes site roads, accommodations infrastructure and installation/erection of communications and construction power infrastructure, potable and sanitary water supplies, septic infrastructure, etc. The main site accommodations complex and associated infrastructure will be established in two phases – a starter camp to facilitate the initial works and a follow-on or full camp that will be required to support the main construction.

Once access has been gained to the south side, work can begin on the clearing operations for the reservoir on the south side. Clearing for the north side of the reservoir can begin earlier, utilizing access routes on the north side from the Trans-Labrador Highway.

Concurrent to the commencement of early works construction will be the commencement of right-of-way clearing for the Muskrat Falls to Churchill Falls HVac transmission line, with the first line scheduled to be completed by August 2014 and energized at 138 kV in order to provide construction power support. It will later be switched to operate at the rated voltage for first power.

The primary civil works for the facility will begin with the excavation (overburden and rock) for the spillway and the powerhouse, as well as the intake and tailrace areas near the powerhouse.

After excavation, stage 1 concreting can begin in the powerhouse, as well as the intake and spillway. At this time, some components will be required for the spillway and intake gates, as well as the turbines.

As this occurs, some civil works will also be taking place on the North Spur to stabilize the spur and ensure its viability as a natural dam, holding back the reservoir. This work is not expected to be critical and can be performed during the prime construction months over several years, with the only constraints being access to the spur, and ensuring that all of the work is completed prior to filling of the reservoir (impoundment).

After the powerhouse stage 1 concreting, the powerhouse superstructure will be built, and the crane erected. The superstructure will start from the assembly hall, and proceed through the powerhouse. At the same time, the unit assembly will proceed. As the unit erection will require the use of the assembly hall and the powerhouse crane, the superstructure and the turbine build sequence are closely linked.

Once the spillway gates are installed, stage 1 filling of the reservoir (diversion head pond) would commence, requiring the removal of the "plug" at the intake and outlet of the spillway. This is required so that the cofferdam can be placed in the river to facilitate the construction of the north dam. In doing this the course of the river is changed to push it through the spillway. The Stage 1 diversion head pond raises the river level to about elevation 24 m.

After the cofferdams are constructed, the foundation works for the north dam can begin. As this work is progressing, the south dam construction can take place. It is possible to construct this dam earlier, but doing so will likely not gain any schedule advantage, and may come at a slight cost increase, as both dams would be constructed of Roller Compacted Concrete (RCC) and would be carried out by the same contractor. Early construction would require earlier or double mobilizations, potentially adding to project costs.

The north dam will be built after the north dam foundations are complete. Two construction seasons are expected to be required for the work on the dams, including the cofferdams, foundations preparation and dam construction.

As this work progresses the switchyards at Muskrat Falls and switchyard modifications at Churchill Falls will begin.

At about this time the reservoir clearing will be nearing completion, and decommissioning will begin. This decommissioning involves removing any infrastructure created to support the reservoir clearing and habitat enhancement operations (temporary campsites that were not already decommissioned, road surface modification to prevent unintended usage and to promote re-growth, etc.).

During this time, turbine unit assembly will be at an advanced stage, leading to the commissioning of the turbine units in sequence, with power being generated from each unit in turn. This requires the removal of the tailrace "plug" that was left in place to prevent flooding of the powerhouse, and completion of impoundment to the Full Supply Level (FSL).

In sequence with the first power generation at Muskrat Falls, it is necessary to have the transmission system in place from Muskrat Falls to Churchill Falls, along with the switchyards at Muskrat Falls and Churchill Falls. While each component would be commissioned individually, the entire system will be commissioned and synchronized during this commissioning phase.

4.4.2 Labrador – Island Transmission Link

Overhead transmission lines are to be installed from the Muskrat Falls generating facility to the Strait of Belle Isle. The lines will leave the Strait of Belle Isle on the island side and travel to Soldiers Pond on the northeast Avalon Peninsula.

The overhead transmission system will consist of two conductors and an overhead ground wire connected at the top, the function of which will be to shield the other infrastructure from possible lightning strikes. The overhead ground wire will be equipped with a fiber optic cable (OPGW) to fulfill the communication requirements between the converter stations. All lines along the transmission route will be supported by galvanized steel towers. The spacing of the transmission towers will be based on topographic, meteorological and other environmental factors.

A 2 km wide transmission corridor has been chosen for planning of the HVdc transmission route. This corridor contains the existing transmission route along with several alternative segments. Once the actual transmission route is selected, a right-of-way of approximately 60 m will be cleared. The right-of-way width is site specific and may range from less than 60 m and up to 80 m, depending on the particular area. Detailed routing of the HVdc transmission lines will be determined by a comprehensive route selection process based on technical and environmental considerations.

The Muskrat Falls and Soldiers Pond converter stations are to be built on concrete foundations over a levelled gravel surface yard and grounding grid. Galvanized steel structures will be erected to support the switchgear and other electrical equipment. A valve hall will also be constructed at each converter station site to house the converter equipment.

Existing transmission lines are to be connected to the Soldiers Pond converter station to allow the transmission of electricity to the Island grid. To ensure proper integration of the HVdc system into the Island grid several modifications may need to be implemented, including the installation of transmission line compensation equipment, synchronous condensers, circuit breakers, disconnect switches and other instrumentation, as well as conductor replacement.

The converter station engineering and construction phases are scheduled for an approximate duration of four years. The first and second years will include design, procurement and manufacturing of specialized equipment. The third and fourth years will encompass the construction of the facilities, including site preparation, outfitting, supporting infrastructure installation, and testing and commissioning.

Shoreline pond electrodes will be required in the case of a pole failure. These electrodes are connected to the HVdc converter stations located in Labrador and on the island and are necessary to complete the electrical circuit to allow for the single pole to continue in operation providing fifty percent of the power.

Two low voltage conductors will connect the converter stations to the shore electrodes. The conductors will be carried on 10 m to 12 m high wood poles with approximately 60 m spacing. Cables will then attach to each individual electrode element.

Installation of a wood pole line for the electrodes, depending upon the amount of clearing along the transmission right-of-way, is scheduled for approximately 12 months. Construction of the electrode site, including electrode installation, take-off structure construction, associated infrastructure installation and breakwater construction is scheduled for an approximate duration of eight months.

4.4.3 SOBI Marine Crossing

The following section details the process for the cable installation on a conceptual design basis. There will be three submarine cables installed with each protected by a dedicated rock berm to protect against dropped objects and fishing gear damage. Only two cables are required with the third cable being an installed spare. Details relevant to the SOBI crossing are contained in Exhibit CE-44 Rev. 1[15], which is the definitive source of the SOBI marine crossing design and construction approach.

Routing

The cable corridor in which the conceptual cable route is to be defined is as shown in Figure 10. This corridor takes into account the landfall and protection methods discussed in this report. The estimated length of the each of the three SOBI submarine cables is approximately 36 km with roughly 32 km on the sea floor. The routing for each cable will be within a 500 m corridor. Detailed cable spacing and routing will be carried out in Gateway Phase 3. The horizontal directional drilled bore hole will bring each of the three submarine cables to a point which is below the greatest draft of icebergs in that area and away from the shoreline to protect against pack ice.

Figure 10: SOBI Conceptual Design Routing

[15] Nalcor Energy, SOBI Marine Crossing Phase 2 Conceptual Design. (Exhibit CE-44 Rev. 1)

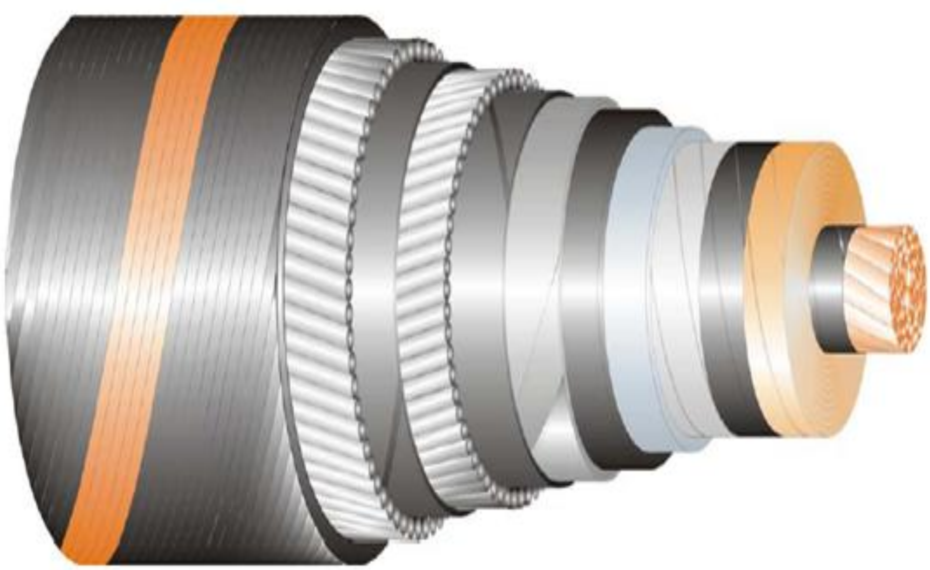
<u>Cables</u>

The current conceptual cable design includes:

- Single Core (Copper or Aluminum conductor, pending detailed design)
- Mass impregnated paper insulated cables
- Double wire armour (DWA) in a counter-helical fashion to maximize pulling tension and provide rock armouring. Armour will consist of steel wire coated in Bitumen
- Outer serving will consist of two layers of polypropylene yarn or high density polyethylene as needed

An illustrative schematic of a typical submarine cable is provided in Figure 11.

Figure 11: Illustrative Schematic of a Submarine Cable



Transition Compounds 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 EPCM Consultant. It is envisaged at this time that the cables will be pulled to shore then land trenched to the location of the transition compound. The compound location is not yet defined but will most likely be located within 1000 m of each shoreline. The compound will house the cable terminations, as well as any switchgear that is required for system operation. Actual footprint and height of the compounds will be determined by the EPCM Consultant and are based on isolation requirements and installation techniques of the terminations. The cables will enter the transition compound through a foundation penetration.

End terminations for each cable will reside inside the Transition Compound, and will be inclusive of the stand, insulator, and ancillary equipment. All equipment associated with the end termination will be supplied and installed as part of the cable supply contract.

Landfall - HDD

For both shore approaches, Horizontal Directional Drilling (HDD) will be utilized to protect the cables and will run from the shore to a point on the seafloor within the designated target zone. This point will be approximately 2 km from the shoreline, however it may become shorter or longer pending detailed design. The depth of water that the HDD will exit to the sea bed will be at least 75 m. The HDD solution will provide steel-lined boreholes for each shore approach. A footprint of approximately 2-6 acres is required on both Newfoundland and Labrador sides of the Strait to safely execute the HDD scope.

Cable Installation

The current philosophy is that the cable installation will include a subsea joint to allow for pull-in without laying an over length of cable on the seafloor. This means that the cable vessel will lay each cable across the sea bed and then each cable will be jointed at either end to the cable which is pulled in through the horizontally drilled steel-lined bore holes.

Deepwater Zones – Rock Placement

For the deepwater zones, rock placement will be utilized to protect the cables between the HDD seafloor piercing on the Newfoundland side and the HDD seafloor piercing on the

Labrador side. Each cable will be protected by a dedicated rock berm, which will be 0.5 - 1.5 m high with the potential for higher areas if additional protection is required. Preliminary studies suggest that the rock berm will have a nominal side slope ratio of 1:4 (rise:run) and will be 8-12 m wide at the base. The current rock has been based on an 8" D minus (maximum graded target size will be 8 inch diameter).

Icebergs and Ice Scouring

As icebergs often travel down the coast of Labrador, it is important to understand the extensive measures that have been taken to study the potential for ice contact and mitigate the risks associated with it. To assess the risk of an iceberg impact on the cables, Nalcor enlisted C-CORE to perform a Monte Carlo analysis on the submarine cable route[16].

C-CORE is a multi-disciplinary research and development organization with world leading capability in remote sensing, ice engineering and geotechnical engineering. It has extensive experience in ice prone regions in Newfoundland and Labrador and around the world.

C-CORE's iceberg risk analysis model has included in-depth research of ice in the Straits area. This includes detailed analysis of key criteria including bathymetry, iceberg size distribution, iceberg size/mass/draft, relationships, deterioration rates, draft changes and drift characteristics. The iceberg contact model is a Monte Carlo simulation that models the distribution of iceberg groundings and potential contact incidences.

A major finding from the analysis is the presence of the "bathymetric shield", a nominally 60 m shelf that protects the submarine cable route, and extends for nominally 50 km. This bathymetric shield shelters the cables from large iceberg impacts. Portions of the bathymetric shield are both deeper and shallower than 60 m.

As part of the C-CORE analysis, icebergs of a deeper draft than the bathymetric shield were modeled to roll in over the shelf, for varying periods between rolling (known as the rolling rate). The concept of rolling is a phenomenon where an iceberg grounds, melts and breaks

[16] C-CORE, Iceberg Risk to Subsea Cables in Strait of Belle Isle. (Exhibit 35)

apart changing the center of gravity, and then rolls to become ungrounded. In order for an iceberg such as this to scour in our area of interest, an increase in draft must occur subsequent to rolling – an extremely low probability event. For a probable rolling rate, the lowest probability of contact at 70 m water depth along the route is one in 1000 years. In excess of the 70 m water depth, the probability of contact is nominally zero.

To protect the cables from icebergs, given the bathymetric shield, Horizontal Directional Drilling (HDD) was implemented. HDD technology allows the cables to be routed safely in a conduit drilled in rock below the seabed to a water depth of nominally 70 m on the Newfoundland side (Shoal Cove) and 80 m on the Labrador side (Forteau Point). For the 30 km between the subsea hole piercing locations, the cables are placed on the seafloor in a route that maintains a water depth in excess of 80 m for the majority of the crossing, hence, safely sheltered from potential iceberg contact.

Figure 12: SOBI Iceberg and Pack Ice Protection

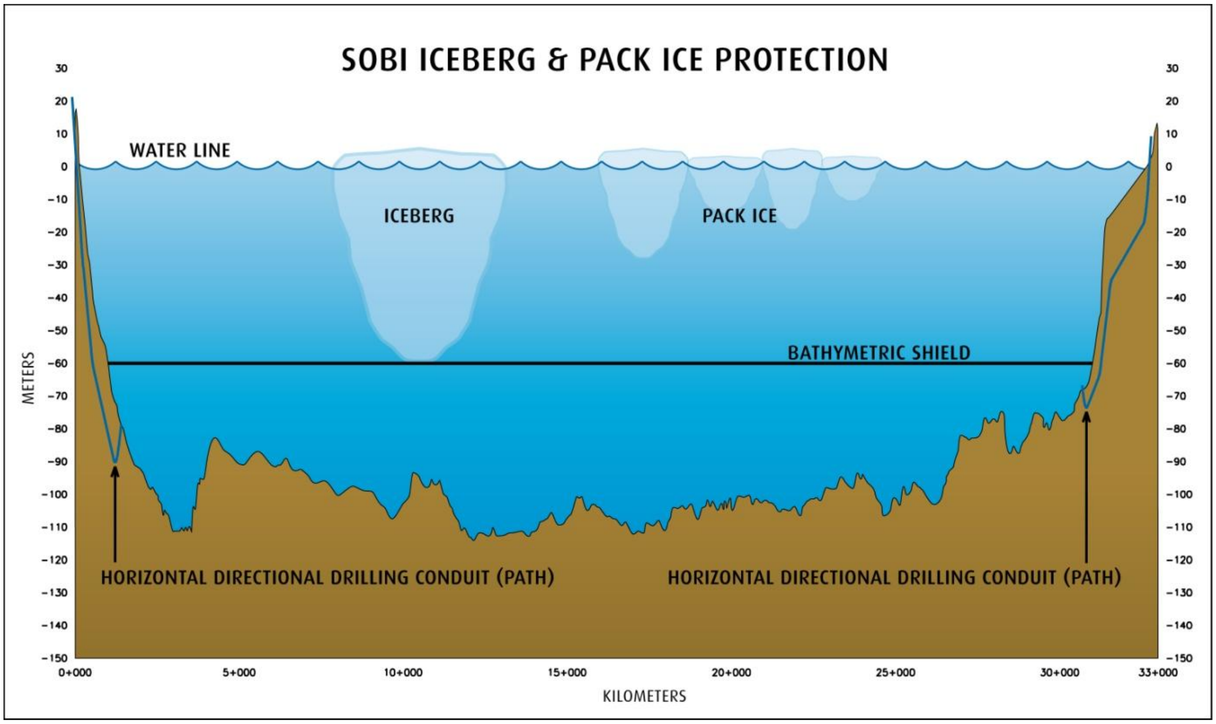


Figure 12 illustrates the iceberg and pack ice risk mitigation measures considered in the design. The bathymetric shield forms a natural barrier to icebergs with a draft greater than 60 m from entering the SOBI cable crossing zone. The HDD bore holes bring the cables into the seabed well below the draft of icebergs and protect the cables at the shoreline from pack ice. The subsea cables will follow the natural protected contours of the seabed to depths of up to 120 m as they exit the HDD boreholes as shown.

4.5 Other Management Processes

4.5.1 Quality Management

The Lower Churchill Project's approach to Quality is structured upon the Plan-Do-Check-Act model of continual improvement and the eight management principles set out in ISO 9000 standards, including: customer focus; leadership; involvement of people; process approach; system approach to management; continual improvement; factual approach to decision making; and mutually beneficial supplier relationships.

These principles form the basis upon which the PMT establishes and measures Quality performance in all of Nalcor's activities and the activities of its EPCM consultant, contractors and suppliers.

4.5.2 Health and Safety Management

The Lower Churchill Project undertakes its business in such a way as to minimize the risks of injury or ill health to people and damage to property or the environment. Nalcor believes sound health and safety performance is fundamental to successful business performance. It is therefore the PMT's requirement and expectation that everyone associated with the Project shall play their part in the implementation of its occupational health and safety management strategy, performing at the highest possible levels, and foster continuous improvement in the areas of health and safety.

The Lower Churchill Project's health and safety management system for the Project will be consistent with the principles of ISO 18001 and will be based upon Nalcor's existing corporate health and safety management system.

4.5.3 Environmental and Regulatory Compliance Management

Nalcor has made a commitment that the Project will be designed and constructed in accordance with Nalcor Energy's environmental policy and guiding principles. This provides the strategic direction of how Nalcor's Environmental Management System (EMS) and associated Corporate EMS Targets will be adhered to by the Project Team, EPCM Consultant, and EPC/EPCI contractors during the engineering and construction of the Project.

The LCP Engineering Manager has the responsibility for developing design philosophies that reflect Nalcor Energy's environmental policy, and to ensure consistency between the sub-Projects for incorporating environmental management into the design of Project components. The Engineering Manager will communicate these requirements to the EPCM Consultant who shall incorporate the requirements into the overall facility design and construction execution program, including individual construction contracts. The LCPs design and integrity function will verify that these environmental requirements are adhered to by the EPCM Consultant during the review and acceptance of all Project specifications, drawings and other technical documents.

4.5.4 Performance Management

The Lower Churchill Project will implement an overall performance management program in order to effectively and efficiently monitor and manage overall progress as well as make timely and efficient decisions. This performance management program will include a number of key metrics that are definable, measurable and able to be reported monthly. Table 1 lists some of the envisioned key metrics for the Project during Gateway Phase 3. Project Controls will be responsible for stewarding the reporting of these Key Metrics.

Table 1: Key Performance Indicators for Gateway Phase 3

Category	Key Metric	Basis	Target
Health, Safety and Environment	All Injury Frequency Rate (AIFR)	(Number of Loss Time Incidents + Medical Aids X 200,000 hrs worked) ÷ Total Hrs worked to date	0
	Total Reportable Incident Frequency (TRIFR) Year to Date	(Number of Loss Time Incidents + Medical Aids + Restricted Work Cases 200,000) ÷ Total Hrs worked to date	<1.0
	Environmental Releases	Numbers of releases	0
	Leading / Lagging Ratio	Number of Leading Indicators ÷ Number of Lagging Indicators (as reported in SWOP Database)	350:1
Organizational Effectiveness	LCP PMT Mobilization	Actual FTE (Full Time Equivalents) against plan DG2 MFL	1.0
	EPCM Mobilization	Actual FTE (Full Time Equivalents) against plan Stage 2 MFL	1.0

Category	Key Metric	Basis	Target
	EPCM Key Personnel Not Filled	Number	0
	Recruitment and Retention	# of departures / Total # FTE	<5%
	Overtime Usage	O/T Hours / Regular Hours	<10%
Progress	Readiness for DG3	On Target for DG3 Decision Support Package for December 2011	
	Overall EPCM Progress	Actual / Plan (against Stage 2 Project Control Schedule - PCS)	>1.0
	Engineering Deliverables Issued For Use	Actual vs. Plan # of Documents	>1.0
	RFP's Issued	Number	
	PO's / Contracts Awarded	Actual vs. Plan (against Stage 2 PCS)	
	Key Risks	Number of Key Risks Closed During Period	
	EPCM Mgmt Plans	Deliverables in Place	All
Cost Performance	Commitments	Total value of commitments against plan	No variance
	Incurred Cost	Total incurred cost against plan	No variance
	Project Changes	• Quantity of Deviation Alert Notices • Quantity and Value of Project Change Notices	-
	Contingency Usage	Contingency Drawdown for Project Changes	
	Aged Invoices	Number of invoices not paid within contract period due to information shortfall	0

4.6 Management and Control

The Lower Churchill Project follows numerous processes and procedures to execute work. This section outlines the key areas of management and control for the Project.

4.6.1 Financial Control

The Project will have designated functions including Project Controls, Finance and Supply Chain Management who will work together and oversee financial control of the Project.

Financial control is exercised in three distinct forms, namely Authorization, Commitment and Verification.

<u>Financial Authorizations</u>

Authorization begins with the approval by the Nalcor Energy Board of Directors of either a pre-sanction Authorization for Expenditure (AFE) or Master AFE for the Project Component and related budget. Subsequent changes are governed through management of change procedures.

In the case of the LCP, the Project Director with Project Managers will delegate authorization authority to budget holders, as required to execute the Project.

Financial Commitment

For all goods or services to be acquired by the LCP, a financial commitment via a commercial contract between the LCP and the supplier or service provider is required. The raising of financial commitments creates a financial obligation on Nalcor and must be supported by and within the scope of a properly approved requisition.

The terms and conditions, scope, price and other relevant matters are recorded formally by Contracts, Purchase Orders (PO's), Work Task Orders (WTO's), Variation Orders, or amendments.

Financial Verification

Verification takes places upon receipt of a third party charge and includes both financial and technical verification. Financial verification occurs by the budget holder, with sufficient financial authorization that the invoice is in compliance with the related financial commitment document. Technical verification includes verifying quantities, quality and overall work progress or milestone achievement as claimed in the invoice.

An overview of the financial control structure is contained in Figure 13, while Figure 14 provides a representation of the overall cost control process from authorization through to verification for the Project.

1 **Figure 13: Financial Control Structure**

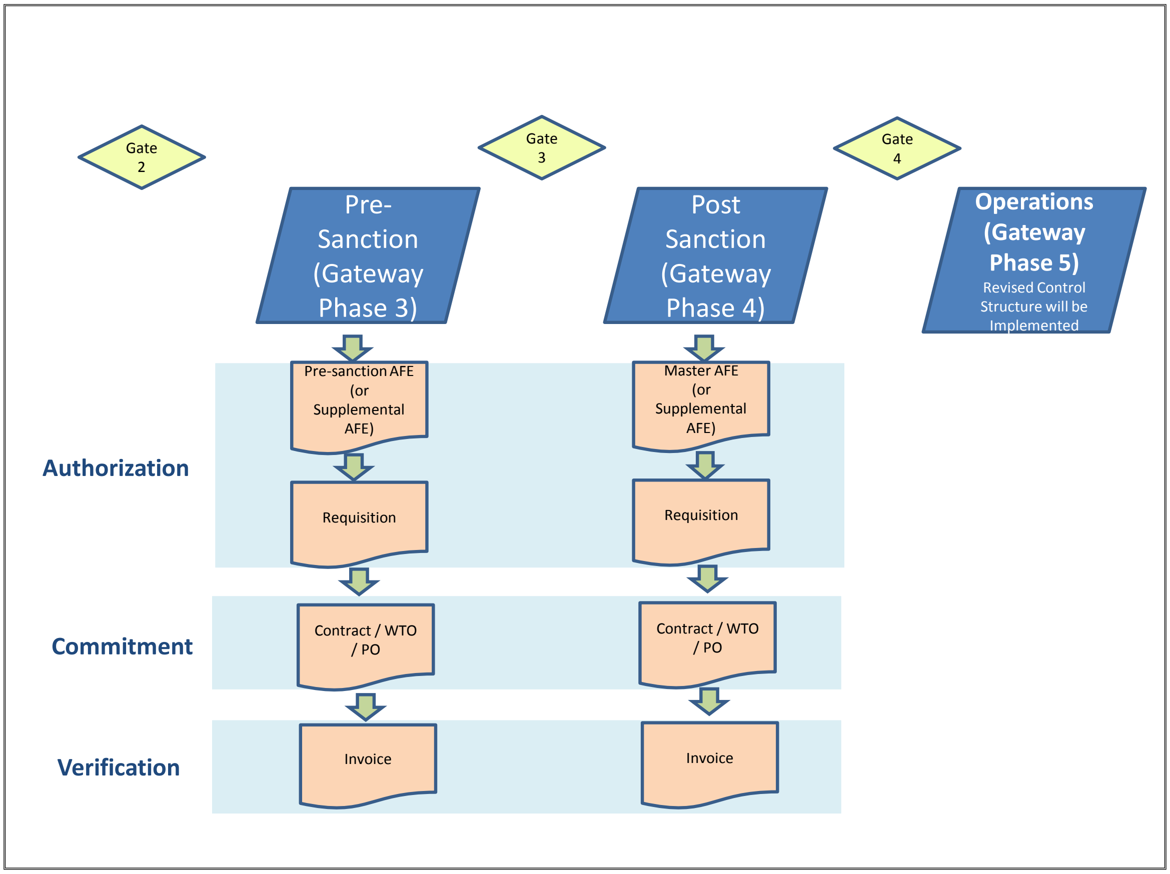
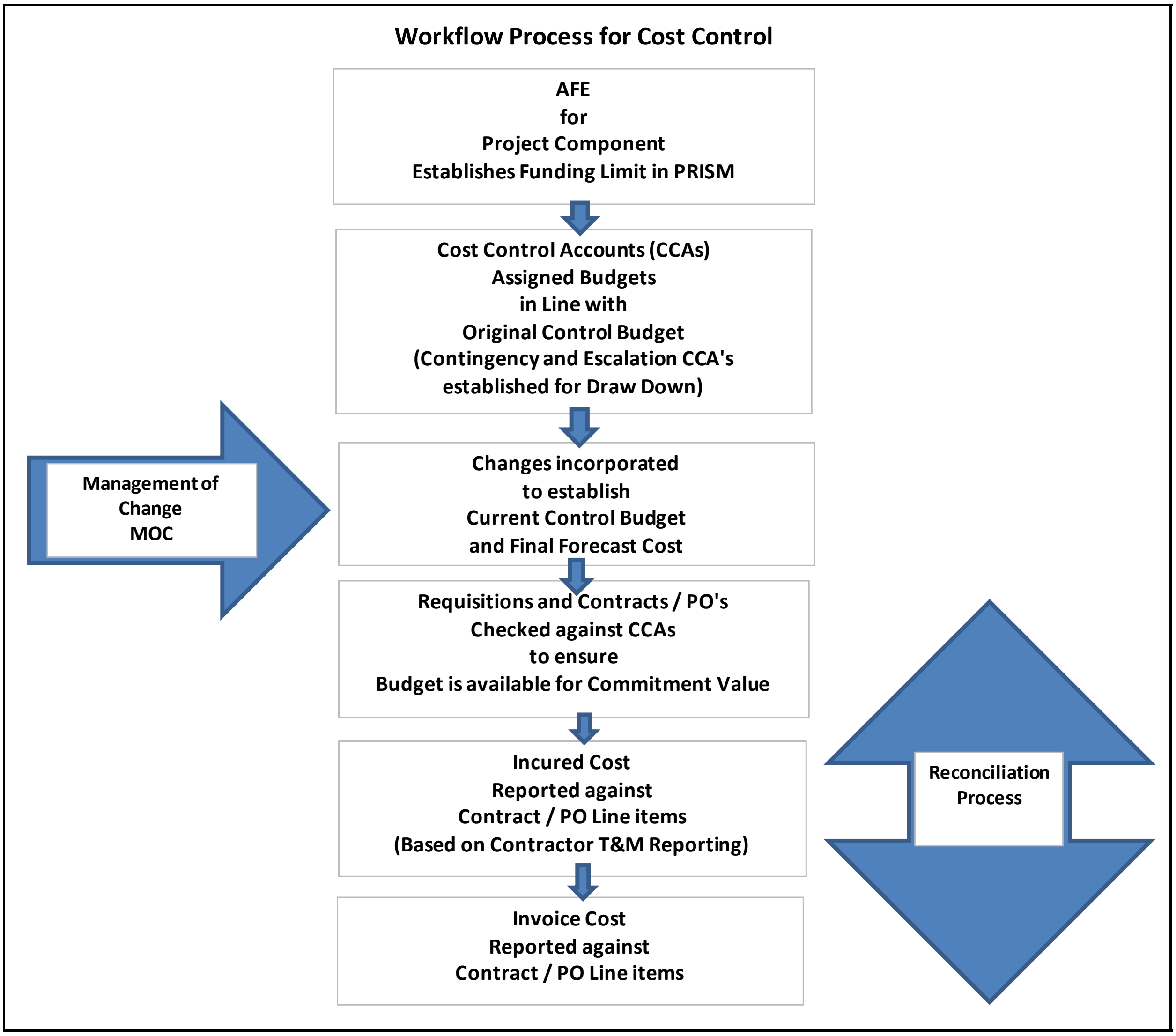


Figure 14: Workflow Process for Cost Control



4.6.2 Project Controls

The Lower Churchill Project has adopted a philosophy of having a strong Owner's project control team to support the Project and Area Managers in delivering their scopes of work while meeting cost and schedule targets.

To this effect, the Project Control team will assume the lead role in the consolidation of information and the co-ordination of the planning and scheduling, cost estimating, and cost control. They will provide the PMT with critical decision-making information in a timely manner by establishing appropriate levels of monitoring systems to ensure that control information is clearly defined and that roles and responsibilities of all participants are understood.

The project control philosophy or approach for the LCP is rooted in the following guiding principles:

- Scope, cost and time (schedule) are intricately linked and therefore must be holistically managed as one;
- Project control is a line management responsibility and not the responsibility of the Project Controls team. The Project Controls team provides the data needed to control the Project;
- One of the keys to an effective project control system is the quality of the information it uses and how that information flows. Good project information is wasted if it is not communicated quickly, correctly and consistently; and
- Exercise control at an optimum level – strike the right balance between the levels of detail to which stewardship is being performed and the ability to provide effective project control as an owner.

The EPCM Consultant and all other contractors shall be responsible for project control within the scope of their agreements, while LCP's Project Controls will actively review and validate critical information to provide the PMT with timely and critical information for decision making.

4.6.3 Management of Change

To function effectively, a Project Team must understand the basics of change management and have a management of change plan that establishes the methods and processes to be used for the project team to effectively identify, screen and incorporate changes to the baseline, including project delivery model. By adopting a disciplined approach to managing potential changes, negative impacts to project goals and objectives are minimized and positive opportunities can be realized.

Management of change provides a formal process to:

- Identify potential changes and the conditions that generate them;
- Identify high level contingency plans or responses to potential changes;
- Assess the need to adopt the potential changes;
- Evaluate the impacts of the potential change to the Project baseline;
- Ensure health, safety, environment, operability and maintainability requirements are considered as part of the evaluation of potential change;
- Approve/accept the potential change by all stakeholders;
- Implement action plans to address the change; and
- Document lessons learned with respect to the change.

The Project's Management of Change (MoC) system ensures project changes to applicable documents and processes are identified, evaluated, approved, documented, and implemented properly. This system describes the areas subject to change, the procedures to be used and maintained, and the roles, responsibilities, and approval limits for change management.

The management of change system is a LCP system for controlling project scope and ensuring that project changes are reviewed and approved at the appropriate organizational level. In general, approval of a project change follows a hierarchal process, with those changes having more significant cost and schedule implications, requiring higher level of approval within Nalcor's organization. In addition project changes that alter the Project's boundaries, objectives, key philosophies, or delivery approach must be approved by the Project's Gatekeeper.

The Management of Change process is applicable to all changes that have the potential to impact the Project scope, cost and schedule baseline, including changes to the Project's delivery method or execution approach. This includes engineering change as well as contract change facilitated through the use of Variation Orders.

Management of change is a shared responsibility between the PMT, the EPCM Consultant, the construction and installation contractors and the material and equipment vendors and suppliers working on the Project. Consultant, contractor and supplier change MoC processes will feed into the overarching Project MoC process. All change management requirements for contractors will be specified in the contract.

Detailed engineering and design for the Project will be undertaken by various Consultants and contractors, depending on the execution plan for the sub-project (e.g. SOBI Crossing), rather than directly by LCP itself. It is planned that the detailed engineering change management procedures (e.g. redline mark-ups, changed design codes and standards, field request for information, etc.) of these entities will be used to support the effective management of engineering and design change embedded within this Project MoC Plan as detailed in the respective contract coordination procedures.

4.7 Risk Management

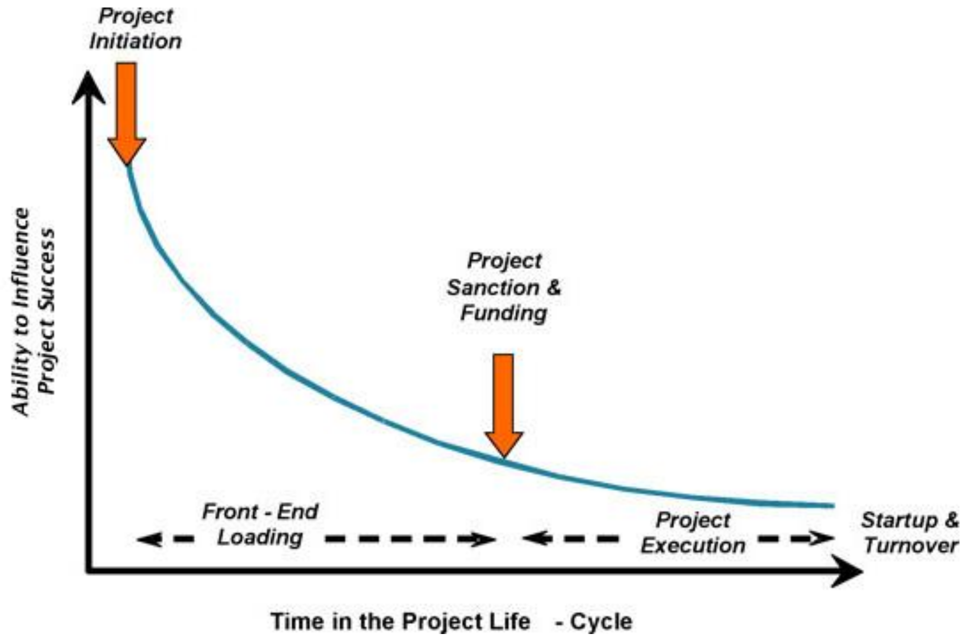
This section describes how Nalcor identifies risks as well as its philosophy for managing risk. It explains the work Nalcor has done with external consultants to further refine its risk management procedures. Portions of this section are extracted from Nalcor Exhibit CE-52[17].

Risk management is a critical governance structure for Nalcor. Specific project-level risk management processes, tools and resources have been implemented for the Project underneath the umbrella of Nalcor's corporate Enterprise Risk Management program.

Consistent with the "Project Influence Curve" shown in Figure 15, Nalcor has made extensive efforts in the early planning phases to identify, evaluate and implement opportunities to capture and maximize value that can be extracted from the Project. Nalcor believes that early risk (both opportunity and threats) planning is the key driving factor in increasing the predictability of the underlying business case for the Project, and has taken extensive steps to ensure the application of best practice for risk planning.

[17] Nalcor Energy, Technical Note – Strategic Risk Analysis and Mitigation. (Exhibit CE-52)

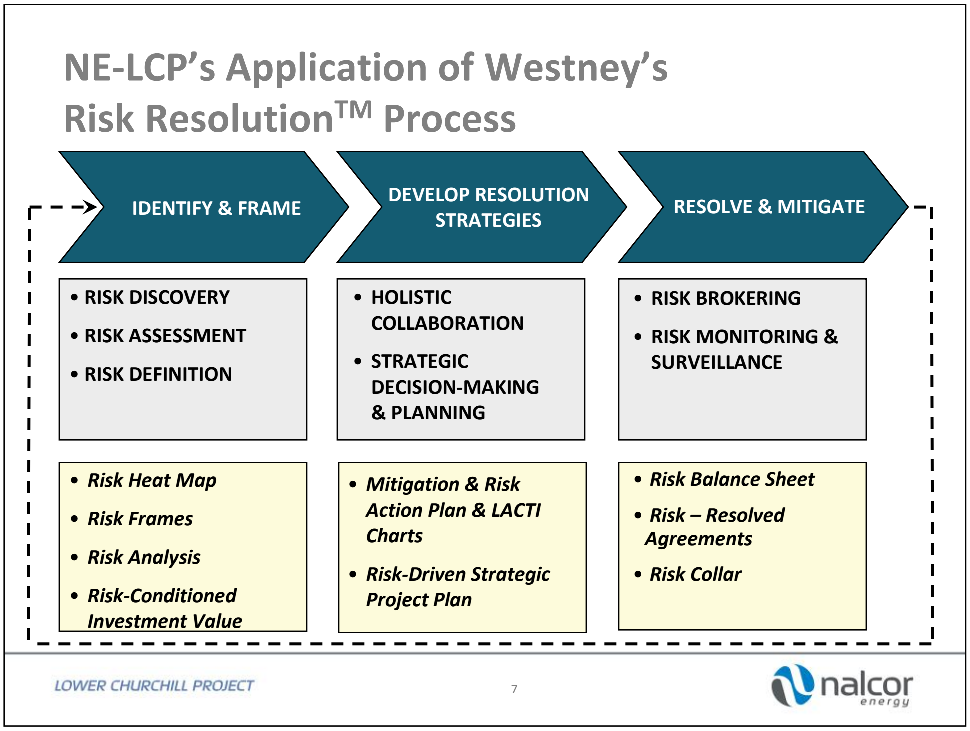
Figure 15: Project Influence Curve (Westney, 2008)



To this effect, in 2007 Nalcor engaged Westney Consulting Group to assist with the full implementation of a holistic risk management program with the Project. Westney are well known and respected within the capital project industry for their leading-edge ideologies and approaches to addressing risks as a means to improve the predictability of the investment decision.

As illustrated in Figure 16 Nalcor has adopted Westney's Risk Resolution® methodology as the backbone of its risk management process for the Project.

Figure 16: Nalcor's Application of Westney's Risk Resolution Methodology



Westney's Risk Resolution® methodology represents a departure from the conventional approach to project risk management whereby risk analysis is focused on tactical risks. According to Westney, both tactical and strategic risks should be considered.

Tactical risks and strategic risks are differentiated below:

<u>Tactical Risks</u>

- *Definition Risks* – These risks are associated with the degree of design development and planning definition for the given project scope, including such items as rock quantities, changing design criteria, location-driven factors, etc.
- *Performance Risks* – These risks are associated with normal/reasonably expected variations in owner and contractor performance, including such items as construction productivity risk, weather delays, material pricing, etc.

Strategic Risks

- *Background (external) Risks* – These are typically associated with changes in: scope, market conditions, location factors, commercial or partner requirements and behaviours.
- *Organization (internal) Risks* – These risks are typically associated with an asymmetry between size, complexity, and difficulty of projects and the organization's ability to deliver.

Risk Management Approach and Methodology

Application of the Risk Resolution® methodology began when the Project was in its earliest, formative stage and before major business decisions or commercial commitments were made. This methodology started with the identification and framing of all business and project risks with a technique called Risk Framing, which provides a means of assessing risk exposure prior to finalizing input parameters into the economic model used for investment evaluation. Through the use of interviews, surveys and analyses, major sources of risk and possible mitigation strategies were identified. Scenarios were created to represent the best- and worst-case outcomes for each type of risk, and then used as input to purpose-built, Monte-Carlo simulation models for cost and schedule that provide a range of possible values for Risk Exposure as input into risk-informed decision making.

Nalcor's specific risk management programs for the Project are built upon a framework that includes five categories:

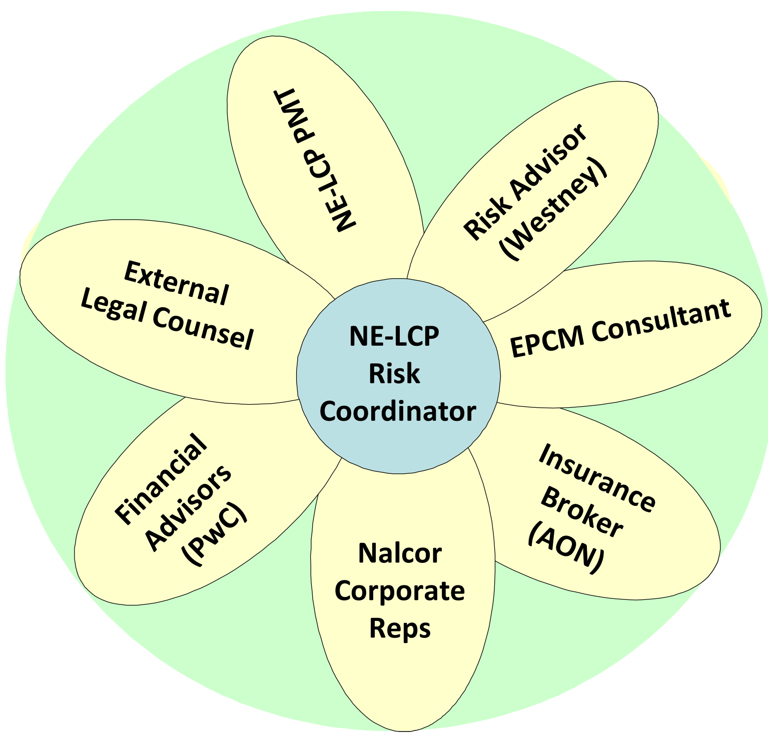
- *Commercial*: Including risks to how the capital project will produce revenue via power purchase agreements with suppliers, off-takers, transmission access and tariffs, reservoir production rates, etc.
- *Financial*: Including risks to how the project's capital investment will be paid for via arrangements with partners, lenders, etc.
- *Regulatory and Stakeholder*: Includes risks regarding regulatory approvals, aboriginal negotiations and agreements, stakeholder engagement, etc.

- *Technical*: Including risks of the technology to be used to create the facilities required to produce the expected revenue, and the physical scope of those facilities.
- *Execution*: Including risks to the organization and contracting strategies for performing the engineering, procurement, construction, installation and start-up; and the plans for managing those activities.

<u>Risk Management Philosophy</u>

The underlying risk management philosophy adopted by Nalcor has been to package and allocate Project risks to the party who can most effectively manage the risks. The ability of Nalcor to allocate these risks will be very much dependent on the risk appetite of the various stakeholders (e.g. contractors, off-takers, insurance underwriters, etc.). A Risk Resolution Team was formed in 2007 to determine the optimal resolution strategy for the identified risks. Since then, this multi-faceted and disciplinary team, illustrated in Figure 17, has successfully developed and implemented mitigation strategies and plans for a number of risks to the Project.

Figure 17: Nalcor's Risk Resolution Team for the Project



Nalcor has extensively used risk-informed decision-making techniques to facilitate decision quality assurance for all aspects of the business case evaluation and project planning. While Nalcor considers it to be impractical to think that it can identify and manage all risks to which the Project may be exposed, the risk-informed decision-making approach facilitates decision analysis that is inclusive of all risk and uncertainty considerations.

Project Specific Risk Profile

The early implementation of this risk management process has afforded the ability to understand the specific risk profile of the Muskrat Falls and Gull Island developments, including the identification of unique and common risks to both developments.

From an evaluation of both common and project-specific risks it has been concluded that the construction risk profile for the Gull Island development is significantly more than for the smaller Muskrat Falls development, in particular considering the exposure to strategic risks such as labour supply and demand. The construction of the smaller Muskrat Falls project requires a smaller capital outlay (thus a smaller equity contribution and debt financing) and a smaller construction effort (i.e. skilled labour demand) than the larger Gull Island project. Similarly, the physical layout of Muskrat Falls project does not present some of the technical and execution challenges that the larger Gull Island project provides, in particular the need to construct diversion tunnels for the temporary diversion of the river, the need to establish a construction bridge across the river, the very large excavation and materials handling volumes, and the very large structures (e.g. 11 million m^3 CFRD main dam). These factors result in smaller technical and construction execution risks for Muskrat Falls than Gull Island.

5.0 Developing Cost Estimates and Project Schedule

In this section, an overview of the process used to develop the capital cost estimates for DG2 is provided. Assumptions on estimate class and accuracy are presented along with the three major components of the capital cost estimate; base estimate, estimate contingency and escalation allowance[18].

During the lifecycle of all projects, such as the Lower Churchill Project, it is typical for the capital cost estimate to evolve as the project definition matures. Cost estimates for both the Muskrat Falls and LIL projects have followed such a progression from the late 1990's to present. During this time further technical and execution studies have revealed new insights, constraints, and opportunities that must be considered in the selection of final design layouts, execution strategies, and construction schedules, all of which have led to the ultimate determination of the DG2 cost estimate, shown in Table 2.

[18] Nalcor Energy, MF and LIL Overview of DG2 Capital Cost and Schedule Estimates. (Exhibit CE-51)

Table 2: Summary of Muskrat Falls and LIL Capital Cost Estimate ($ millions)

Project	Base Estimate	Historical Cost (pre 2010)	Adjusted Base Cost (Base Cost – Historical)	Estimate Contingency 15%	Escalation Allowance	Total Project Cost (excluding IDC)
Muskrat Falls Generating Facility	$2,206	$20	$2,186	$328	$335	$2,869
Labrador – Island Transmission Link (with Overload Capacity)	$1,616	$42	$1,574	$236	$208	$2,060
Total						**$4,929**

Notes:
1. Estimate Contingency = 15 percent of Adjusted Base Cost
2. Escalation and Contingency are applied to Adjusted Base Cost

Nalcor has adopted the recommended estimating practices of the Association for Advancement of Cost Engineering (AACE) International for use in planning the development of the Lower Churchill Project. AACE International is recognized within the engineering, procurement and construction industry as the leading authority in total cost management, including cost estimating standards, practices and methods. AACE International's Cost Estimate Classification System[19], provides guidelines for applying the general principles of estimate classification to project cost estimates. Nalcor Energy has leveraged AACE's Cost Estimate Classification System to map the level of estimate maturity required for each of the gate decisions within Nalcor's Gateway Process.

As discussed earlier, the current capital cost estimates for Muskrat Falls and the Labrador-Island Link Transmission were prepared for the purposes of supporting a Decision Gate 2 (DG2) screening and feasibility recommendation, and are commensurate with the level of technical and execution detail available (i.e. reflect the latest project definition arrived at from the completion of engineering studies and field investigations). The Muskrat Falls project is based upon the Variant 10, Scheme 3b layout which includes a radial gate spillway,

[19] AACE International Recommended Practice No. 17R-97

and temporary diversion through the spillway structure in lieu of temporary diversion tunnels as had been contemplated with Variant 7 in 1998, which is the design on which previous capital cost estimates were based. Similarly, the current LIL project scope has also changed since previous estimates. This scope reflects a smaller HVdc system than envisioned in 1998 (320 kV versus 400 kV), with the HVdc converter located at Muskrat Falls rather than Gull Island.

The DG2 cost estimate is founded in all technical, execution, and market intelligence related studies / investigations completed to-date, and explicitly leverages the extensive engineering studies and execution planning completed during the period of 2007 – 2010, referenced as Gateway Phase 2 within Nalcor's Gateway Process. The principal purpose of the estimate was to support the evaluation and selection of the optimal development scheme for the Lower Churchill River's energy resources.

With careful consideration of the key factors of engineering definition, project execution planning, and knowledge of site conditions, including the findings from IPA's Pacesetter Review conducted in August 2010, Nalcor considers the DG2 capital cost estimate to be an appropriate feasibility-level estimate commensurate with an AACE International Class 4 estimate, thereby meeting the requirements for DG2 of Nalcor's Gateway Process.

5.1 DG2 Cost Estimate Development Process

During Gateway Phase 2, engineering and project execution planning proceeded concurrently with investment analysis. These two analyses were synchronized when capital cost flows for the development options were fed into the economic model.

The key steps in the overall process flow for the development of the Decision Gate 2 Capital Cost Estimate are summarized below, which resulted in cost flows for input into economic modeling, which included cumulative present worth (CPW) analysis. This process, developed by Nalcor, is designed to ensure clear and well managed interfaces between all three components of the Capital Cost Estimate as well as to ensure quality information is used for financial and economic modeling activity.

The basis and development of each of these three major components of the Capital Cost Estimate listed below are discussed in the following sections:

- Section 5.1.1 – Component A: Base Estimate
- Section 5.1.2 – Component B: Estimate Contingency
- Section 5.1.3 – Component C: Escalation Allowance

5.1.1 Component A: Base Estimate

Overview

The Base Estimates for Muskrat Falls and LIL have been developed in accordance to the principles found in AACE International Recommended Practice No. 36R-08. The Base Estimate was developed using four key inputs shown in Figure 18 and in accordance to the Work Breakdown Structure (WBS) shown in Figure 19. The Base Estimate is aligned with the DG2 Basis of Design.

Figure 18: 4 Key Inputs into the Base Estimate

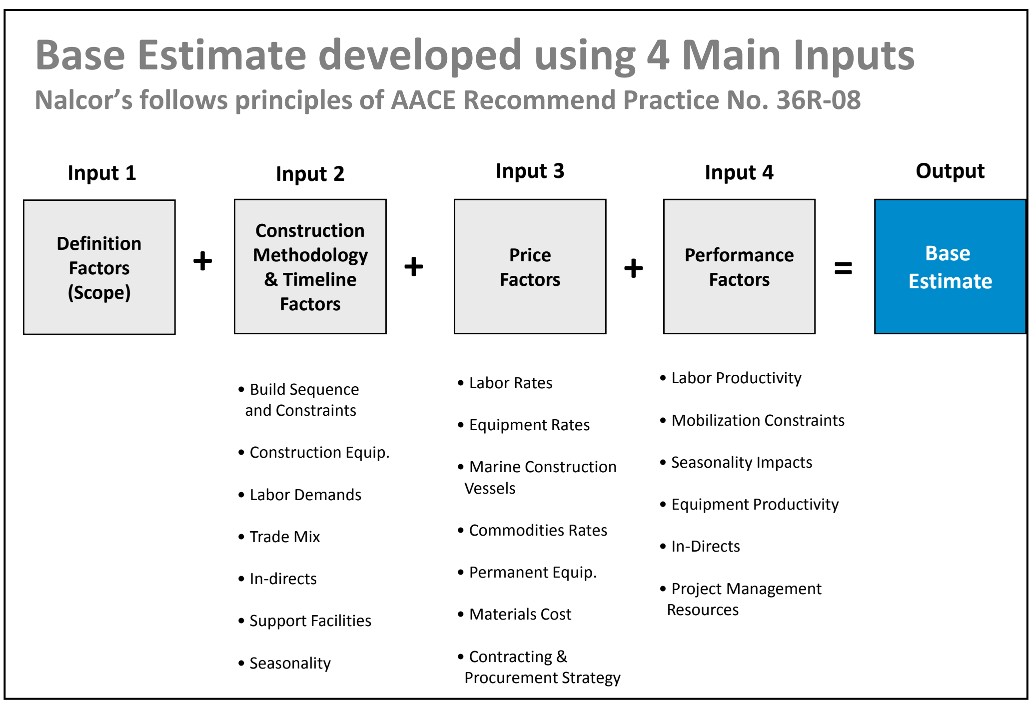


Figure 19: Work Breakdown Structure (WBS)- Excludes Gull Island WBS

1 LCP General
- 1.0 LCP General
  - 1.0.00 General Administration
- 1.1 Project Management
  - 1.1.00 Project Management General
- 1.2 Engineering
  - 1.2.00 Engineering General
- 1.3 Environmental Affairs
  - 1.3.00 Envronmental Affairs General
- 1.4 Aboriginal Affairs
  - 1.4.00 Aboriginal Affairs
- 1.5 Construction Management
  - 1.5.00 Construction Management General
- 1.8 Power Sales and Marketing
  - 1.8.00 Power Sales and Marketing General
- 1.9 Project Financing
  - 1.9.00 Project Financing General

3 Muskrat Falls
- 3.0 Muskrat Falls General
  - 3.0.00 Muskrat Falls General
- 3.1 Infrastructure and Support
  - 3.1.00 Infrastructure and Support General
  - 3.1.10 Offices
  - 3.1.11 Access
  - 3.1.13 Construction Power
  - 3.1.14 Construction Telecommunications
  - 3.1.15 Accomodation Complex
  - 3.1.16 Site Services
  - 3.1.17 Housing Facilities HVGB
  - 3.1.18 Offsite Logistics Infrastructure and Support
- 3.2 Generation Facility
  - 3.2.00 Generation Facilty General
  - 3.2.21 Reservoir
  - 3.2.23 Dams and Cofferdams
  - 3.2.24 Spillway
  - 3.2.25 Approach Channel
  - 3.2.28 North Spur
  - 3.2.31 Tailrace
  - 3.2.32 Intake
  - 3.2.33 Powerhouse and Related Facilities
  - 3.2.34 Turbines and Generators
  - 3.2.35 Balance of Plant
  - 3.2.92 Operations Telecommunications
- 3.4 Switchyards
  - 3.4.00 Switchyards General
  - 3.4.10 Churchill Falls Switchyard Extension
  - 3.4.30 Muskrat Falls Switchyard
- 3.6 OL Transmission
  - 3.6.00 OL Transmission General
  - 3.6.14 AC Tx Muskrat Falls to Churchill Falls
  - 3.6.16 AC Collector Lines to Switchyards
- 3.9 Habitat Compensation
  - 3.9.00 Habitat Compensation General
  - 3.9.11 Muskrat Falls Fish Habitat Compensation
  - 3.9.12 Muskrat Falls Terestrial Habitat Compensation

4 Island Link
- 4.0 Island Link General
  - 4.0.00 Island Link General
- 4.1 Infrastructure and Support
  - 4.1.00 Infrastructure and Support General
  - 4.1.10 Offices
  - 4.1.11 Access
  - 4.1.13 Construction Power
  - 4.1.14 Construction Telecommunications
  - 4.1.16 Site Services
  - 4.1.17 Housing Facilities
  - 4.1.18 Offsite Logistics Infrastructure and Support
- 4.4 Switchyards
  - 4.4.00 Switchyards General
  - 4.4.50 Soldiers Pond Switchyard
- 4.6 OL Transmission
  - 4.6.00 OL Transmission General
  - 4.6.13 AC Tx Muskrat Falls Switchyard to Converter Station
  - 4.6.22 DC TX SOBI to Soldiers Pond
  - 4.6.27 DC Tx Muskrat Falls to SOBI
  - 4.6.31 Electrode Line - Labrador
  - 4.3.32 Electrode Line - Newfoundland East
- 4.7 System Upgrades
  - 4.7.00 System Upgrades General
  - 4.7.10 Island Upgrades - East
- 4.8 DC Specialties
  - 4.8.00 DC Specialties General
  - 4.8.11 Marine Crossing - SOBI
  - 4.8.21 Labrador Converter Station
  - 4.8.22 Soldiers Pond Converter Station
  - 4.8.51 Transition Compound Labrador
  - 4.8.52 Transition Compound Northern Peninsula
  - 4.8.61 Electrode Labrador
  - 4.8.62 Electrode Newfoundland East
- 4.9 Habitat Compensation
  - 4.9.00 Habitat Compensation General
  - 4.9.11 Island Link Fish Habitat Compensation

5 Maritime Link
- 5.0 Maritime Link General
  - 5.0.00 Maritime Link General
- 5.1 Infrastructure and Support
  - 5.1.00 Infrastructure and Support General
  - 5.1.10 Offices
  - 5.1.11 Access
  - 5.1.13 Construction Power
  - 5.1.14 Construction Telecommunications
  - 5.1.16 Site Services
  - 5.1.17 Housing Facilities
  - 5.1.18 Offsite Logistics Infrastructure and Support
- 5.4 Switchyards
  - 5.4.00 Switchyards General
  - 5.4.60 Maritime Switchyard
  - 5.4.70 Bottom Brook Switchyard
  - 5.4.80 Granite Canal Switchyard
- 5.6 OL Transmission
  - 5.6.00 OL Transmission General
  - 5.6.17 AC Tx Bottom Brook to Granite Canal
  - 5.6.26 DC Tx Cape Ray to Bottom Brook
  - 5.6.33 Electrode Line - Maritimes
  - 5.6.34 Electrode Line - Newfoundland West
- 5.7 System Upgrades
  - 5.7.00 System Upgrades General
  - 5.7.20 Island Upgrades - West
  - 5.7.30 Maritime Upgrades
- 5.8 DC Specialties
  - 5.8.00 DC Specialties General
  - 5.8.12 Marine Crossing - Maritimes
  - 5.8.23 Maritime Converter Station
  - 5.8.24 Newfoundland West Converter Station
  - 5.8.53 Transition Compound Newfoundland West
  - 5.8.54 Transition Compound Maritimes
  - 5.8.63 Electrode Maritime
  - 5.8.64 Electrode Newfoundland West
- 5.9 Habitat Compensation
  - 5.9.00 Habitat Compensation General
  - 5.9.11 Maritime Link Fish Habitat Compensation

Procurement and Construction Costs

In the case of the Muskrat Falls Generating Facility where detailed definition exists, significant portions of the Base Estimate have been developed using a comprehensive and detailed approach working from the lowest level of detail and building the estimate up, using available information on quantities, unit costs, wage rates, bulk construction consumables (e.g. Portland cement, diesel fuel, rebar, etc.) construction fleet costs, major permanent equipment quotations, and historical production rates. In some areas such as the balance of plant and spillway gates, third party benchmarks from as-built plants combined with current unit costs have formed the basis of the estimate.

Supporting information for the Muskrat Falls Base Estimate comes from a combination of sources, including the site layouts and quantities contained in reports from experienced consultants and input from the LCP Project Team.

In the case of the Labrador – Island Transmission Link, the Base Estimate has its foundation set in the 450 kV line studied extensively in the period of 2007 – 2010, including studies and field investigations. This has been significantly augmented with system studies for the current 320 kV link, extensive field work and studies completed for the SOBI cable crossing[20], and preliminary construction and logistics planning for the construction of the overland transmission line. Vendor quotations for major hardware including overhead conductor, insulators, converter stations, and submarine cable has been obtained and included within the estimate.

For estimating purposes each of the Muskrat Falls and LIL projects have been broken down into a series of logical contract packages for construction of various components, for supply and installation of major packages such as turbine/generator units, dams, and for service and support facilities. The estimates for the various contract packages have been developed from the point of view of a contractor and include profit and overhead allowances. The estimates for the specific contract packages have been developed by applying the costs of materials, labour and equipment to the required volume or amount of materials, quantities,

[20] Exhibit CE-44

and construction equipment. Each subcontract includes a separate evaluation of the contractor's indirect costs. Indirect costs such as accommodations and site services have been estimated in detail for Muskrat Falls. Support facilities have been included in the estimate, including accommodation facilities and equipment repair facilities.

The latest construction methods, engineering technologies and market intelligence are critical to ensuring that the estimate contains current information. To that end, a number of qualified, reputable, experienced external engineering companies and individual consultants have been engaged to provide engineering studies (e.g. SNC-Lavalin, Hatch, RSW and others), scope definition, estimating and construction experience, and market data for inclusion in the estimate.

The basis of productivity used in the estimate is rooted in the underlying assumptions regarding installation methodology (including equipment) and constraints. Labour productivity assumptions for Muskrat Falls and LIL are based on experience on previous hydro, large civil and transmission projects.

A detailed labour rate study has resulted in the establishment of labour rates for the development of the cost estimate, which are considered competitive with other eastern Canada megaprojects.

Estimates for permanent plant equipment (e.g. turbines, submarine cable, transmission towers, insulators, converter stations, transformers) have been based upon recent quotations received from manufacturers, while prices for key construction consumables (e.g. rebar, explosives, etc.) have been obtained from vendors.

Construction fleet costs have been developed from a contractor's viewpoint using current market prices for new equipment, combined with industry data on usage and repair (e.g. Caterpillar Performance Handbook 38), Nalcor's diesel fuel prices, and prudent assumptions on equipment depreciation. The resultant prices have been benchmarked with other hydro developers and with relevant industry benchmarks (e.g. McGraw-Hill's Equipment Watch).

Key construction consumables (e.g. rebar, Portland cement, explosives, etc.) are based upon quotations from major suppliers assuming delivery to the Muskrat Falls construction site, which selective benchmarking of these has been done against McGraw-Hill's Engineering-News Record Material Trends.

An allowance for contractor's overhead and profit has been added to the subtotal of direct and indirect costs.

Owner and EPCM Cost

The Owner, Engineering / Design, and Project / Construction Management costs can be broken down into two major categories: (1) Labour Cost, and (2) Other Cost.

Labour costs are largely comprised of personnel costs associated with completion of the detailed design, engineering, construction management activities, and traditional Owner's activities including overall project management, environmental assessment, etc.

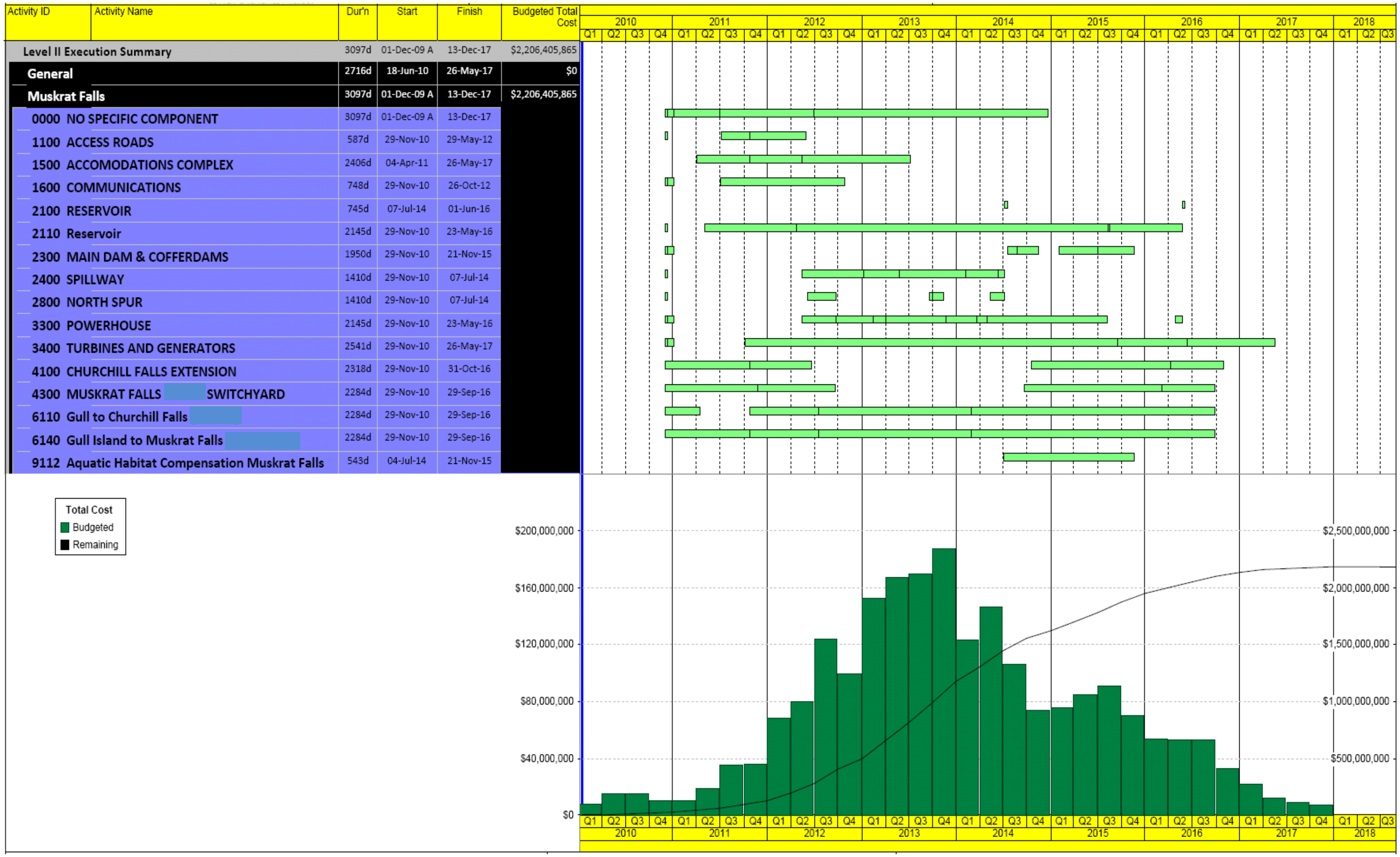
Other Costs are related to non-labour associated costs. Some may be indirectly linked to personnel, such as the office lease, which depends on office size, which in turn depends on staffing levels. Other costs include costs related to office leases, business travel, IT/IS systems and support, helicopter usage, construction insurance, permits and licenses fees, rental and maintenance of project vehicles, public relations, and other miscellaneous items.

Determination of Cost Flows

In general terms, the Base Estimate is broken into key components of material, equipment and labour resource types of each Physical Component (e.g. Powerhouse, Reservoir Clearing, etc.) and is married with the project schedule in Primavera Project Planner to produce cost flows. The resulting cost flows for the Muskrat Falls and LIL Base Estimates are shown in Figures 20 and 21.

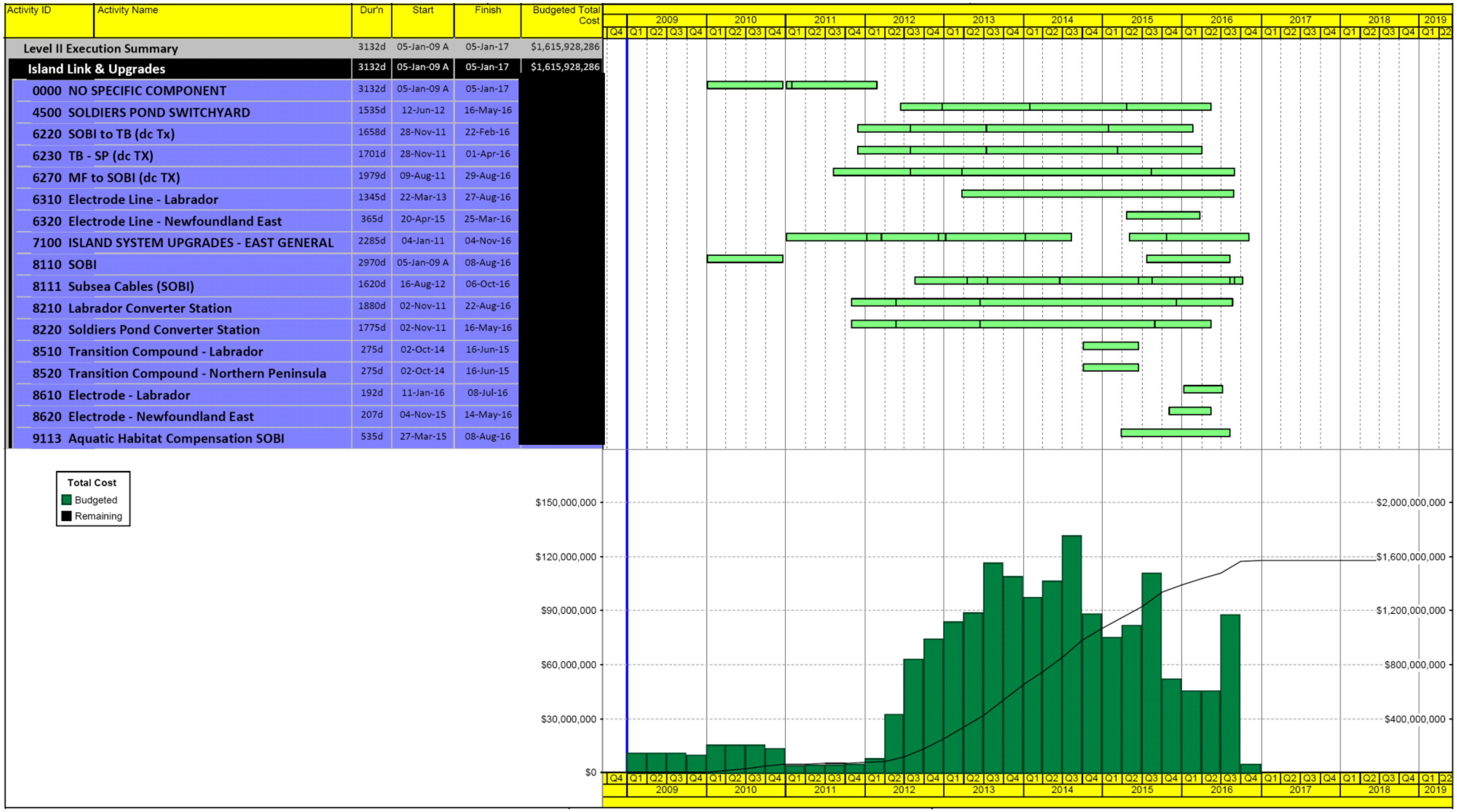
Using a similar approach, the linkage of the Base Estimate and Project Schedule has facilitated the production of labour histograms for each major occupational area.

Figure 20: Cost Flow for Muskrat Falls Generating Facility



1 **Figure 21: Cost Flow for Labrador – Island Transmission Link**

Activity ID	Activity Name	Dur'n	Start	Finish	Budgeted Total Cost
Level II Execution Summary		3132d	05-Jan-09 A	05-Jan-17	$1,615,928,286
Island Link & Upgrades		3132d	05-Jan-09 A	05-Jan-17	$1,615,928,286
0000	NO SPECIFIC COMPONENT	3132d	05-Jan-09 A	05-Jan-17	
4500	SOLDIERS POND SWITCHYARD	1535d	12-Jun-12	16-May-16	
6220	SOBI to TB (dc Tx)	1658d	28-Nov-11	22-Feb-16	
6230	TB - SP (dc TX)	1701d	28-Nov-11	01-Apr-16	
6270	MF to SOBI (dc TX)	1979d	09-Aug-11	29-Aug-16	
6310	Electrode Line - Labrador	1345d	22-Mar-13	27-Aug-16	
6320	Electrode Line - Newfoundland East	365d	20-Apr-15	25-Mar-16	
7100	ISLAND SYSTEM UPGRADES - EAST GENERAL	2285d	04-Jan-11	04-Nov-16	
8110	SOBI	2970d	05-Jan-09 A	08-Aug-16	
8111	Subsea Cables (SOBI)	1620d	16-Aug-12	06-Oct-16	
8210	Labrador Converter Station	1880d	02-Nov-11	22-Aug-16	
8220	Soldiers Pond Converter Station	1775d	02-Nov-11	16-May-16	
8510	Transition Compound - Labrador	275d	02-Oct-14	16-Jun-15	
8520	Transition Compound - Northern Peninsula	275d	02-Oct-14	16-Jun-15	
8610	Electrode - Labrador	192d	11-Jan-16	08-Jul-16	
8620	Electrode - Newfoundland East	207d	04-Nov-15	14-May-16	
9113	Aquatic Habitat Compensation SOBI	535d	27-Mar-15	08-Aug-16	



2

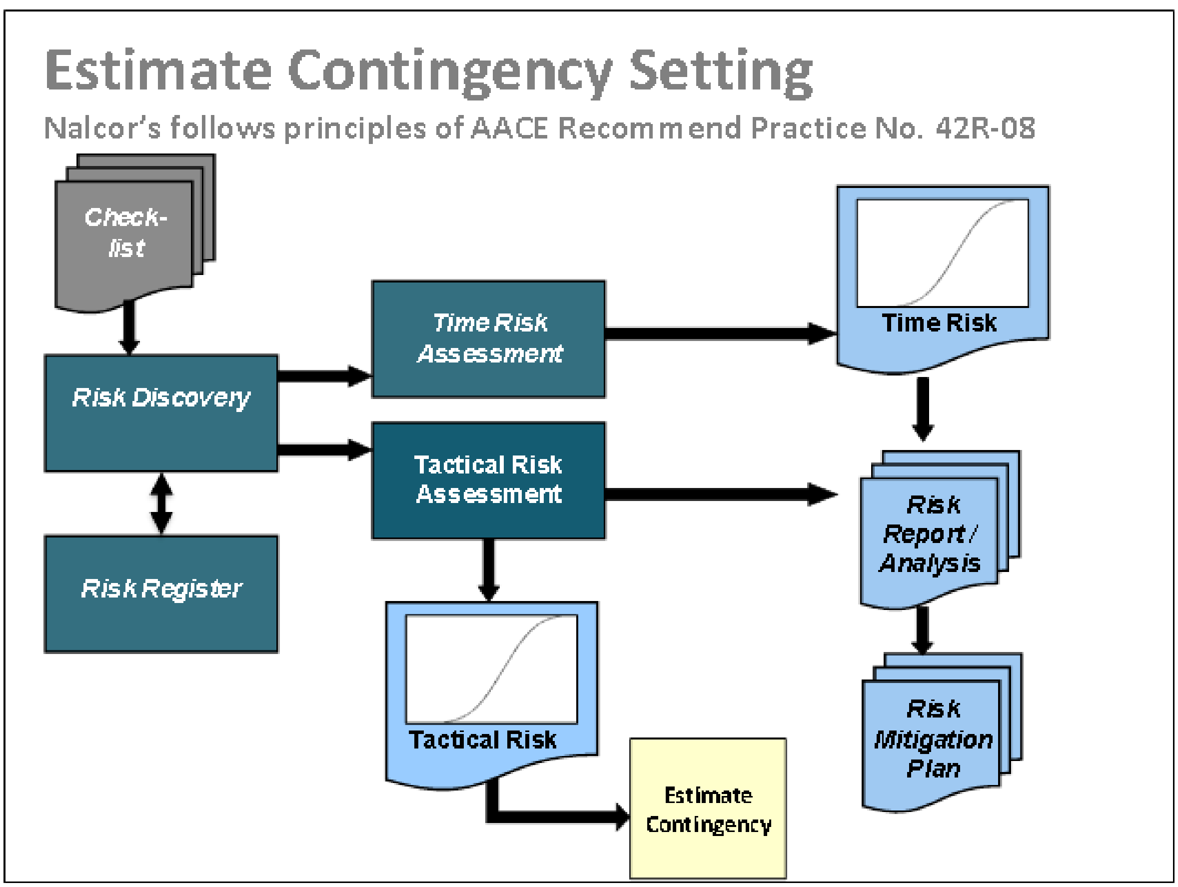
5.1.2 Component B: Estimate Contingency

<u>Process Overview</u>

The Base Estimate is a forecast of costs for a given set of conditions, which include scope of work, schedule and execution plans. The accuracy of the Base Estimate is subject to the details known at the time and provided as input to the estimate. Different classes or types of estimates are required to evaluate capital and other work programs, at various stages of the Project. Estimates are classified in terms of quality, or known accuracy, which improves as the Project or work program proceeds.

For the Project a probabilistic estimating basis has been used in line with the AACE International Recommended Practice 42R-08, with the assistance of Nalcor's risk management consultant, Westney Consulting Group. The general approach is depicted in Figure 22.

Figure 22: Estimate Contingency Setting



Basis of Assessment

In June 2010 Westney were engaged to support Nalcor in completing a tactical risk assessment[21] as input into the final determination of an appropriate Estimate Contingency for DG2. The basis of the assessment was the latest available cost and schedule estimates available at the time of completion of the risk assessment. The results of this initial risk analysis resulted in a recommendation to use 16 percent of the base estimate as an appropriate P50 Estimate Contingency for the Muskrat Falls and Labrador –Island Transmission Link projects. Following this risk analysis there was a progression of the project definition, including engineering field investigations and studies which Nalcor determined would reduce the tactical risk exposure. The additional work carried out since the initial risk analysis resulted in an increase in the capital cost estimate from $3,359 million to $3,822 million and a reduction in the contingency from the initial 16 percent to 15 percent. The Estimate Contingency, an amount included in the estimate in addition to the $3,822 base estimate used for DG2 economic modelling, was $564 million[22].

Results from Tactical Risk Assessment

The Tactical Risk Assessment considers the impact of definition and performance risks (i.e. combination of construction methodology and schedule, performance factors, and price risks) on the Base Estimate. To support the determination of Estimate Contingency, a detailed cost model was prepared for the cost estimate. High / low ranges for each line item of the cost model were then assessed based upon identified tactical risks and uncertainties for each of the four key elements of the Base Cost Estimate: (1) project definition / scope, (2) construction methodology and schedule, (3) performance factors, and (4) price.

Nalcor met with Westney consultants to discuss the Best and Worst Case ranges around the estimate for each cost category. The final ranging was performed by Nalcor, but it was vetted and questioned by the Westney participants. Westney selected the probability distributions to use with the ranged data and ran the Monte Carlo simulation.

---

[21] Nalcor Energy, Technical Note – Strategic Risk Analysis and Mitigation. (Exhibit CE-52)

[22] No contingency need be applied to historical expenditures, and therefore the 15 percent contingency is only applied against the adjusted base estimate as shown in Table 1

<u>Strategic Risk Management and Mitigation Progress at Decision Gate 2[23]</u>

Risk identification activities for the Project have resulted in the identification of a number of key risks. As these key risks can significantly influence the ability to achieve the Project's goals and objectives, they have been and continue to be the focus of significant attention by the PMT to actively mitigate the risk involved. These efforts have resulted in positive progress that have caused Nalcor to decide that a reserve amount above and beyond the 15 percent tactical contingency amount was not required at this time but will be considered further as part of the DG3 decision. The two significant positive contributors are the stated Federal Government support for the project in the form of a Federal Loan Guarantee and the decision to use the more traditional HVdc technology known as Line Commutated Converter technology (LCC) for the Labrador –Island Transmission Project.

<u>Federal Government Support</u>

Negotiations with the federal government regarding support for the Project, either in the form of a loan guarantee or support through the P3 Canada Fund, were ongoing through 2010. A loan guarantee had the potential to reduce the present value of project financing costs by over $600 million, so considering this from a probabilistic view, the P50 value of the federal support could reasonably be in the order of -$300 million dollars. This risk was not quantified in the initial analysis by the Project team.

<u>Application of VSC technology</u>

While Voltage Source Converter (VSC) technology was identified as a potential technical solution for the Labrador Island Transmission Link, modelling completed at DG2 indicated that conventional Line Commutated Converter (LCC) technology offered equivalent performance. As a result, the technology risk (and up to $200 million exposure) was retired. Eliminating this risk could reasonably be valued at -$100 million on a P50 basis.

With the extent of the mitigation activities undertaken and in progress, and probabilistic cost reductions in the order of -$400 million being available and a P50 strategic exposure of $290 million (in the range of $187 million (P25) to $413 million (P75)), Nalcor executive determined that it was not appropriate to create a positive or negative strategic reserve

[23] CE-52

amount at DG2. These factors were also considered in establishing Project tactical contingency at 15 percent.

5.1.3 Component C: Escalation Allowance

Cost escalation for large, long-term construction projects such as the Lower Churchill Project is an important factor in determining the ultimate in-service capital costs. Given the long time period required to construct the Project and the lag between cost estimate development and the start of construction, it is critical to understand the causes and effects of cost escalation to be able to make an estimate of the additional costs required as a result of cost increases expected to be incurred over the course of the construction period.

Background

Escalation refers to cost changes which result from changes in price levels. These changes in price levels in turn are driven by underlying economic conditions. Escalation is driven by changes in productivity, technology, and market conditions, including high demand, labour and material shortages, profit margins, and other factors. Escalation includes the effects of inflation, but is fundamentally different. Inflation refers to general changes in price levels caused by changes in the value of currency and other broader monetary impacts.

Historically, escalation was treated in a simplistic manner. An overall escalation rate was decided upon using global aggregate indices and applied across the entire project costs (i.e. "use 2 percent per year"). Given changes in the economic climate, particularly volatility in commodity prices, skilled labour shortages, overall global economic uncertainty, globalization of the economy, just-in-time inventories, and shortened supply cycles it was determined that a more sophisticated approach to estimating escalation was required.

Approach and Methodology

Following extensive research on the topic, Nalcor Energy engaged the services of Validation Estimating [24] – a US-based consultancy which provides various cost engineering services, including cost escalation services – to assist with developing a cost escalation model for the

[24] Validation Estimating has provided services to numerous large companies, including Aramco, BP, Black and Veatch, Chevron, Dow Corning, Eastman, Enbridge, Manitoba Hydro, Ontario Power, Petro-Canada, Rio Tinto Alcan, and Suncor among others.

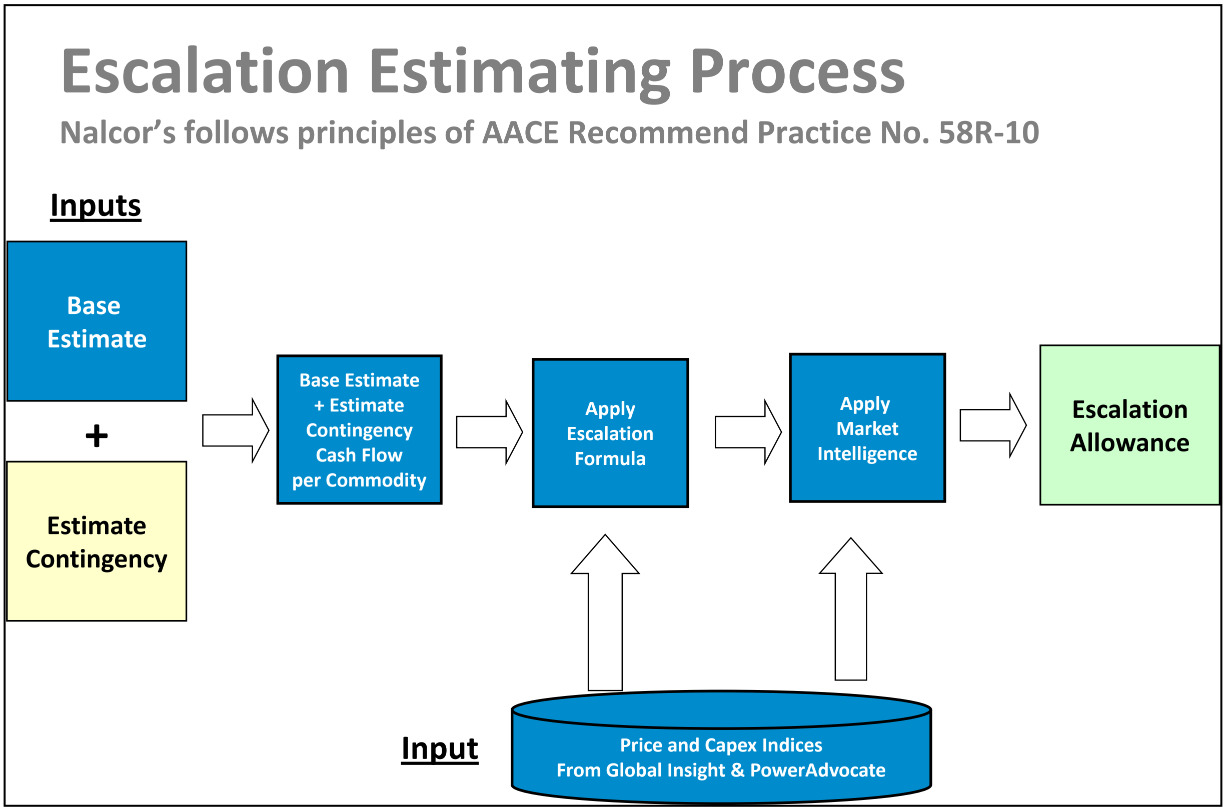
LCP. In its assessment, Validation Estimating recommended a number of best practices for cost escalation. Table 3 below lists the recommended best practices and identifies the extent to which they were met for the Lower Churchill Project escalation model.

Building on these recommended best practices as well principles contained within AACE International Recommended Practice No. 58R-10, Nalcor Energy developed a methodology for estimating cost escalation that links the capital cost estimate with the project scheduling activities, resulting in a model and system that provides time-phased escalation estimates on commodity, project component and aggregate levels. This resulting escalation estimating process is illustrated in Figure 23.

Table 3: Cost Escalation Best Practices

Best Practice as Recommended by Validation Estimating	Included in LCP Escalation Model
Differentiate between escalation, currency and contingency	Yes
Use indices that address differential price trends between accounts	Yes
Use indices that address levels of detail for various estimate classes	Yes
Leverage procurement/contracting specialist's knowledge of markets	Yes
Leverage economist's knowledge (i.e., based on macroeconomics)	Yes
Ensure that a consistent approach is applied in a model that facilitates best practice	Yes
Calibrate data with historical data	Yes
Use probabilistic methods	To be determined pending further investigation
Use the same economic scenarios for business and capital planning	Yes
Include as a part of an integrated project/cost management process	Yes
Facilitate estimation of appropriate spending or cash flow profile	Yes

Figure 23: Escalation Estimating Process



The methodology employed to estimate escalation for the Lower Churchill Project involved is illustrated in Figure 23 above. The result of this process was the creation of a number of escalation "bins" by physical component which were then matched against the project schedule to produce the escalated cash flows for the Project by physical component. The detailed cost estimates for the project components are contained in PRISM Project Estimator[25]. Each line item is detailed with quantities, costs and units for labour, materials, equipment, process equipment and sub-contracts. The costs are expressed in Q1 2010 Canadian dollars.

[25] PRISM Project Estimator is a project cost estimating tool contained within the PRISM software suite provided by Ares Corporation.

Escalation Indices

Indices applied to each of the escalation bins were obtained from one of two forecasting services used by the Nalcor. Global Insight and Power Advocate are two commercial services which provide price and economic forecasting services. The indices from Global Insight are the primary indices used in the analysis. The specific indices used in the DG2 analysis are from Global Insight's Q1 2010 report. For the first two years of the analysis, quarterly indices were used, followed by annual indices thereafter. A brief overview of each service follows.

Global Insight

IHS Global Insight provides the most comprehensive economic, financial, and political coverage available from any source to support planning and decision making. Using a unique combination of expertise, models, data, and software within a common analytical framework, Global Insight covers over 200 countries and more than 170 industries.

Recognized as the most consistently accurate forecasting company in the world, IHS Global Insight has over 3,800 clients in industry, finance, and government with revenues in excess of $100 million, 700 employees, and 25 offices in 14 countries covering North and South America, Europe, Africa, the Middle East, and Asia.

Power Advocate

Established in 1999, Power Advocate is a US-based consultancy which specializes in providing market intelligence and cost forecasting services for the power industry. They provide cost forecasting services at a number of levels from base commodities to the plant/project level (e.g. combined-cycle gas turbine plant or a transmission project). While Global Insight was used as the primary source of indices, they were supplemented where deemed appropriate by information from Power Advocate. The use of Power Advocate's market intelligence was limited because they do not provide any hydro-specific indices or analysis.

Calculated Escalation

The calculated cumulative escalation factors and resulting cumulative escalation for Muskrat Falls Generating Facility and the Labrador – Island Transmission Link, using the Escalation Model developed in accordance to the above methodology is provided in Table 4.

Table 4: Calculated Escalation Factors

Component	2010	2011	2012	2013	2014	2015	2016	2017	2018	Estimated Cumulative Escalation
Muskrat Falls Generating Facility	1.00	1.02	1.05	1.11	1.16	1.20	1.23	1.26	1.30	$335 million
Labrador – Island Transmission Link	1.00	1.02	1.04	1.08	1.12	1.16	1.20	1.24	1.29	$208 million

5.4 Project Schedule

The Project Schedule for the Lower Churchill Project is based upon extensive studies and planning work carried out for the development of the Lower Churchill river since late 2006. The overall Project Schedule following DG3 is designed to be a construction activity driven schedule, with engineering and procurement activities scheduled to support the advancement of construction. The desire to have the supply and installation of the turbine and generator sets as the critical path with the civil construction support installation program.

In advance of DG2 a control-level schedule, referred to as the Project Control Schedule (PCS), was established to as the overall control plan that will be used by Nalcor for monitoring and controlling progress and performance on Project, as well as forms the basis for all cost flows developed in support of economic modeling.

The DG2 PCS represented a roll-up of approximately 800 activities from more detailed engineering, procurement, construction, environmental assessment, and other schedules developed by the PMT using internal and external specialized resources. It represents the envisioned execution sequence as understood at the time of its issue. The DG2 PCS is closely aligned with DG2 Base Estimate, with schedule durations aligned with production rates in the estimate.

The PCS includes overall milestones established for the Project, key activity schedule durations, and key dates. The schedule contains the following for each major Project component:

- Entire scope of the Project component;
- Project key dates (dates to be monitored which are not milestones);
- Overall critical path;
- Key delivery dates;
- Significant durations;
- Activities representing the major Project components; and
- Logic, both internal and between Project components.

The DG2 planning basis targets first power from Muskrat Falls in 2016, with full power in 2017. The construction schedule assumes that construction occurs throughout the winter, while the seasonal nature of portions of the work, such as Muskrat Falls RCC dam construction, has been considered when developing the labour and equipment requirements.

Target Milestone Schedule as of DG2

(Muskrat Falls + Island Link)

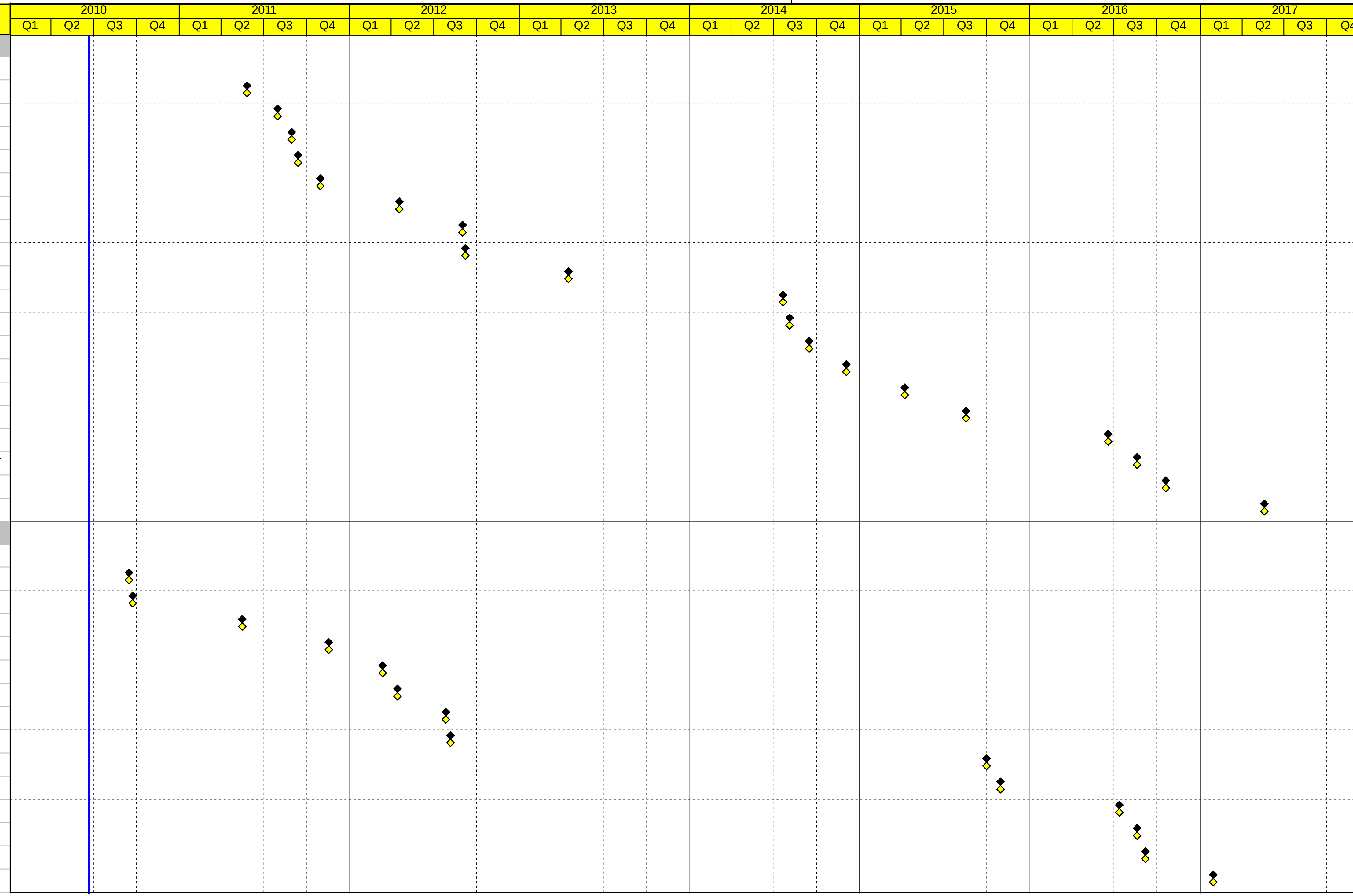
Activity Name

Muskrat Falls

- TARGET: SUBMIT GENERATION EIS
- TARGET: AWARD PURCHASE ORDER FOR SUPPLY & INSTALLATION OF ACCOMODATIONS COMPLEX
- TARGET: ENVIRONMENTAL ASSESSMENT RELEASE FOR GENERATION PROJECT
- TARGET: READY TO COMMENCE RESERVOIR PREPARATION
- TARGET: READY TO COMMENCE SITE INFRASTRUCTURE WORKS (e.g. SOUTH SIDE ACCESS ROAD FOR
- TARGET: MUSKRAT FALLS SOUTH SIDE ACCESS ROAD READY FOR USE
- TARGET: AWARD PRIMARY CIVIL CONSTRUCTION CONTRACTS (POWERHOUSE & SPILLWAY)
- TARGET: MUSKRAT FALLS PHASE 1 CAMP READY FOR USE
- TARGET: AWARD CONTRACT FOR SUPPLY & INSTALL OF MUSKRAT FALLS TURBINES & GENERATORS
- TARGET: POWERHOUSE EXCAVATION (INCL. INTAKE & TAILRACE) COMPLETE
- TARGET: COFFERDAMS COMPLETED & RIVER DIVERTED THROUGH SPILLWAY
- TARGET: SOUTH RCC DAM COMPLETE
- TARGET: POWERHOUSE CRANE READY FOR USE
- TARGET: DELIVERY COMPLETE FOR TURBINE/GENERATOR UNIT #1
- TARGET: POWERHOUSE PRIMARY CONCRETE COMPLETE
- TARGET: NORTH RCC DAM COMPLETE
- TARGET: READY TO COMMENCE RESERVOIR IMPOUNDMENT
- TARGET: MUSKRAT FALLS TO CHURCHILL FALLS TRANSMISSION INTERCONNECT READY FOR POWER T
- TARGET: FIRST COMMERCIAL POWER AVAILABLE FROM MUSKRAT FALLS
- TARGET: FULL COMMERCIAL POWER AVAILABLE FROM MUSKRAT FALLS

Island Link & Upgrades

- TARGET: SUBMIT ISLAND LINK EA REGISTRATION
- TARGET: DECISION ON PROJECT CONFIGURATION OF LABRADOR-ISLAND TRANSMISSION LINK
- TARGET: DECISION ON SOBI CROSSING APPROACH
- TARGET: SUBMIT EIS FOR LABRADOR-ISLAND TRANSMISSION LINK
- TARGET: AWARD CONTRACT FOR SUPPLY OF SOBI CABLE & CROSSING
- TARGET: OVERLAND TRANSMISSION MATERIALS ORDERED
- TARGET: ENVIRONMENTAL RELEASE FOR LABRADOR-ISLAND TRANSMISSION LINK
- TARGET: AWARD EPC CONTRACT FOR HVdc CONVERTER STATIONS
- TARGET: READY TO COMMENCE CONSTRUCTION ON OVERLAND TRANSMISSION (dc)
- TARGET: SOBI CABLE PROTECTION SCOPE COMPLETE
- TARGET: SOBI CABLE INSTALLATION COMPLETE
- TARGET: ISLAND LINK OVERLAND TRANSMISSION CONSTRUCTION COMPLETE
- TARGET: READY TO COMMENCE SYSTEM INTEGRATION TESTING
- TARGET: ISLAND LINK HVdc CONVERTER STATIONS COMPLETE
- TARGET: LABRADOR-ISLAND TRANSMISSION SYSTEM READY FOR POWER TRANSMISSION



Baseline Milestone

Milestone

File: LC - NE-LCP MF+IL Project Schedule

Doc. No. LCP-PT-ED-0000-EP-SH-0001-01

Date	Revision	Checked	Approved
15-Oct-10	REV. B1 - ISSUED FOR USE		

The driving logic for the Project Control Schedule includes:

- Obtaining EA release, which is required to facilitate the permitting required to start early works / infrastructure construction;
- The completion of geotechnical evaluations at Muskrat Falls to confirm key parameters required by the EPCM Consultant to complete engineering drawings to be included in construction packages;
- The mobilization of the EPCM Consultant which will perform the detailed design, in order to permit the design and contracting for the site works and mass excavation;
- Final feasibility engineering studies to be finalized in the first half of 2011;
- Early Site Infrastructure Works for Muskrat Falls (access, accommodations, communications, construction power) to commence following EA release and permitting;
- The completion of powerhouse excavation and primary and secondary concreting, in order to allow the assembly of the turbine/generator units; and
- First Power from Muskrat Falls via Churchill Falls in Q4-2016.

The critical path for this schedule includes the following milestones:

- Award of the EPCM contract and the mobilization of the EPCM consultant;
- Pre-EPCM site design for the Muskrat Falls generating site;
- Critical design elements, such as the design package for the main civil works, the SOBI crossing, converter stations, and the HVdc overhead transmission system;
- Turbine model testing;
- The award of the turbine/generator supply and installation contract;
- The manufacturing and delivery of the embedded components for turbine unit No. 1 (specifically, the stay ring);
- Release from both the Generation Project and LIL EA processes;
- Development of access to the generation site;
- The final excavation of the powerhouse and intake;
- Secondary concreting and structural steel related to turbine unit No. 1;

- Installation, assembly and commissioning of turbine unit No. 1;
- Commissioning of subsequent turbine units 2 to 4;
- Contracting processes for the overland dc transmission;
- Contract award and detailed design for the SOBI crossing;
- Installation and protection of the SOBI cables; and
- Contract award, construction and commissioning of the HVdc converter stations at Soldiers Pond and Muskrat Falls.

6.0 Conclusion

Nalcor and the Lower Churchill Project Management Team are employing the best practice Gateway decision process to develop Muskrat Falls as part of the Interconnected Island alternative. The capital cost estimates for Muskrat Falls and LIL projects at DG2 were developed using practices of the AACE International. They reflect the appropriate project definition arrived at from the completion of engineering studies and field investigations. Construction methodologies and supporting policies and procedures are typical for what would be expected for the development of a large scale construction project. All of the technology employed is proven and widely used around the world. The project has undergone extensive risk management procedures in order to ensure the project is able to maintain schedule and budget to the greatest extent possible while retaining a relentless focus on safety and environmental management.