Independent Supply Decision Review

Prepared for:

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ABOUT NAVIGANT CONSULTING

Navigant (NYSE: NCI) is a specialized, global expert services firm dedicated to assisting clients in creating and protecting value in the face of critical business risks and opportunities. Through senior level engagement with clients, Navigant professionals combine technical expertise in Disputes and Investigations, Economics, Financial Advisory and Management Consulting, with business pragmatism in the highly regulated Construction, Energy, Financial Services and Healthcare industries to support clients in addressing their most critical business needs.

Navigant's Energy Practice offers a wide range of services including business planning, performance improvement and benchmarking services, renewable energy, energy efficiency, emerging technology, natural gas and energy generation, smart grid and transmission.

In the context of the Independent Supply Decision Review, Navigant brings:

- Deep experience in supply planning, generation costing, demand forecasting and integrated resource planning
- Understanding of standard industry practices and best practices regarding supply planning and demand forecasting, and
- Extensive experience in developing market price forecasts in competitive power markets and marginal costing and revenue requirements in regulated electricity markets.

Navigant has worked with many utilities in integrated resource planning in which Navigant assessed energy efficiency, renewable, self build, asset acquisition and power purchase agreement resource alternatives. In these projects, Navigant built and managed financial screening tools that allowed for rapid turn-around in the review of different planning scenarios, assessed and implemented methodologies for comparing resource options of different lives and sizes, and calculating the revenue requirement impacts of each resource option considered. Navigant has conducted workshops covering: risk analysis methodologies, resource planning related software available in the market place, demand response and efficiency assessment techniques, and renewable resource evaluation. Navigant has educated clients on resource planning rules and requirements across different jurisdictions.

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EXECUTIVE SUMMARY AND KEY FINDINGS

Nalcor Energy has proposed a plan for the long term electricity supply for the Island of Newfoundland. This plan passed through Decision Gate 2 (DG2) where the Muskrat Falls with the Labrador-Island Link was chosen as the preferred alternative to meet future energy needs. Nalcor's Gateway Process is designed to ensure decisions are made at appropriate times, with the appropriate level of information, and at appropriate levels of expenditure. It focuses on key milestones to achieve gateway readiness and builds in "cold eyes" reviews at key decision points throughout the process.

Decision Gate 3 (DG3) – Project Sanction is the next step in the process. DG3 requires the advancement of project activities and work streams to a level of progression which provides the certainty needed to sanction or go ahead with the Project. Nalcor has retained Navigant to conduct an initial review using DG2 estimates. This report presents Navigant's findings related to Nalcor's recent DG2 decision. Navigant will provide a second report using DG3 project cost and schedule information as input to the DG3 decision.

Options Considered by Nalcor

Nalcor's DG2 decision evaluated a number of potentially feasible generation expansion alternatives for the long-term supply of electricity to the Island of Newfoundland. The alternatives fell into two broad categories: 1) Isolated Island alternatives, and 2) Interconnected Island alternatives. The optimal generation plan for each category was selected from the potential feasible alternatives in each category. The optimal generation expansion plan in each of these two categories is described below:

1. ***Isolated Island*** alternative would entail continued isolation of the Island power grid and the inherent supply and operational limitations associated with isolation. The key elements are:
   - Development of limited renewable resources in the near-term
   - Pollution abatement, life extension improvements at the Holyrood plant, replacement of the Holyrood plant, and
   - Continued development of thermal power resources across the planning period 2010 to 2067.

2. ***Interconnected Island*** alternative would provide the capability to displace the Holyrood plant and meet the growth in provincial power requirements for years to come. In addition, this alternative would interconnect the Island with the regional North American power grid. The key elements are:
   - Muskrat Falls generation facility, and
   - Labrador-Island Link (LIL) transmission facility.

Nalcor's DG2 Results

Based on the assumptions, inputs and analysis undertaken by Nalcor, the Cumulative Present Worth (CPW, present value in 2010$ of annual utility revenue requirements) for each of the two generation expansion alternatives is shown in the following table.

Generation Expansion Alternative	Cumulative Present Worth (CPW) 2010$ millions
Isolated Island	$8,810
Interconnected Island	$6,652
Preference for Interconnected Island	**$2,158**

As shown above, Nalcor projects that developing the Interconnected Island alternative will result in lower utility costs for customers of $2.2 billion in present value terms through 2067 as compared to the Isolated Island alternative.

Navigant's Independent Supply Decision Review Mandate

Navigant was asked to review the reasonableness of:

- The long-term Island supply options considered by Nalcor
- Nalcor's assumptions associated with Island supply options, and
- The process followed to screen and evaluate the supply options.

Based on this review, Navigant was to provide an opinion on:

- Whether the Interconnected Island alternative represents the least cost option that also fulfills the additional criteria requirements of security of supply and reliability, environmental responsibility, and risk and uncertainty, and
- The accuracy of the rate projections.

Navigant's Conclusions

Based on its independent review, Navigant has concluded that the Interconnected Island alternative is the long-term least cost option for the Island of Newfoundland. Relative to the Isolated Island alternative, the Interconnected Island alternative is also expected to provide similar levels of security and reliability, significantly reduced greenhouse gas (GHG) emissions and significantly less risk and uncertainty. The Interconnected Island alternative also provides a gradual decrease in real (adjusted for inflation) average wholesale electricity rates for the Island.

Navigant has concluded that Nalcor's consideration and screening of the supply options as well as the assumptions used by Nalcor regarding these options were reasonable and consistent with generally accepted utility practices. Nalcor's process to evaluate the supply options and estimate the rate projections under the two alternatives was also found to be reasonable and consistent with generally accepted utility practices.

Navigant has concluded that the CPW calculated by Nalcor for each of the generation expansion alternatives fairly represent the costs that would be incurred under the alternative supply futures. Thus, the $2.2 billion preference for the Interconnected Island alternative, as estimated by Nalcor in the DG2 decision gate, is a reasonable estimate of the expected cost difference between the two alternatives.

To explore the sensitivity of the CPW difference between the two alternatives to changes in the supply options or assumptions, Nalcor and Navigant analyzed a number of sensitivity cases covering:

- different fuel price forecasts
- lower load growth
- additional wind generation
- introduction of carbon pricing
- aggressive CDM, and
- higher capital costs and the recently announced Federal Loan Guarantee for Muskrat Falls and the LIL.

All of the sensitivity cases resulted in a CPW advantage for the Interconnected Island alternative. This clearly indicates that the DG2 decision preference for the Interconnected Island alternative was robust given the underlying risk and uncertainty in key assumptions.

Key Findings

1. Nalcor's Gateway Process is a rigorous means of providing quality assurance for key decisions at crucial points in a project's lifecycle and is consistent with best practices.

2. The level and accuracy of the information used in Nalcor's DG2 Island Supply Decision was appropriate for the decision stage.

3. The 50 year generation expansion analysis period used by Nalcor was appropriate given the long-lived supply options being analyzed.

4. Nalcor appropriately included Muskrat Falls in Labrador and Island Pond, Portland Creek and Round Pond on the Island as hydroelectric generation in their generation expansion alternatives.

5. Nalcor appropriately excluded Gull Island in the Interconnected Island alternative because the purchase price for power from Gull Island would have to be 60 percent higher than power from Muskrat Falls under the same pricing framework.

6. Nalcor appropriately excluded other potential hydroelectric facilities in both generation expansion alternatives because the expected cost of power from other potential hydroelectric facilities would be approximately 20 percent higher than wind power.

7. Nalcor's exploration and analysis of alternatives for the LIL was rigorous and the transmission options developed and considered by Nalcor were reasonable.

8. LIL will be implemented using proven and reliable HVdc technology.

9. Nalcor's rejection of deferring the in-service date of the link until 2041 and using Churchill Falls as a supply option for the Island was reasonable given the higher costs and greater risks as compared to the Interconnected Island alternative.

10. Wind power is expected to be the lowest cost of the other renewable electricity supply options on the Island and Nalcor's inclusion of wind power in the Isolated Island alternative was reasonable.

11. Provided the power system constraints identified in the 2004 wind integration study can be addressed cost-effectively, Nalcor's Isolated Island alternative could consider 100 MW of additional wind power in 2025 and a further 100 MW in 2035 when it would be potentially expected to displace fossil fuel-fired generation most of the time.

12. No amount of wind generation could eliminate the need for the firm capacity provided by Holyrood or any replacement thermal facilities given the limited and uncertain capacity of wind generation.

13. Nalcor would have the capacity to integrate significantly more than 200 MW of wind only in the Interconnected Island alternative given the performance characteristics of Muskrat Falls.

14. Nalcor appropriately excluded biomass from both generation expansion alternatives because of the relatively limited biomass accessible through NL's existing forestry infrastructure.

15. Nalcor appropriately excluded solar photovoltaic (PV) generation in both generation expansion alternatives because of Newfoundland's low insolation rates and the cost of power from solar PV installations.

16. Nalcor appropriately excluded wave and tidal generation in both generation expansion alternatives because of its unproven commercial viability.

17. Nalcor appropriately included the continuation of oil-fired generation in both generation expansion alternatives because it is a proven resource in the Island's generation supply mix.

18. Nalcor appropriately excluded natural gas generation in both generation expansion alternatives because natural gas is not commercially available on the Island and there are, as yet, no firm development plans to bring natural gas to the Island.

19. Nalcor appropriately excluded liquefied natural gas (LNG) generation in both generation expansion alternatives because there is no clear economic advantage to using LNG given the required capital for LNG-related facilities, coupled with the linkage of long term LNG pricing to oil.

20. Nalcor appropriately excluded coal-fired generation in both generation expansion alternatives because of its significant environmental risks.

21. Nalcor appropriately excluded nuclear generation in both generation expansion alternatives because of provincial legislation, project capital costs and risk factors.

22. Nalcor's forecast methodology is consistent with generally accepted utility practice and the base forecast for demand and energy growth is reasonable.

23. Absent new supply, the Island will experience a capacity deficit in 2015 and an energy deficit in the 2020 timeframe

24. Nalcor could consider the impact of a longer term CDM initiative.

25. Nalcor's risk assessment analysis for Muskrat Falls and the Labrador-Island Link project was thorough and comprehensive.

26. Nalcor's focus on time, tactical and strategic risks for the Muskrat Falls and Labrador-Island Link is consistent with best practices and provides a high level of confidence in the integrity of capital cost estimates.

27. Nalcor's estimated capital costs and escalation methodology for the various supply options considered in the two generation expansion alternatives was reasonable.

28. The fuel cost forecast used by Nalcor in its analysis of the generation expansion alternatives was reasonable.

29. The heat rates, operating and maintenance costs, operating lives, projected retirements, and outage rates used by Nalcor in its analysis of the generation expansion alternatives were reasonable.

30. Nalcor could consider how future environmental legislation, such as limits on the unit emission rates for fossil-fuel fired generation that could force the closure of Holyrood or the introduction of carbon pricing that would increase thermal production costs, would affect its supply alternatives.

31. The Muskrat Falls pricing approach used by Nalcor was appropriate and sufficiently well defined for the purposes of 1) estimating the Muskrat Falls power purchase price, and 2) informing the DG2 decision.

32. Nalcor's use of the Strategist model in developing the two generation expansion alternatives is consistent with generally accepted utility practice.

33. The CPWs for the generation expansion alternatives fairly represent the costs that would be incurred under the alternative supply futures. Therefore, the $2.2 billion CPW preference for the Interconnected Island alternative is a reasonable estimate of the expected cost difference between the two alternatives.

34. The sensitivity cases run by Nalcor and Navigant capture the key risks in the assumptions for, and the impacts of potential refinements to, the generation expansion alternatives.

35. All of the sensitivity cases maintained the CPW preference for the Interconnected Island alternative. This clearly indicates that the DG2 decision preference for the Interconnected Island alternative was robust given the underlying risk and uncertainty in key assumptions in the generation expansion alternatives.

36. The CPW preference for the Interconnected Island alternative is maintained after adding more wind or CDM to the Isolated Island alternative.

37. Current information, and specifically the updated May 2011 PIRA long term fuel forecast and the recently announced federal loan guarantee commitment, increases the CPW preference for the Interconnected Island alternative.

38. Relative to the Isolated Island alternative, the Interconnected Island alternative is also expected to provide similar levels of security and reliability, significantly reduced GHG emissions and significantly less risk and uncertainty.

39. The criteria used by Nalcor in the Island supply decision were reasonable and consistent with generally accepted utility practices.

40. The Interconnected Island alternative represents a fundamental change to a more stable and certain utility cost structure for the Island by minimizing thermal generation and its associated fuel cost uncertainty.

41. Nalcor's wholesale electricity rate impact analysis accurately reflects the rate projections and provides a reasonable basis for assessing unit cost trends with respect to the two alternatives.

42. Short-term increases in real (before considering inflation) wholesale electricity rates would occur over the next few years under either alternative. Beyond 2017, the wholesale electricity rates for the Interconnected Island alternative decline in real terms.

43. Wholesale electricity rates are lower in the Interconnected Island alternative than the Isolated Island alternative except for a brief period at the end of this decade. This short-term issue could be mitigated through ratemaking.

1 INTRODUCTION

Nalcor's Gateway Process is designed to ensure decisions are made at appropriate times, with the appropriate level of information, and at appropriate levels of expenditure. Nalcor's Gateway Process focuses on key milestones to achieve gateway readiness and builds in "cold eyes" reviews at key decision points throughout the process.

The Lower Churchill Project Phase I has passed through Decision Gate 2 (DG2) which is Concept Selection. At that time, to select a preferred concept, Nalcor completed the appropriate activities and gathered the required information including field work, engineering and design, finalization of Labrador Innu Impacts and Benefits Agreement (IBA), environmental assessment progression, execution of water management agreement, completion of the Emera Term Sheet, financing preparation and economic analysis.

Decision Gate 3 (DG3) which is Project Sanction requires the advancement of project activities and work streams to a level of progression which provides the certainty needed to sanction the Project (e.g. ratification of the IBA, receipt of environmental permits and approvals, completion of detailed engineering and design, market confirmation of financing strategy, finalization of definitive commercial agreements, etc.). The intent of DG3 is to validate the concept selected before committing the largest dollars.

Independent reviews are carried out in accordance with established Nalcor decision-making processes with each Decision Gate. Nalcor has retained Navigant to conduct an initial review using DG2 estimates. This report presents Navigant's findings related to Nalcor's recent DG2 decision. Navigant will provide a second report using DG3 project cost and schedule information as input to the DG3 decision.

1.1 Newfoundland Electricity System

Newfoundland's electrical system is isolated with no connection to any other electrical system. This section describes the utilities, the generation, the transmission, and the load on the Island.

Island Utilities

Two regulated electric utilities serve the Island: Newfoundland and Labrador Hydro (NL Hydro) and Newfoundland Power. The utilities operate under the jurisdiction of the Board of Commissioners of Public Utilities of Newfoundland & Labrador (PUB) which has regulatory authority over rates, policies, capital expenditures and the issue of securities.

- **NL Hydro**[1] is a crown-owned electric utility which owns and operates facilities for the generation, transmission and distribution of electricity to utility, industrial and retail

[1] NL Hydro is a subsidiary of Nalcor. This report will use the term "Nalcor" both in reference to the parent company and the subsidiary unless there is a direct reference to NL Hydro.

customers in the Province of Newfoundland and Labrador. It is primarily a wholesale and transmission utility, and Newfoundland Power is its largest customer.

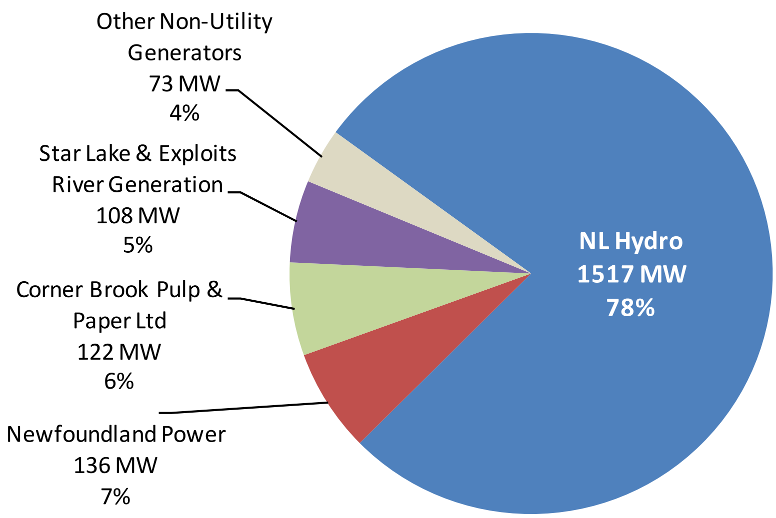
NL Hydro directly serves over 35,000 residential customers in 220 communities across the province. NL Hydro also operates 22 diesel systems to provide service to 4,300 customers in isolated communities throughout coastal areas of Newfoundland & Labrador. NL Hydro also sells power to three regulated industrial customers on the Island.

- **Newfoundland Power**, an investor-owned company, is primarily a distribution utility that sells electricity to approximately 86 percent, or over 240,000, of the retail customers on the Island interconnected system. The Company generates approximately 7 percent of its electricity needs and purchases the remainder from NL Hydro.

Generation

As shown in Figure 1, the Island electricity system has a total generating capacity of 1,956 MW. Most of this capacity (78 percent) is operated by NL Hydro, with the remainder operated by Newfoundland Power, Corner Brook Pulp & Paper, Star Lake & Exploits River Generation, and non-utility generators (NUGs). NUGs include 54 MW of wind, which is sold to NL Hydro.

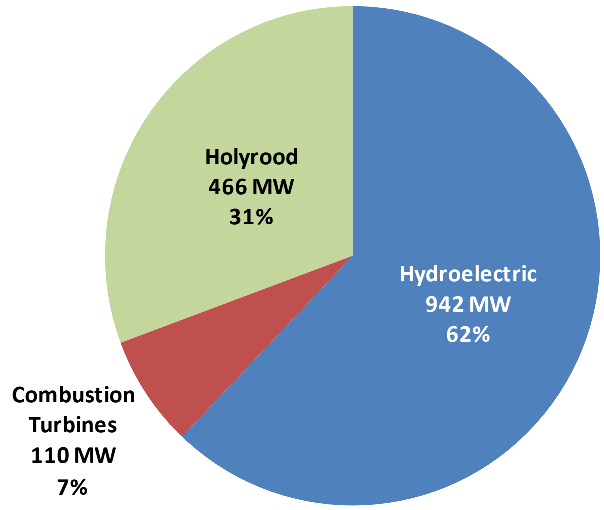
Figure 1: Newfoundland Generation Capacity by Operator (MW)



Source: Nalcor. "Synopsis of 2010 Generation Expansion Decision" Exhibit 13b. July 2011.

As shown in Figure 2, the majority of NL Hydro's generation capacity is hydroelectric, followed by the oil-fired Holyrood plant and oil-fired combustion turbines. The Holyrood plant Units 1 and 2 came on line in 1971, Unit 3 came on line in 1979.

Figure 2: NL Hydro Net[2] Generating Capacity (MW)



Source: Nalcor. "Synopsis of 2010 Generation Expansion Decision" Exhibit 13b. July 2011.

Transmission

Figure 3 illustrates the Newfoundland and Labrador transmission system. The 230 kV transmission system east of Bay d'Espoir has a transfer limit of 365 MVA in the summer and 509 MVA in the winter. The existing transmission system is operating near full capacity and efficient scheduling of existing hydroelectric and thermal generation is at times a challenge. Approximately 67 percent of the Island demand is located east of Bay d'Espoir.[3] This, coupled with transmission constraints noted above, creates voltage support requirements on the eastern part of the Island.

[2] Net of station service load

[3] "Nalcor Response to Panel Information Request March 21, 2011." April 1, 2011.

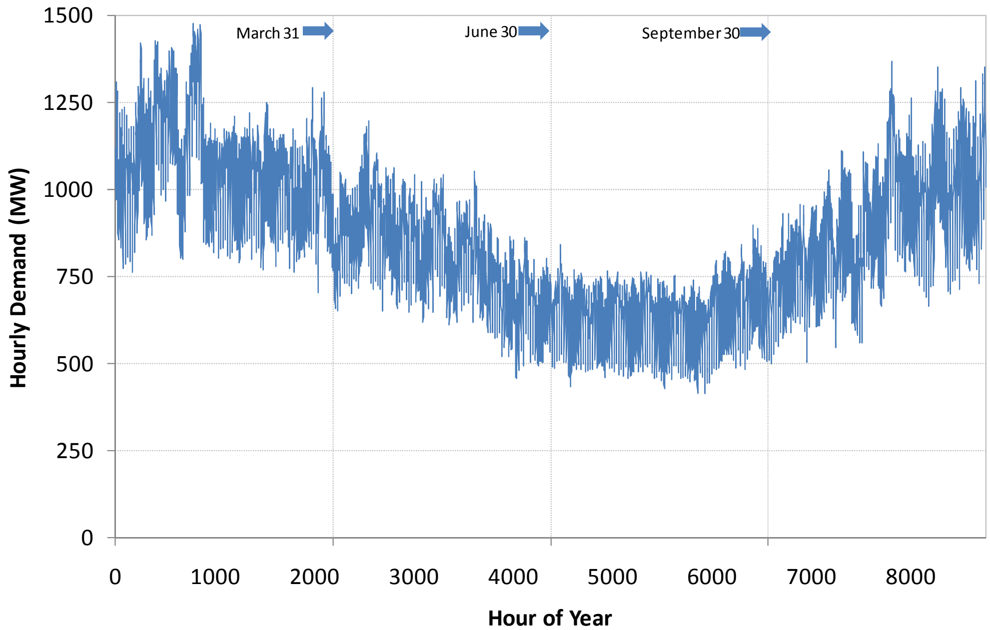
Figure 3: Newfoundland and Labrador Transmission

Source: NL Hydro System Planning Department 2011.

Load

In 2010, the Island electricity system had a peak demand of 1,478 MW and an energy requirement of 7,355 GWh. Figure 4 presents Island hourly demand for 2010, showing substantially higher winter energy use.

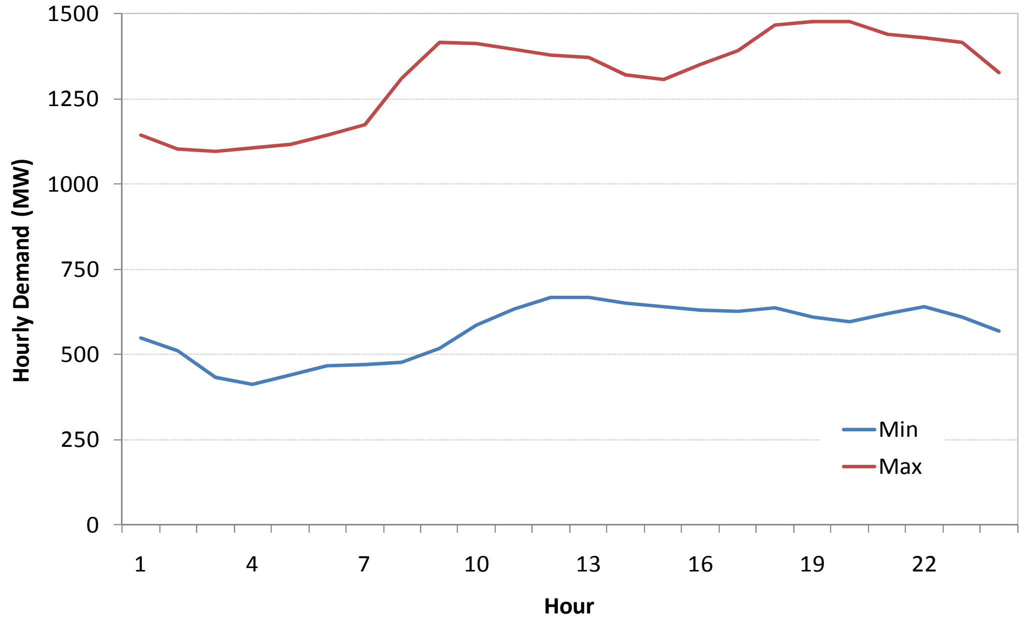
Figure 4: Island Hourly Demand, 2010



Source: Nalcor

Electricity demand is typically highest during the evenings in colder winter months. NL Hydro defines the peak period as the morning period from 7:00 a.m. to noon and the evening period from 4:00 to 8:00 p.m. during the four coldest months of December to March. As shown in Figure 5, peak day use is over twice as high as lowest day use.

Figure 5: Minimum and Maximum Island Daily Demand, 2010



Source: Nalcor and Navigant Analysis

1.2 Options for Meeting Island Supply

Nalcor evaluated a number of generation expansion alternatives for the long-term supply of electricity to the Island of Newfoundland. The alternatives fell into two broad categories: 1) Isolated Island alternatives, and 2) Interconnected Island alternatives. Based on the DG2 estimates, the optimal generation expansion plan in each of these two categories is described below.

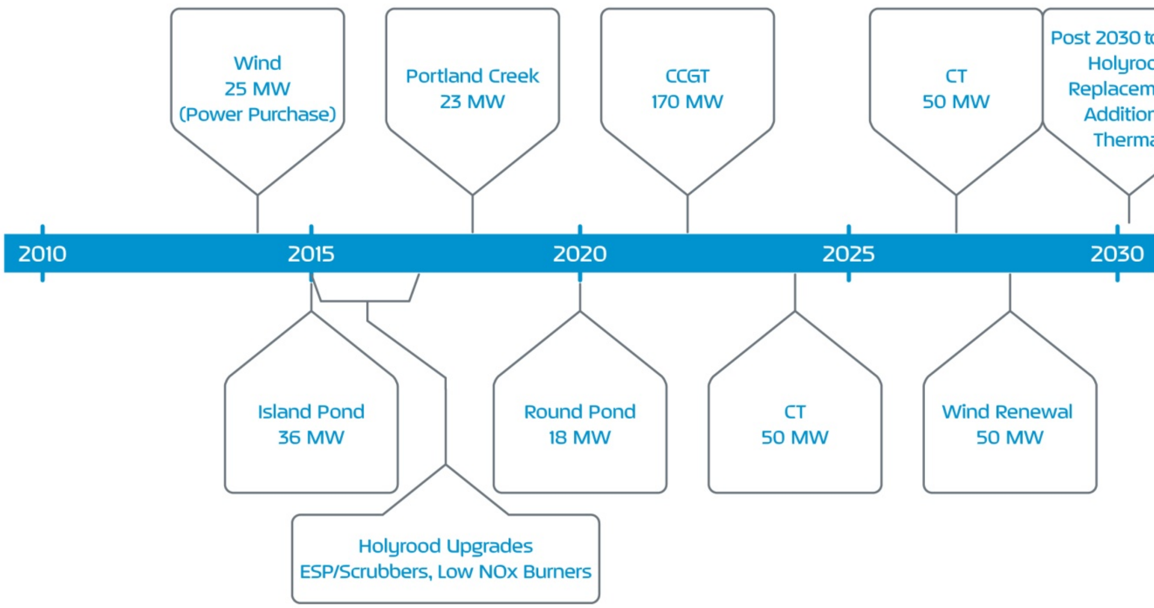
The outcome of the generation planning analysis is a metric called Cumulative Present Worth (CPW), which is the present value of all incremental utility capital and operating costs incurred by the utility to reliably meet a specific load forecast given a prescribed set of reliability criteria. Where one alternative cost future for the grid has a lower CPW than another alternative supply future, the option with the lower CPW will be preferred by the utility, consistent with the provision of mandated least cost electricity services. From a financial planning perspective, the supply future with the lowest CPW will translate into the lowest overall revenue requirements.

Nalcor used the Ventyx Strategist utility planning software tool to identify the optimal generation expansion plan for each alternative. Further details regarding the Strategist tool are provided in Section 4.

1.2.1 Isolated Island Generation Expansion Plan

The key elements of the Isolated Island alternative are the development of limited renewable resources in the near-term, pollution abatement, life extension improvements at the Holyrood plant, replacement of the Holyrood plant and the continued development of thermal power resources across the planning period 2010 to 2067 as shown in Figure 6. This alternative would entail continued isolation of the Island power grid and the inherent supply and operational limitations associated with isolation.

Figure 6: Isolated Island Generation Expansion Plan



Source: Nalcor Energy

1.2.2 Interconnected Island Generation Expansion Plan

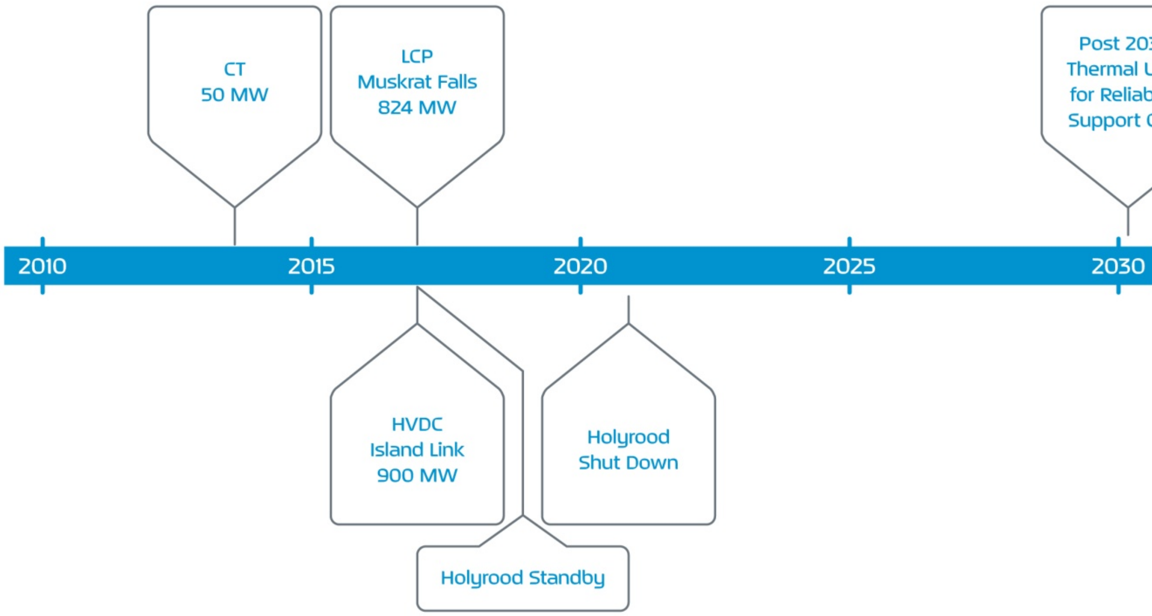
The Churchill River in Labrador is a source of renewable, clean electrical energy; however, the potential of this river has yet to be fully developed. The existing 5,428 MW Churchill Falls generating station, which began producing power in 1971, harnesses about 65 per cent of the potential generating capacity of the river. The remaining 35 per cent is located at two sites on the lower Churchill River, known as the Lower Churchill Project (LCP).

The LCP's two proposed installations, Gull Island and Muskrat Falls, would have a combined capacity of 3,074 MW with annual output of 16.7 Terawatt hours of electricity per year. That is enough to supply hundreds of thousands of households annually and contribute significantly to the reduction of air emissions from fossil fuel-fired power generation.

The Interconnected Island alternative would include two major new facilities: the 824 MW Muskrat Falls generation facility and the 1,100 km High Voltage direct current (HVdc) Labrador - Island Transmission Link (LIL) from Muskrat Falls to the Avalon Peninsula. This alternative would provide the capability to displace the Holyrood plant and meet the growth in provincial power requirements for years to come. In addition, this alternative would interconnect the

Island with the regional North American power grid. The major components of the Interconnected Island alternative are presented in Figure 7.

Figure 7: Interconnected Island Generation Expansion Plan



Source: Nalcor Energy

1.3 Scope of the Independent Supply Decision Review

Nalcor charged Navigant with reviewing the reasonableness of:

- The long-term Island supply options considered by Nalcor
- Nalcor's assumptions associated with Island supply options, and
- The process followed to screen and evaluate the supply options.

Based on this review, Navigant was to provide an opinion on:

- Whether the Interconnected Island alternative represents the least cost Island supply option that also fulfills the additional criteria requirements of security of supply and reliability, environmental responsibility, and risk and uncertainty, and
- The accuracy of the rate projections.

The inputs for Navigant's review include:

- All necessary financial and engineering models, reports, and discussions with management and personnel
- The 2007 Energy Plan (available at www.nr.gov.nl.ca/nr/energy/plan/) that forms the policy framework used by Nalcor in determining the Island supply option

- The Island supply option evaluation criteria used by Nalcor, and
- Generally accepted utility practices for the evaluation of Island supply options.

The Island supply option evaluation criteria that Nalcor asked Navigant to consider were:

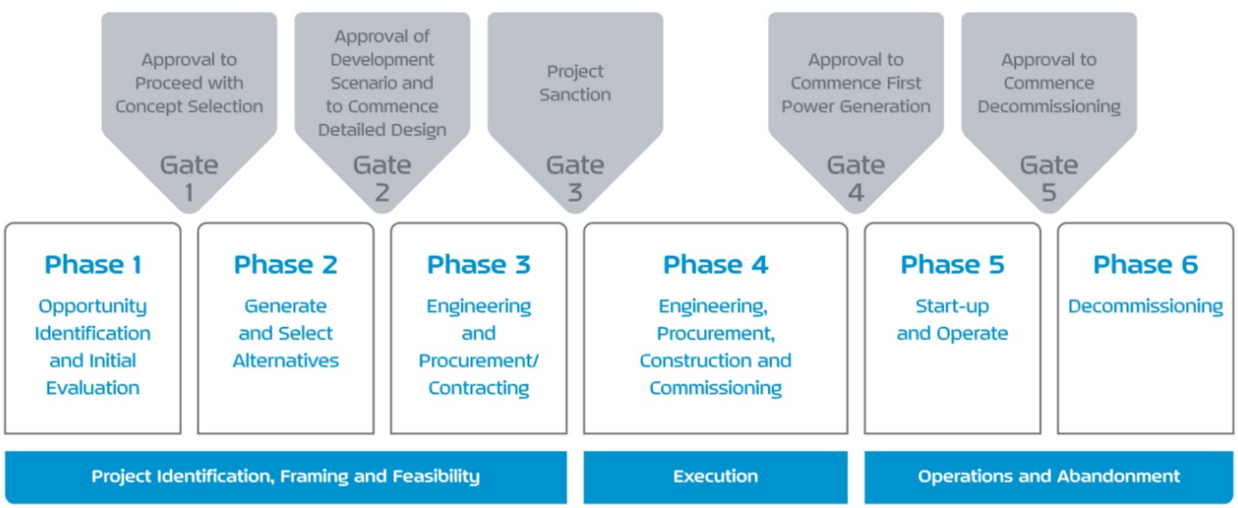
- Security of supply and reliability
- Cost to ratepayers
- Environmental responsibility, and
- Risk and uncertainty.

A review of the financing decision for Muskrat Falls or the monetization of any excess power from Muskrat Falls beyond the commitment for Muskrat Falls power assumed in the Interconnected Island alternative was beyond the scope. Therefore, Navigant's Independent Supply Decision Review did not extend to the financial viability of non-regulated assets.

Nalcor's Gateway Process

Nalcor's Gateway Process, illustrated in Figure 8, is a staged or phased decision gate assurance process that is used to guide the planning and execution of the Project from identifying the opportunity through determining how it should be developed (e.g. transmission access, plant capacity, etc.), obtaining project approvals, completing engineering and commencing construction. It serves as a means of quality assurance for key decisions at crucial points in a project's lifecycle.

Figure 8: Nalcor's Gateway Process



As indicated, the LCP has passed through Decision Gate 2 (DG2). DG2 is of strategic importance to the LCP as it signifies that the development scenario, including phasing and sequencing, and that Nalcor is ready to move forward with detailed engineering and procurement / contracting and prepare to commence early construction works following release from environmental assessment. During Phase 3, engineering will progress to a level of completeness required to facilitate the award of key construction and supply contracts required to maintain the overall project schedule as well as provide the level of cost and schedule certainty for Decision Gate 3 (DG3).

Nalcor asked Navigant to provide an opinion on:

1. The reasonableness of the process and decision based on the DG2 estimates and other information available at the time of the DG2 decision, and
2. Whether current information impacts the reasonableness of the DG2 decision.

Navigant will provide a second independent report using DG3 estimates and assumptions prior to the DG3 decision.

Navigant's key findings with respect to the Nalcor's Gateway Process and the level and accuracy of information considered by Nalcor in the DG2 Island Supply Decision are summarized below:

1. Nalcor's Gateway Process is a rigorous means of providing quality assurance for key decisions at crucial points in a project's lifecycle and is consistent with best practices.

2. The level and accuracy of the information used in Nalcor's DG2 Island Supply Decision was appropriate for the decision stage.

3. The 50 year generation expansion analysis period used by Nalcor was appropriate given the long-lived supply options being analyzed.

1.4 Navigant's Approach and Structure of Report

Figure 9 provides an overview of Navigant's approach to the independent supply decision review.

Figure 9: Overview of Navigant's Approach

1. Understand current situation / system requirements

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2. Review supply options considered

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3. Review assumptions for supply options

↓

4. Review process to evaluate supply options

↓

5. Review results / explore sensitivity cases

↓

6. Review accuracy of rate impact analysis

↓

7. Provide key findings and conclusions

The structure of this report reflects Navigant's approach.

2 Consideration and Screening of Island Supply Options

This section presents Navigant's assessment of the reasonableness of the supply options considered and screened by Nalcor in the Island supply decision. The specific options covered in this section are:

1. Hydroelectric
2. Transmission Interconnection with Labrador
3. Other Renewables
4. Fossil, and
5. Nuclear.

2.1 Hydroelectric

The hydroelectric generation options included by Nalcor in the analysis were:

- Muskrat Falls in Labrador, and
- Island Pond, Portland Creek and Round Pond on the Island.

The cost and performance characteristics of these projects are relatively firm based on engineering estimates and feasibility studies. Their inclusion as options in the analysis is appropriate.

Nalcor also considered other hydroelectric generation options in its analysis. These other options are discussed below.

Gull Island

As the Island requirements represent a much lower proportion of the Gull Island output and in the absence of confirmed export transmission via Quebec or new, large industrial load in Labrador, the financial returns for the Gull Island project selling only to the Island would be unacceptably low and the project would likely not be supported in capital markets. In order to provide the same rate of return as projected for the Muskrat Falls project in the DG2 decision, the purchase price for power from Gull Island would have to be approximately 60 percent higher than power from Muskrat Falls.

Other Small Hydroelectric

There are other potential hydroelectric generation sites on the Island. In a 1986 study, Shawmont Newfoundland (Shawmont) identified 196 potential sites with capacities between 1 – 20 MW.

Of 11 proposals submitted in response to a 1992/93 small hydroelectric procurement, Nalcor selected the four proposals with the lowest bid prices. The seven proposals that were not selected had an average bid price of approximately $67 per MWh (1993$). In 2010$, this bid price is approximately $102 per MWh[4], exclusive of transmission interconnection costs. Note that this price should not be extended to other potential small hydroelectric facilities on the Island that developers did not put forward. This small hydroelectric price is approximately 20 percent higher than the projected price for wind generation as described in section 2.3.1. Given this cost differential and the ubiquitous wind resource on the Island, Navigant believes that it was reasonable for Nalcor to exclude other potential hydroelectric facilities in its generation expansion alternatives.

Even if this potential resource was economically attractive, NL Hydro's transmission system does not currently have sufficient capacity to collect and transmit significantly more electricity from west of the Avalon Peninsula to the Island's load centre on the Avalon Peninsula.

However, NL Hydro is planning a new 230 kV circuit from Bay D'Espoir to the Avalon Peninsula with construction to begin in 2012. This new circuit is common to both alternatives; in the Interconnected Island alternative it ensures system stability and in the Isolated Island alternative it provides additional transmission capacity to integrate renewable resources located off the Avalon Peninsula. After the completion of the transmission upgrades, NL Hydro expects to have sufficient capacity to transmit the output of the three new hydroelectric plants plus approximately 100 MW to the Avalon Peninsula in the Isolated Island alternative.

4. Nalcor appropriately included Muskrat Falls in Labrador and Island Pond, Portland Creek and Round Pond on the Island as hydroelectric generation in their generation expansion alternatives.

5. Nalcor appropriately excluded Gull Island in the Interconnected Island alternative because the purchase price for power from Gull Island would have to be 60 percent higher than power from Muskrat Falls under the same pricing framework.

[4] 1993 average bid price of $67 per MWh for unselected bids has been escalated to 2010$ using the NL Hydro's annual capital cost escalation index for hydraulic plant construction from 1993 through 2010. The escalated price was calculated as follows:

2010$ price = $67 per MWh x (1.025)^(2010 -1993)
= $67 per MWh x 1.519
= $102 per MWh

6. Nalcor appropriately excluded other potential hydroelectric facilities in both generation expansion alternatives because the expected cost of power from other potential hydroelectric facilities would be approximately 20 percent higher than wind power.

2.2 Transmission Interconnection

The 1,100 km HVdc Labrador-Island Link (LIL) would provide 900 MW of power transfer capacity between Labrador and the Island and was the recommended option to serve the Island in the Interconnected Island alternative[5]. The long distance, water crossing and weakness of the Island electrical system make HVdc technology the only technically feasible option.

LIL will be implemented using proven and reliable HVdc technology. Commercial application of HVdc started in the 1950's and since then, HVdc has become a mature and reliable technology offering advantages for long distance power transfer. Through 2005, almost 80,000 MW of HVdc transmission capacity has been installed worldwide[6]. Many of these projects have been operating reliably for more than 25 years and, like the proposed LIL, traverse long distances. One good example is the 1,360 km, 400 kV, 1,440 MW Pacific Intertie developed by ABB which began operation in 1970. Another example is the 1,480 km, 450 kV, 2,000 MW Quebec to New England HVdc link which began operation in 1992. Additional HVdc projects are listed in the table below.

Figure 10: Illustrative List of HVdc Facilities Currently in Operation

PROJECT	LOCATION	DISTANCE (km)	POWER (MW)	VOLTAGE (kV)
Yunnan	China	1,418	5,000	800
Ballia Bhiwadi	India	800	2,500	500
Talcher Kola	India	1,450	2,500	500
Guizhu Guangdong	China	980	3,000	500
Guizhu Guangdong II	China	1,225	3,000	500
Nelson River	Canada	900	900	450
East South Interconnect	India	1,450	2,000	500
Gezhouba Nan Qiao	China	1,000	1,200	500
Cahora Bassa	South Africa	1,456	1,920	533

[5] "Synopsis of 2010 Generation Expansion Decision", July 6, 2011.

[6] Cigre WG B4-04 2003 -IEEE T&D Committee 2006

Submarine HVdc is also a proven and reliable transmission technology. The Gotland HVdc system was commissioned in 1954. The first submarine cable across the Cook Strait in New Zealand was added in 1965. ABB installed a 200 km, 400 kV, 500 MW Fenno – Skan submarine HVdc cable in 1989.

Nalcor also considered a number of other alternative transmission supply options for the Interconnected Island alternative in an effort to reduce the length of the HVdc link, all of which required reinforcement of the existing AC system. However, given the existing AC transmission system on Newfoundland, supplying 900 MW of power transfer capacity solely through AC system reinforcement would require at least four new 230kV transmission lines or two new 345kV lines. All of these alternatives were more expensive and involved more line-km of construction than the LIL.

Nalcor explored deferring the in-service date of the link until 2041 when the current Churchill Falls contract ends and using Churchill Falls as a supply option for the Island. Nalcor rejected this interconnection alternative for a number of reasons as summarized below:

- It would result in significantly higher costs to Island ratepayers as compared to the Interconnected Island alternative (this is discussed in greater detail in section 5.2)
- Island ratepayers would be exposed to fuel price volatility and Nalcor would be exposed to potential environmental legislation compliance risks affecting thermal production (see section 3.3.8) in the period through 2041, and
- Given that Nalcor is not the sole shareholder of the Churchill Falls facility, there is uncertainty around terms for availability of supply from Churchill Falls.

Nalcor also explored a pure import alternative via a transmission link from Newfoundland to Atlantic Canada and New England for the purposes of accessing power and energy to meet the Island's electricity requirements. Like the deferred interconnection, this option was rejected by Nalcor as it would result in significantly higher costs to Island ratepayers as compared to the Interconnected Island alternative and potential security of supply risks given the challenges of securing firm supply over the long-term. This is discussed in greater detail in section 5.2.

7. **Nalcor's exploration and analysis of alternatives for the LIL was rigorous and the transmission options developed and considered by Nalcor were reasonable.**

8. **LIL will be implemented using proven and reliable HVdc technology.**

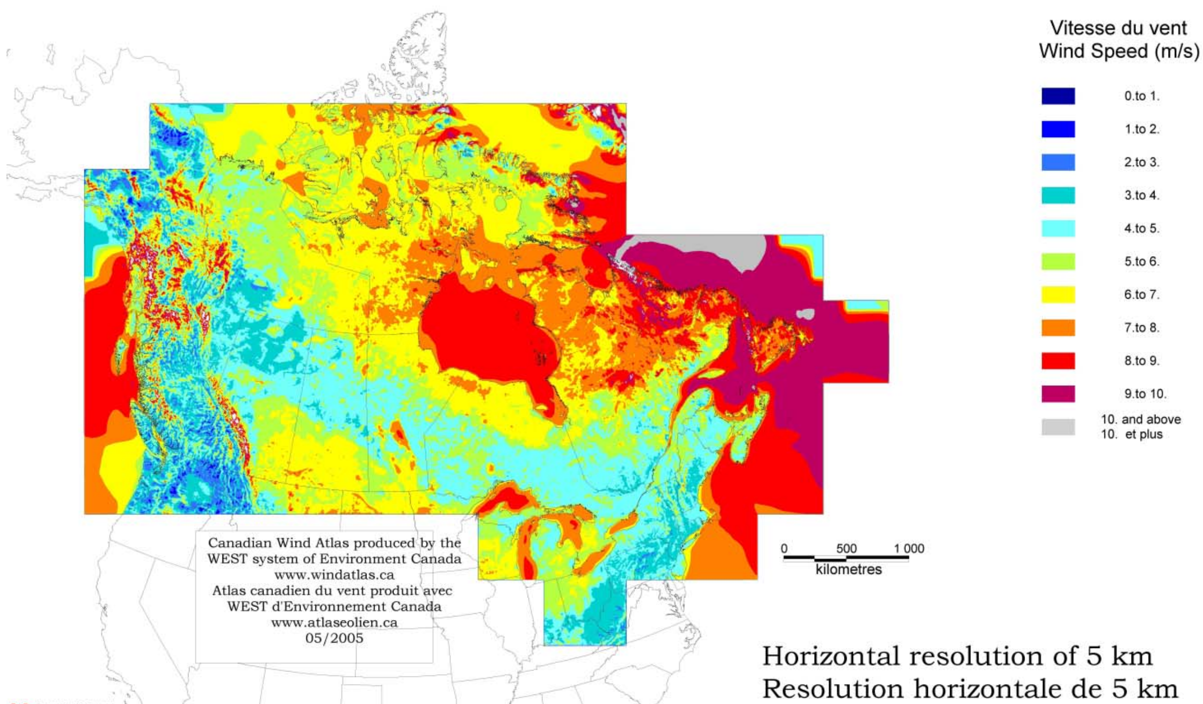
> **9. Nalcor's rejection of deferring the in-service date of the link until 2041 and using Churchill Falls as a supply option for the Island was reasonable given the higher costs and greater risks as compared to the Interconnected Island alternative.**

2.3 Other Renewables

2.3.1 Wind

Newfoundland has abundant wind resources as shown in Figure 11. Nalcor included a 25 MW wind addition in 2014 in the Isolated Island alternative and, given the expected 20 year life of wind generation facilities, renewal in 2034 and again in 2054. The Isolated Island alternative also includes renewal of the 54 MW of existing Island wind generation in 2028 and again in 2048.

Figure 11: Wind Map of Canada (mean wind speed 50 m above ground)



Source: Environment Canada. http://www.windatlas.ca/en/EU_50m_national.pdf.

NL Hydro conducted a study in 2004 assessing non-dispatchable wind generation as an alternative to fossil based generation[7]. The study found:

- Additional amounts of non-dispatchable wind generation up to 80 MW may be incorporated into the system with little risk of additional spill, and
- Amounts of non-dispatchable wind generation up to 130 MW may be integrated into the system as a whole without significant technical performance repercussions.

Assuming sufficient transmission capacity for additional wind facilities beyond those in the Isolated Island alternative was available, incremental wind production would not necessarily displace fossil-fuel fired thermal output at all times of the year. During some times of the year, incremental wind production would increase the probability of spill at existing hydroelectric facilities. NL Hydro estimates that load growth sufficient to potentially enable approximately 100 MW of incremental wind output to displace thermal output would not occur until approximately 2025 in the Isolated Island alternative.

Forecast load growth in the 2025 to 2035 time frame would potentially require additional thermal output which would enable up to 100 MW more wind power to be added in 2035 (again subject to the constraint of displacing thermal output at almost all times).

Given this potential for limited additional amounts of renewable output to displace thermal output starting in approximately 2025 based on projected load growth, Navigant believes that Nalcor could consider adding 100 MW of wind power in the Isolated Island alternative starting in 2025, plus another 100 MW of wind power in 2035, provided that the wind capacity system constraints in the 2004 study can be addressed cost-effectively.

Navigant believes that this incremental 200 MW of wind power by 2035 should be considered as an upper limit. Higher amounts of wind power would either require:

- Reducing the number of other generating units on-line at any one time (which may cause system stability problems), or
- Curtailing wind output which would increase the supply price for wind power to ensure wind developers are able to earn their required revenue during those periods when they are not curtailed. For example, assume a wind developer bid $100 per MWh under contract without any curtailment. If they were going to be curtailed 33 percent of the time, they would have to make up their desired annual revenue from only 67 percent of the maximum possible output. As such their required price would increase to $150 per MWh to realize the same annual revenue.

[7] Newfoundland and Labrador Hydro. "An Assessment of the Limitations for Non-Dispatchable Generation on the Newfoundland Island System." 2004

System production forecast information from Nalcor suggests that any significant amounts of wind generation beyond the 200 MW limit would have to be curtailed for at least four months of the year during the summer when NL Hydro's thermal production is at its lowest level.

Based on NL Hydro's projected cost of the 25 MW wind project planned for the Isolated Island alternative starting in 2014, Navigant estimates that the first year cost of wind power (assuming no curtailments) under a similar contract structure would be $86 per MWh (2010$)[8] and would escalate as per Nalcor's current wind contracts.

To explore the impact of additional wind power on the costs for the Isolated Island alternative, Nalcor and Navigant ran a sensitivity case with 100 MW of additional wind power in 2025, and a further 100 MW of wind power in 2035. Wind projects typically have a life of 20 years. Therefore, Navigant modeled two sets of wind projects. Based on the estimated first year contract price of $86 per MWh (2010$) as described above and assuming 2 percent annual capital cost escalation for wind projects, the estimated first year contract prices for the wind projects (in nominal $ for the first year and escalating during the remainder of their contract period at 25 percent of inflation) are as follows.

Table 1: Additional Wind Project Parameters

Wind Project	Start Year	Initial Contract Price (nominal $ per MWh)
Project 1	2025	116
Project 2	2035	142
Project 1 Replacement	2045	173
Project 2 Replacement	2055	211

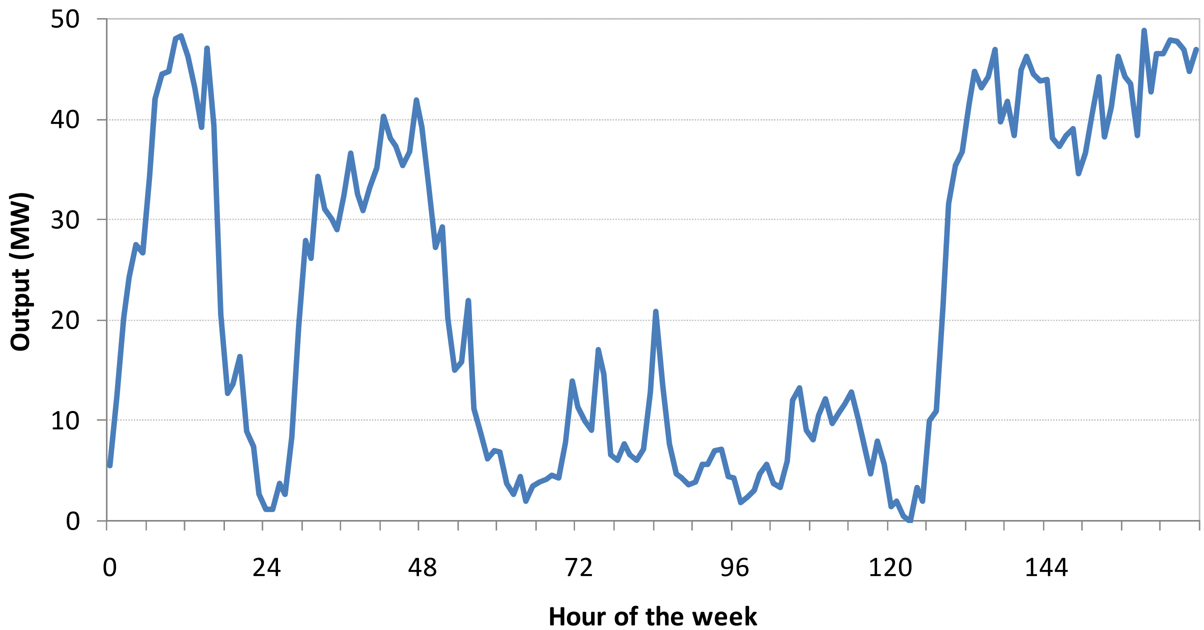
Navigant does not expect that 200 MW of incremental wind would eliminate the need for the peaking capacity of Holyrood and replacement thermal facilities. The aggregate output for a one week (168 hour) period in January 2010 from the two wind farms currently contracted with NL Hydro is shown in Figure 12. This chart highlights the variability of wind generation output and the uncertain contribution that wind generation provides to meeting system capacity requirements.

[8] Per "*Copy of Exhibit 6a PPA Listing and Rates (2).xls*", Nalcor estimates a first year contract price of $94 per MWh for a wind facility starting operation in 2014. Assuming 2 percent annual capital cost escalation from 2010 through 2014, the equivalent cost in 2010$ would be:

2010$ price = $94 per MWh (2014$) / [(1.02)^(2014 – 2010)]

= $86 per MWh (2010$)

Figure 12: Aggregate Newfoundland Wind Generation Output – January 2010



Source: Nalcor

Although the focus of the above analysis is on wind in the Isolated Island alternative, it is important to note that due to the wide operating range of the Kaplan turbines at Muskrat Falls and their fast production ramp rate, Nalcor would have the capacity to integrate significantly more than 200 MW of wind in the Interconnected Island alternative. This ability would be complemented by Nalcor's access to reservoir storage in Labrador and on the Island.

10. Wind power is expected to be the lowest cost of the other renewable electricity supply options on the Island and Nalcor's inclusion of wind power in the Isolated Island alternative was reasonable.

11. Provided the power system constraints identified in the 2004 wind integration study can be addressed cost-effectively, Nalcor's Isolated Island alternative could consider 100 MW of additional wind power in 2025 and a further 100 MW in 2035 when it would be potentially expected to displace fossil fuel-fired generation most of the time.

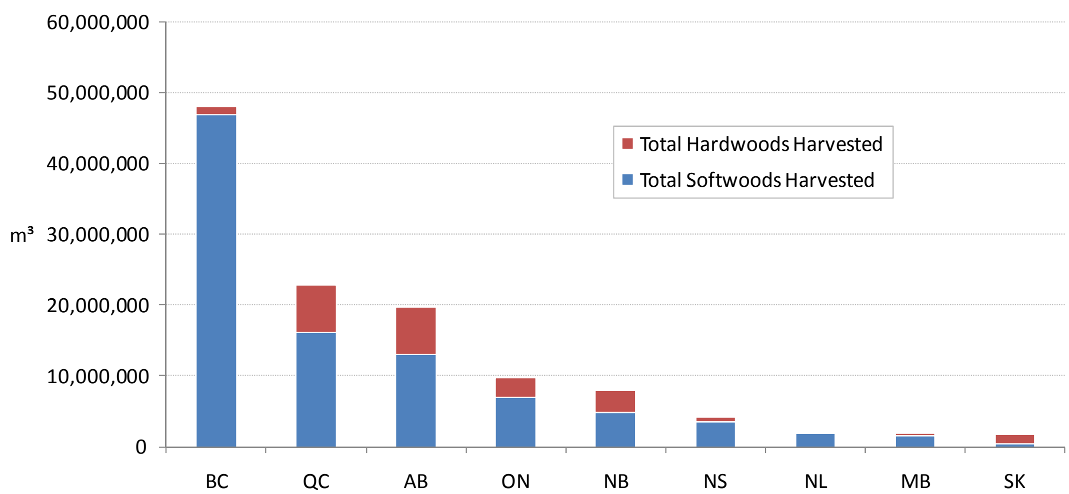
12. No amount of wind generation could eliminate the need for the firm capacity provided by Holyrood or any replacement thermal facilities given the limited and uncertain capacity of wind generation.

13. Nalcor would have the capacity to integrate significantly more than 200 MW of wind only in the Interconnected Island alternative given the performance characteristics of Muskrat Falls.

2.3.2 Biomass

Biomass is a relatively expensive form of electricity even where biomass resource availability and infrastructure to harvest the biomass resource are good. As shown in Figure 13, Newfoundland and Labrador (NL) ranks seventh amongst Canadian provinces in terms of total forestry harvest.

Figure 13: 2009 Forestry Harvest by Province



Source: National Forestry Registry. http://nfdp.ccfm.org/index_e.php. Accessed August 22, 2011.

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). Hence, it is not surprising that British Columbia, with the highest forestry harvest, also has the most electricity (1,711 GWh in 2009) produced from wood and spent pulping liquor of all Canadian provinces[9].

Based on recent Navigant work on several biomass projects, Navigant expects capital costs in the range of $3,500 per kW and variable fuel costs (including harvesting and transportation) would fall in the range of $50 - $100 (2010$) per MWh. Given these costs, Navigant estimates an all-in electricity cost (inclusive of capital recovery [depreciation, interest, debt service and equity return], fixed operating costs and variable fuel costs) in the range of $150 - $200 per MWh for NL.

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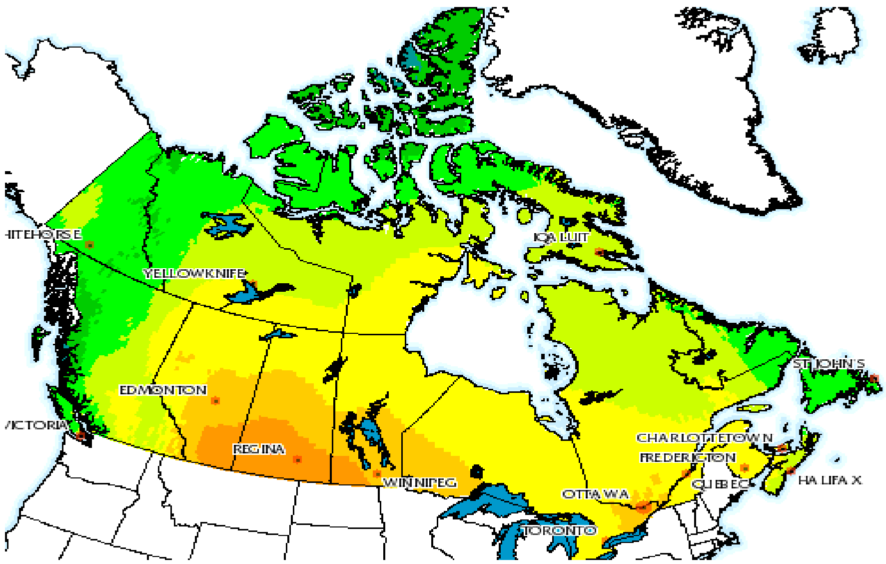
[9] Statistics Canada, Report on Energy Supply and Demand in Canada, 2009

14. Nalcor appropriately excluded biomass from both generation expansion alternatives because of the relatively limited biomass accessible through NL's existing forestry infrastructure.

2.3.3 Solar

Newfoundland's high latitude (49° N) and cloudy conditions cause its insolation rates to be among the lowest in Canada, as shown in Figure 11.

Figure 14: Photovoltaic (PV) Potential and Insolation



Source: Natural Resources Canada. "PV Potential and Insolation. www.nrcan-rncan.gc.ca. Downloaded August 5, 2011.

The U.S. Energy Information Administration estimates that the levelized cost of solar power installed in 2016 will range from $159 to $324 per MWh[10]. The cost of power from solar PV installations in Newfoundland is likely to be at or beyond the high end of this range due to Newfoundland's low insolation rates.

15. Nalcor appropriately excluded solar photovoltaic (PV) generation in both generation expansion alternatives because of Newfoundland's low insolation rates and the cost of power from solar PV installations.

[10] Ibid.

2.3.4 Wave and Tidal Power

Wave and tidal electricity generation has not been commercially applied in any meaningful quantities and does not appear likely to be commercially viable in the foreseeable future. As noted on the Wave Power in Canada[11] web site:

> *Although there are many companies that have overcome the challenges to harnessing ocean wave energy, there are still two main obstacles to overcome:*
>
> *Among the wide variety of wave energy systems, competing against each other, there is* [sic] *no clear technology leaders. The wave systems that are closer to a commercial stage cost about three times more than onshore wind systems.*
>
> *Clearly it will take time along with government and investor support to overcome these obstacles. At present nobody is willing to even estimate the time required to identify the technology leaders and to make them cost competitive.*

16. Nalcor appropriately excluded wave and tidal generation in both generation expansion alternatives because of its unproven commercial viability.

2.4 Fossil Fuel

Fuel Oil

NL Hydro currently uses No. 6 heavy fuel oil at its Holyrood thermal generation facility and No. 2 fuel oil at its other thermal facilities.

17. Nalcor appropriately included the continuation of oil-fired generation in both generation expansion alternatives because it is a proven resource in the Island's generation supply mix.

Natural Gas

Natural gas is available as an associated product from NL's off-shore oil production. In the Grand Banks off-shore of the Island, natural gas is generally re-injected into the reservoir to maintain or increase oil production. The closest commercial natural gas pipeline is in Nova Scotia.

According to a 2001 Gas Pipeline Study[12] by the Government of Newfoundland and Labrador, the sustainable economic natural gas extraction rate needed to support a submarine natural gas

[11] http://coppercanada.ca/electrical_wave_power/electrical_wave_powerS7.htm

transportation system off-shore of Newfoundland and Labrador would be approximately 700,000 Mcfd[13]. The Gas Pipeline Study also concluded that:

> "*Delivery of gas for domestic* [provincial] *use such as for power generation, industrial, commercial and residential is not economically feasible without integral development of delivery to Eastern Canada and the U.S.*[14]"

A 500 MW natural gas-fired Combined Cycle Combustion Turbine (CCCT) would require 84,000 Mcfd[15] of gas delivery capacity. Assuming 50 percent load factor for this plant, this would represent just over 5 percent of the 700,000 Mcfd rate. As such, it would not be possible for Nalcor's potential natural gas demand for electricity generation to warrant development of an off-shore natural gas resource and transportation system without securing significantly more commitments from other customers and regions to make up the remaining 95 percent of the commercial volumes required.

18. Nalcor appropriately excluded natural gas generation in both generation expansion alternatives because natural gas is not commercially available on the Island and there are, as yet, no firm development plans to bring natural gas to the Island.

Liquefied Natural Gas (LNG)

Another possible fossil fuel that could be utilized on the Island is liquefied natural gas (LNG). Navigant explored the feasibility of a LNG regasification facility that would serve (and be located in the vicinity of) a 500 MW natural gas-fired CCCT. The regasification facility would in turn receive liquefied natural gas from off-shore supply locations by ship.

As discussed in the previous section, the regasification facility would require capacity of approximately 84,000 Mcfd if sized to meet the peak demand of the CCCT. This would translate into a facility that was significantly smaller than 'standard' in the LNG business. Regasification terminals are typically built with sendout capacities of 500,000 Mcfd to 4.0 Bcfd[16]. Most LNG regasification terminals in North America have sendout capacities of 1 Bcfd or more.

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[12] *Technical Feasibility of Off-shore Natural Gas and Gas Liquid Development Based on a Submarine Pipeline Transportation System, Off-shore Newfoundland and Labrador, Final Summary Report* to the Government of Newfoundland and Labrador, Department of Mines & Energy, Petroleum Resource Development Division, submitted by Pan Maritime Kenny – IHS Energy Alliance, October 2001

[13] 1 Mcfd = 1,000 cubic feet per day ~ 1MMBtu per day

[14] Page 5.

[15] 500 MW x 7 MMBtu per MWh x 24 hours x 1 Mcf per MMBtu = 84,000 Mcf/day

[16] 1 Bcfd = 1,000,000,000 cubic feet per day ~ 1,000,000 MMBtu per day

For example, the Canaport LNG facility in Saint John, NB has a reported send-out capacity of 1.2 Bcfd[17].

Navigant estimates that the capital cost of an 84,000 Mcfd regasification and storage facilities would run in the range of $1 billion, plus the capital required for the new natural gas CCCT.

The commodity costs for LNG also need to be considered. The prices for long term, firm supply of LNG are normally linked to crude oil prices. As such, any long term utility contract that would be necessary for deliveries to the regasification facility in Newfoundland would see LNG prices linked to oil prices. In Navigant's opinion, the delivered prices to a LNG regasification facility sited on the Island under a long term contract are expected to be at a modest discount to the price of fuel oil Nalcor is already purchasing therefore offering no clear economic advantage for LNG as a fuel source.

Although the current tie between LNG prices and crude oil in the global LNG market is one that could change towards gas on gas pricing in the future, the market for long term, firm supply of LNG is currently, and for the foreseeable future is expected to be, referenced to oil.

19. Nalcor appropriately excluded liquefied natural gas (LNG) generation in both generation expansion alternatives because there is no clear economic advantage to using LNG given the required capital for LNG-related facilities, coupled with the linkage of long term LNG pricing to oil.

Coal

With respect to coal-fired generation, Navigant notes the proposed federal regulation that would limit the CO_2 emissions from a new coal-fired generating facility to that of a highly efficient combined cycle natural gas facility. This regulation is discussed is Section 3.3.8. Without some form of carbon capture and sequestration, a coal facility would not be able to meet this requirement.

20. Nalcor appropriately excluded coal-fired generation in both generation expansion alternatives because of its significant environmental risks.

2.5 Nuclear

Nuclear generation was not considered by Nalcor as a supply option alternative. A primary reason for this omission is the fact that Newfoundland Electrical Power Control Act of 1994 establishes a policy which rejects consideration of nuclear power in power supply planning.

[17] According to the Canaport homepage at: http://www.canaportlng.com/

Recent estimates of overnight nuclear generation capital costs set the cost range from $5,339[18] to $10,000/kW[19]. Using this range, a new 1,000 MW nuclear generation facility would cost between $5.4 and $10 billion.

It is also worth noting that nuclear generation cannot readily start up and stop or ramp up and down like fossil fuel-fired plants and storage hydroelectric facilities and must generally operate at a steady output 24-7 as baseload generation. The typical size for new nuclear facilities is in the 1,000 MW per unit range, significantly more than the minimum demand on the Island. Such a facility could not operate as a baseloaded plant in the Island's electricity system.

There are additional barriers to nuclear generation. Due to the recent and ongoing events in Japan, the regulatory framework which governs new nuclear plant licensing has been shaken and has taken an increasingly conservative path with regards to the approval of new nuclear facility applications. Public perception of nuclear generation has also been greatly damaged, which would create substantial project risk even after the facility completes the permitting process. All these challenges coalesce to increase the timing risks (and associated costs) of new nuclear generation.

21. Nalcor appropriately excluded nuclear generation in both generation expansion alternatives because of provincial legislation, project capital costs and risk factors.

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[18] Source: Updated Capital Costs for Electricity Generation Plants – November 2010. US Energy Information Agency, Department of Energy. Available at http://www.eia.gov/oiaf/beck_plantcosts/pdf/updatedplantcosts.pdf

[19] Source: The Brattle Group – "Prospects for a Nuclear Revival in the United States." February 2011. Available at http://www.brattle.com/_documents/UploadLibrary/Upload921.pdf

3 Assumptions for Island Demand and Supply Options

This section reviews the reasonableness of the assumptions and inputs Nalcor used with respect to the supply options it considered. These assumptions are grouped into:

- Demand projections
- Conservation and Demand Management Projections
- Supply options characteristics
- Anticipated legislative mandates

3.1 Demand Projections

Nalcor used an econometric analysis that consists of multivariate regression equations that model various domestic and commercial electricity requirements as a function of population, income or gross domestic product (GDP), prices, housing and commercial stock, weather, and efficiency gains. The projections for the key economic variables used in Nalcor's econometric analysis are provided by the Department of Finance, Government of Newfoundland and Labrador.

The prevalence of electric heat as a primary driver of electricity demand and energy is expected to continue in view of recent and forward looking energy prices which impact equipment and fuel choice decisions for space heating[20]. The market share for electric heat is projected to increase from 59 percent in 2010 to 66 percent in 2029[21].

Other key assumptions to the forecast:

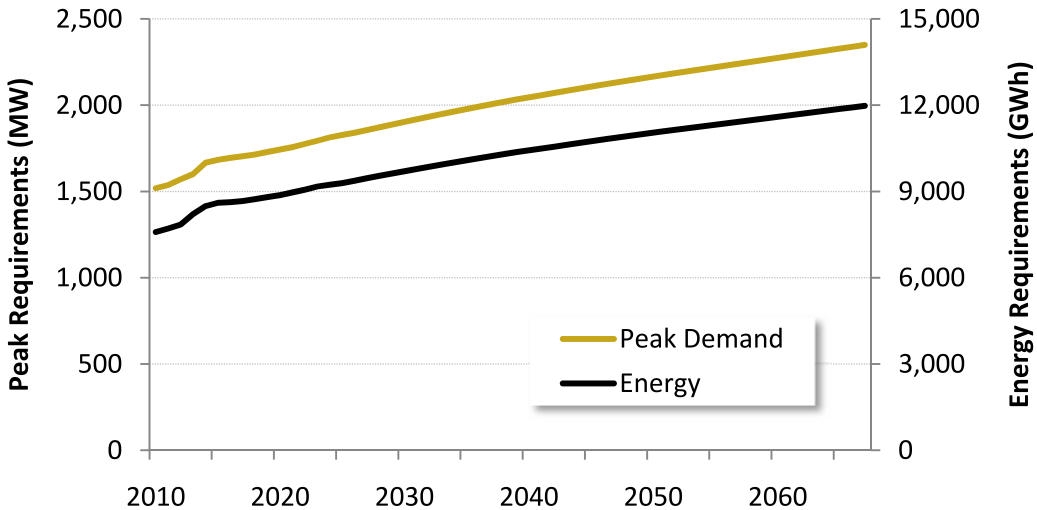
- Island newsprint mill and oil refinery operations are maintained
- Teck mine expected to operate through 2013
- The Vale nickel processing facility is scheduled to be provided a transmission connection in late 2011 with full production expected in the 2015 time frame, and
- Economic growth resulting from the development of the Hebron oil field.

Figure 15 presents the forecast peak demand and energy requirements for the Island.

[20] "Nalcor Response to Panel Information Request March 21, 2011." April 1, 2011.

[21] "Synopsis of 2010 Generation Expansion Decision" Exhibit 1 Addendum, July 2011.

Figure 15: Newfoundland Peak Demand and Energy Requirements



Source: Nalcor. "Synopsis of 2010 Generation Expansion Decision" Exhibit 13b. July 2011

Nalcor's forecast load growth in the 2010 – 2067 period is 0.8 percent[22]. Exclusive of the impact of Vale's facility, the forecast load growth in the 2010 – 2067 period is 0.7 percent. For comparison, the National Energy Board projects a 1 percent compound annual growth rate in electric energy demand for Canada as a whole from 2010 to 2020[23].

Given the forecast growth in demand, additional capacity will be required to serve Island demand in 2015.[24] Similarly, Nalcor is forecasting a requirement for additional energy in the 2020 timeframe to meet the Island's energy needs.

22. Nalcor's forecast methodology is consistent with generally accepted utility practice and the base forecast for demand and energy growth is reasonable.

23. Absent new supply, the Island will experience a capacity deficit in 2015 and an energy deficit in the 2020 timeframe

3.2 Conservation and Demand Management Projections

NL Hydro and Newfoundland Power commissioned a study of conservation and demand management in 2008.[25] Marbek, a reputable consultancy based in Ontario, conducted the

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[22] Presentation to Municipalities of Newfoundland and Labrador, May 5, 2011

[23] Appendix 2, Table A2.1, *2009 Reference Case Scenario: Canadian energy demand and supply to 2020*, National Energy Board, July 2009

[24] Exhibit 16, Generation Planning Issues 2010 July Update

analysis. The study considered the technical, economic, and achievable potential for CDM in the residential, commercial, and industrial sectors from 2006 to 2026.

Marbek's achievable potential forecast represents the CDM savings that it may be possible to achieve within the study period based on expected customer participation levels. Achievable potential recognizes that it is difficult to induce customers to purchase and install all the electrical efficiency technologies that meet the criteria defined by the economic potential forecast. Marbek provided two estimates of achievable potential: a Lower Achievable Potential and an Upper Achievable Potential. The Lower and Upper Achievable Potential estimates for the Residential, Commercial and Industrial sectors are provided in Table 2.

Table 2: Achievable CDM Potential Estimates (Marbek)

	Annual GWh				Annual GWh Savings (2026)		Percent savings (on base year consumption)	
Sector	Base year (2006)	Forecast without CDM (2026)	Upper Ach.	Lower Ach.	Upper Ach.	Lower Ach.	Upper Ach.	Lower Ach.
Residential	3,228	3,968	3,529	3,732	439	236	14%	7%
Commercial	1,881	2,233	1,846	1,972	387	261	21%	14%
Industrial	1,359	1,484	1,360	1,425	124	59	9%	4%
Total	**6,486**	**7,685**	**6,735**	**7,129**	**950**	**556**	**15%**	**9%**

Many jurisdictions with mature CDM programs generally target cutting load growth in half through CDM – which would be similar to the Lower Achievable Potential as shown in Table 2. Based on this comparison with other jurisdictions with mature and extensive CDM programs, such as British Columbia[26], Navigant believes that the Upper Achievable Potential would be very aggressive given the early stages of the CDM efforts of NL Hydro and its partner, Newfoundland Power.

The aggressiveness of the Upper Achievable Potential is reinforced by the following statement from the Marbek report:

> *For the purposes of this study, the Upper Achievable Potential can, informally, be described as: "Economic Potential less those customers who "can't" or "won't" participate*[27]

---

[25] Conservation and Demand Management (CDM) Potential Newfoundland and Labrador: Residential, Commercial and Industrial Sectors. Prepared by: Marbek Resource Consultants Ltd. January 31, 2008.

[26] BC's Energy Plan includes the following energy conservation and efficiency policy: "*Set an ambitious conservation target, to acquire 50 per cent of BC Hydro's incremental resource needs through conservation by 2020.*"

[27] Page 104, *Conservation and Demand Management Potential Newfoundland and Labrador, Residential Sector Final Report*, Marbek Consultants Ltd., January 18, 2008

Essentially, based on this definition, the Upper Achievable Potential could only be realized with programs in which all customers – except those who can't or won't – participate. Based on Navigant's experience in CDM program design and evaluation, this level of participation could not be realized across an entire portfolio of programs over a twenty year period. As such, it would not be reasonable to utilize the Upper Achievable Potential for system planning purposes.

Navigant believes a more realistic, yet still very aggressive, level of CDM savings to consider for system planning purposes would fall halfway between the Upper and Lower Achievable Potential as estimated by Marbek. This would yield annual savings of 750 GWh at the end of a 20 year period of very aggressive CDM programs, regulations and codes and standards. This level of savings – which could be considered an upper planning estimate – would have CDM eliminating approximately half of forecast growth in electricity consumption on the Island – consistent with many other jurisdictions that target CDM to eliminate half of the growth in electricity consumption. Realizing this level of savings would require investing approximately $400 million in energy efficiency over 20 years, plus:

- Strong and supportive government policy through legislation, regulation, codes and standards
- Strong support of and co-operation from Newfoundland Power
- Municipal support and co-operation
- Development of a strong conservation culture among Newfoundlanders and Labradorians, and
- Programs specifically targeting the unique needs and attitudes of Newfoundlanders and Labradorians.

Note that the program funding would be subject to regulatory approval and would typically be recovered from ratepayers.

As an alternative to this very aggressive level of CDM savings, Navigant believes CDM savings of 375 GWh savings by the end of 2031 could be taken as a lower planning estimate. The Marbek Lower Achievable Potential estimate falls exactly in the middle of these two planning estimates.

Nalcor and Navigant modeled a sensitivity case to test the effect of achieving these levels of CDM savings on the CPW for the Isolated Island alternative. The results of this analysis are provided in Section 5.

Current Utility CDM Programs

NL Hydro and Newfoundland Power jointly filed a *5 Year Energy Conservation Plan: 2008 – 2013* with the PUB in June 2008, outlining a target of 79 GWh/year savings by the Plan's final year in

2013. This plan will be updated in 2011 as a joint utility effort and will explore an expansion of programs and increased savings targets. To date, the utilities have seen lower than predicted initial savings, but with positive signs of growth. The Energy Conservation Plan reflects the key roles of each utility – NL Hydro as the primary generator of electricity for the province and Newfoundland Power as having the majority of the customer base. The resulting CDM programs are then administered by the utilities to their direct customers, meaning Newfoundland Power is the administrator of the majority of the commercial and residential programming and NL Hydro for the industrial sector. Jurisdiction for these programs rests with the PUB, and NL Hydro and Newfoundland Power file annual activity reports with the PUB.

takeCHARGE is the joint utility energy efficiency brand program administered by NL Hydro and Newfoundland Power. takeCHARGE offers residential rebate programs for insulation, thermostats and ENERGY STAR windows as well as a commercial lighting program and an industrial energy efficiency program.

NL Hydro and Newfoundland Power expect to achieve 10.4 GWh and 2.1 MW of savings in 2011, as shown in Table 4-1.

Table 3: CDM Savings 2009-2011

	2009	2010	2011 (Forecast)
Energy (GWh/yr)	2.7	5.2	10.4
Demand (MW)	0.9	1.7	2.1

Source: Nalcor Response to Panel Information Request March 21, 2011. April 1, 2011.

These CDM savings arising from utility sponsored programs are not yet explicitly reflected in the load forecast.

24. Nalcor could consider the impact of a longer term CDM initiative.

3.3 Supply Option Characteristics

3.3.1 Cost Estimates for Lower Churchill Projects

While the two alternatives evaluated for meeting the Island supply entail numerous capital additions over the analysis period, the major projects from a near-term capital cost perspective are the Muskrat Falls Generation Facility and the Labrador – Island Transmission Link which are planned for commercial service in 2016/17. These facilities are projected to cost $2,869 million and $2,060 million, respectively, in nominal dollars including contingencies and escalation allowances.

Base Estimate

The Base Estimate was developed using four key inputs: (i) scope, (ii) construction methodology and schedule, (iii) price factors, and (iv) performance factors. With respect to estimating capital costs, the projects were divided into the major construction components (e.g., powerhouse, dams, turbines, submarine cables, transmission towers, converter stations) for which the costs of materials, labour and equipment were estimated. Indirect costs and support facilities were added to the estimates. The following table shows a breakdown of the final DG2 Base Estimate.

Table 4: DG2 Base Cost Estimate

Component	DG 2 Base Estimate (Direct 2010$ millions CAD)
Muskrat Falls	
Site Preparation, Access, Accommodations Complex, Site Services and Catering and Reservoir Clearing	$373
Intake, Powerhouse, Turbines and Generators	$923
Spillway Structure, RCC Dams (North & South), Cofferdams, and North Spur Stabilization	$274
Switchyards and MF to CF Transmission Lines	$261
Feasibility Studies, EA, Insurance, Engineering & Design, Project Management	$375
Muskrat Falls Total	**$2,206**
Labrador-Island Transmission Link	
Converter Stations, Electrodes and Switchyards	$466
SOBI Cable Crossing, Land Sites and Transition Compounds	$324
HVdc Overland Transmission	$400
Island System Upgrades	$194
Feasibility Studies, EA, Insurance, Engineering & Design, Project Management	$232
Labrador-Island Transmission Link Total	**$1,616**
Grand Total	**$3,822**

LCP Risk Assessment and Contingencies

Nalcor undertook a detailed risk analysis of the two LCP projects. The analysis entailed the development of a Tactical Risk Assessment a Time Risk Assessment, and a Strategic Risk Assessment. This analysis also informed Nalcor's estimate of project contingencies.

The probabilistic Tactical Risk Assessment considered the impact of such factors as schedule, performance factors and price risks on the Base Estimate. High and low ranges were developed for each major cost item predicated on the uncertainties associated with each of the four key inputs.

The primary project Timing Risk factors are: the Generation Project release from EA; Powerhouse Excavation and Primary Powerhouse Concreting; and the awarding of the Engineering, Procurement and Construction Management (EPCM) contract. Nalcor has placed significant effort in its Time Risk Assessment on developing and implementing a de-risking strategy for the delivery schedule. Mitigation activities have included preparing to issue a Bulk Excavation Contract Package to facilitate an early commencement of Powerhouse Excavation, and late 2010 award of three separate contracts for Turbine Model Testing to de-risk the overall turbine component delivery schedule, which is critical to maintain the planned Powerhouse concrete schedule.

Developing a cost and schedule for long-term construction projects such as Muskrat Falls Generation and the Labrador-Island Link is an extremely complicated process. The process becomes substantially more complex when the project involves two completely separate and different facilities that need to commence commercial service at the same time. If one of the two projects is completed on schedule, while the other is delayed, it is doubtful that cost recovery for the completed project could begin since neither project would likely be considered "used and useful" without the other. Nalcor has taken steps to mitigate this risk by (i) incorporating uncertainties associated with major excavations and structures in the contingency allowance; (ii) scheduling installation of the undersea HVdc cable one year before it would be required; and (iii) engaging the same EPCM Consultant for Muskrat Falls and the Labrador-Island Link. In addition, the overall plan entails a 345 KV transmission interconnection between Muskrat Falls and Churchill Falls which would accommodate more flexible water storage arrangements, i.e., the Muskrat Falls project could potentially be used and useful even if completion of the Labrador-Island Link is delayed. Nalcor will continue to assess, and if necessary mitigate, potential project-on-project risks as part of its overall project planning leading to the DG3 decision.

While the Strategic Risk Assessment primarily focuses on financial exposure, time exposures for strategic risks are considered in the Time Risk Assessment discussed above. Strategic risks were apportioned among organizational risks, financial risks, interface risks, commercial risks, health, safety and environmental risks, engineering/technical risks, environmental approvals and permitting risks, stakeholder risks, construction risks, turbine supplier risks, deescalation/inflation risks, transmission risks, environmental assessment risks, enterprise risks and technology risks. For each of the strategic risks, the assessment includes recommendations for mitigating the related risk. For example, with respect to the risks associated with the limited number of HVdc specialty suppliers and installers, the recommendations include: (i) optimizing packaging strategy of HVdc specialties equipment and services to entice key players; and (ii) select and engage early to ensure availability. Since the assessment has been completed, Nalcor has already taken actions to mitigate certain identified risks, e.g., reverting back to traditional LCC HVdc technology to alleviate the risk of failure of application of VSC HVdc technology for the Island Link.

The foregoing risk assessments were used by Nalcor to determine that a contingency of 15 percent of the Base Estimate was considered appropriate and has been incorporated in the capital estimates.

LCP Escalation

While inflation is typically treated in a simplistic manner, e.g., an overall rate applied across the project, Nalcor recognized that because of changes in the economic climate, a more sophisticated approach to developing the Escalation Component was warranted. Based on the identified best practices, a methodology for estimating cost escalation linking estimated capital costs with project scheduling was developed. This methodology provides escalation estimates on commodity, project component and aggregate levels that ultimately produced escalation index categories for each line item. Indices provided from forecasting services were applied to the escalation index categories resulting in cumulative escalation factors for the two LCP projects as shown in the table below.

Table 5: Escalation Factors (Percent)

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 Trans. Link	1.00	1.02	1.04	1.08	1.12	1.16	1.20	1.24	1.29	$208 million

Capital Cost Estimate

Combining the three components described above, with one minor adjustment for pre-2010 historical costs, results in the escalated capital costs shown in the following table.

Table 6: Summary of Muskrat Falls and Labrador-Island Link Capital Cost Estimate

All values in $ millions Canadian

Project	Base Estimate (2010$)	Historical Cost (pre 2010)	Adjusted Base Cost (Base Cost – Historical)	Estimate Contingency	Escalation Allowance	Total Project Cost (Escalated Nominal)
Muskrat Falls Generating Facility	$2,206	$20	$2,186	$328	$335	**$2,869**
Labrador – Island Transmission Link	$1,616	$42	$1,574	$236	$208	**$2,060**

25. Nalcor's risk assessment analysis for Muskrat Falls and the Labrador-Island Link project was thorough and comprehensive.

26. Nalcor's focus on time, tactical and strategic risks for the Muskrat Falls and Labrador-Island Link is consistent with best practices and provides a high level of confidence in the integrity of capital cost estimates.

3.3.2 Cost Estimates for other Nalcor Capital Projects

In addition to the two major projects described above for the Interconnected Island alternative, Navigant reviewed the capital cost projections for the smaller generating projects that would be added over the analysis period for both alternatives, and the estimated costs for the Holyrood environmental improvements and life extension upgrades under the Isolated Island alternative.

It is noteworthy that because the generation expansion analysis period (through 2067) is longer than the expected service life of thermal and wind generators, the plan reflects a generation replacement cycle in the Isolated Island alternative. The replacement cycle is less significant in the Interconnected Island alternative because of the large capacity and long service lives of Muskrat Falls and the Labrador-Island Link.

Table 7 sets forth the projected capital costs (on a $ per kW basis) for the proposed generation additions. Nalcor has significant past experience with projects very similar to most of the other Nalcor capital projects. Projecting installed generation costs on a per kilowatt basis and by generation technology (e.g., hydroelectric, wind, thermal) is a standard utility industry practice.

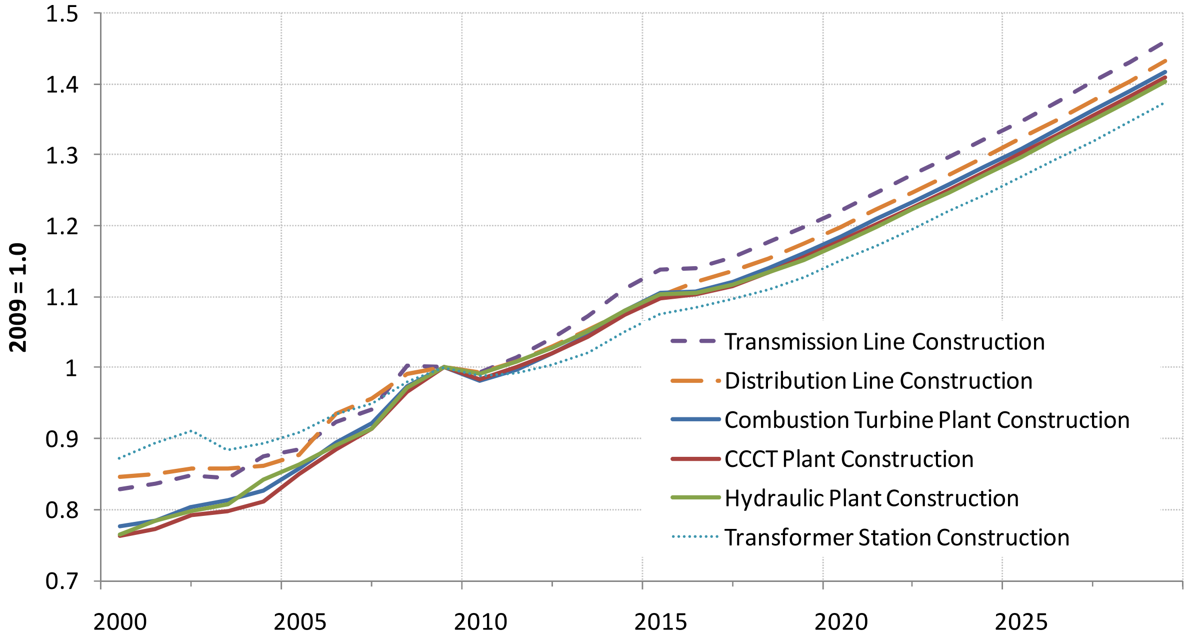
Table 7: Unit Capital Costs for Projected Supply Additions

Projected Capital Costs ($2010)	Capital Cost - $/kW
Hydroelectric Projects	
Island Pond Development - 36 MW	$4,617
Round Pond Development - 20 MW	$7,110
Portland Creek - 23 MW	$3,909
Wind Projects	
Replace Fermeuse Wind - 27 MW	$2,323
Replace St. Lawrence Wind - 27 MW	$2,323
Thermal Projects	
Holyrood/Greenfield Unit 2 CCCT - 170 MW	$1,213
Greenfield CCCT Unit 1 - 170 MW	$1,611
Greenfield CT - 50 MW	$1,303

Navigant has reviewed these capital costs and determined that such costs are reasonable based on its experience with similar projects using the three distinct generating technologies. It must be emphasized that when comparing costs across generation technologies, there are many unique factors that impact the overall economics of each, e.g., the expected service life of a hydroelectric project may be three times that of a thermal plant, and wind and hydroelectric projects have no fuel costs. Also, with respect to the hydroelectric projects, there is no "average" cost, since each hydroelectric project has its own unique engineering and economics.

In order to escalate these costs to the construction period, Nalcor developed weighted cost indices for capital assets and used projections on various producer price indices from Global Insight to drive each weighted index. Figure 16 presents the escalation for construction costs for Nalcor's other capital projects.

Figure 16: Nalcor Construction Escalation Indices at January 2010



In addition to the foregoing cost estimates, with respect to the Isolated Island alternative, Navigant also reviewed the projected costs for the Holyrood life extension upgrades and pollution control investments (electrostatic precipitators, scrubbers, low NOx burners) that total over $800 million (nominal in-service dollars) as per Nalcor documents. The pollution control equipment represents about 70 percent of the total cost. Most of the pollution control equipment and life extension upgrades would be installed in the 2015 to 2019 time frame and would be retired with the Holyrood facility in 2036. Navigant understands that if the Holyrood plant is to remain in service, the pollution control investments are required to conform to the Province's energy policy as discussed in the Environmental Restrictions section. These investments would typically result in a reduction of the plant's efficiency primarily because of increased station service requirements, which has been factored into the CPW analysis.

In light of the relatively short service life for the capital intensive Holyrood pollution control investments and life extension upgrades, replacing Holyrood with new combined cycle units in 2017 as an alternative warranted consideration. Nalcor modeled the effect of early replacement of Holyrood with CCCTs as a variant of the Isolated Island alternative. The results of this analysis are provided in Section 5.

27. Nalcor's estimated capital costs and escalation methodology for the various supply options considered in the two generation expansion alternatives was reasonable.

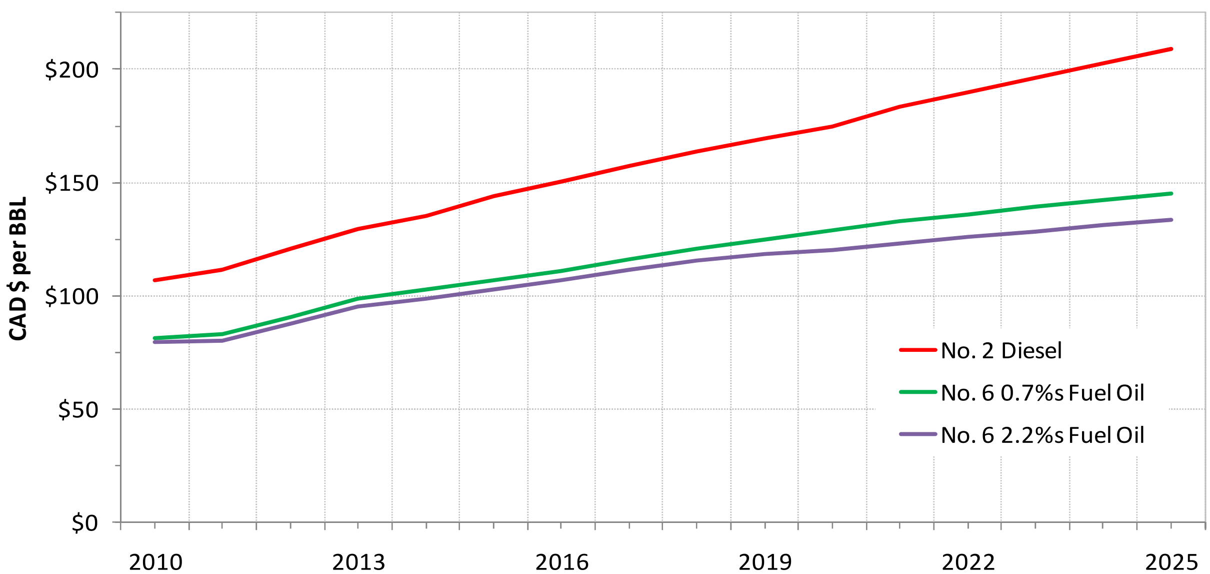
3.3.3 Fuel Cost Forecasts

PIRA Energy Group of New York, a leading international supplier for energy market analysis and forecasts, and oil market intelligence in particular, supplies the fuel oil price projections used by Nalcor through 2025. Changes in oil prices beyond 2025 through the end of the analysis period in 2067 only include provision for general inflation.

These forecasts are used in production costing for the existing Holyrood and combustion turbine (CT) thermal plants, plus for any new combined cycle and simple cycle combustion turbines. Whereas the primary risks for the Interconnected Island alternative are largely capital-cost related, the Isolated Island's primary risk is associated with fuel costs. This risk is further explored through sensitivity cases in Section 6.

Annual fuel cost projections used by Nalcor in its generation expansion analysis are set forth in Figure 17.

Figure 17: Fuel Cost Forecast



Source: PIRA Energy Group and Nalcor Energy at January 2010

Navigant compared those results with the fuel cost projections issued by the United States Federal Energy Information Administration (EIA). The annual price change projections in the EIA's Annual Energy Outlook 2011[28] were slightly higher than those used in the analysis, but were close enough for the projections used by Nalcor to be considered reasonable. The prices in both forecasts are similar in the earlier years of the review period, but the EIA prices escalate at a higher rate in the later years.

[28] EIA Annual Energy Outlook 2011 - Published April 2011, available at http://www.eia.gov/forecasts/aeo/ The oil prices specifically come from the Interactive Table Viewer accessible from this site.

> **28. The fuel cost forecast used by Nalcor in its analysis of the generation expansion alternatives was reasonable.**

3.3.4 Heat Rates

The following table sets forth the range of heat rates employed in the analysis for the existing and proposed generating units.

Table 8: Heat Rates Used in Nalcor Supply Decision

Heat Rates	Fuel Oil	Max MMBtu per MWh	Min MMBtu per MWh
Existing			
Holyrood - Units 1,2, & 3	#6	9.78	10.39
CTs	#2	12.26	12.26
Diesels	#2	10.97	10.97
Future			
CT - 50 MW	#2	9.43	9.43
CCCT - 170 MW	#2	7.64	8.63

As a possible alternative to a 3x170 MW CCCT facility, Navigant discussed with Nalcor the possibility of using a larger and more efficient Frame facility that would be expected to have a heat rate of less than 7.00 MMBtu per MWh. Nalcor advised that it elected the three 170 MW units because the largest single contingency that its system can accommodate in the Isolated Island alternative without potentially becoming unstable is 175 MW. Accordingly, Nalcor's choice of the 170 MW combined cycle units is appropriate under the circumstances because of potential system stability concerns with larger units.

3.3.5 O&M

Table 9 below sets forth the projected fixed and variable Operating and Maintenance costs in 2010$ (except where noted) that were used by Nalcor in its generation expansion analysis. While the fixed O&M costs pertaining to the existing Holyrood plant may seem high, these levels are consistent with industry experience as steam plants require relatively high staffing levels compared to combined cycle/combustion turbine facilities.

Table 9: Projected Operating and Maintenance Costs[29]

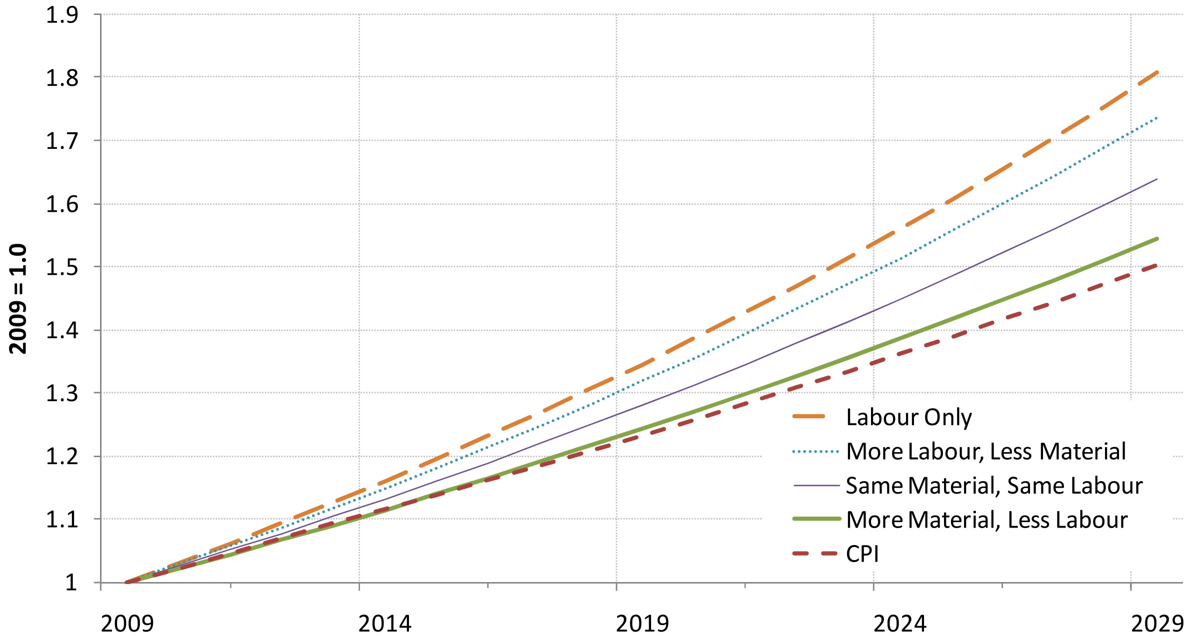
Facility	Fixed Annual Cost ($ per kW - 2010$)	Variable O&M ($ per MWh 2010$)
Island Pond	15.79	N/A
Portland Creek	17.97	N/A
Round Pond	20.66	N/A
Wind (new)	28.89	$5.90
Holyrood CCCT	9.22	$5.32
Greenfield CCCT – Unit 1	10.49	$5.32
Greenfield CCCT – Unit 2	9.22	$5.32
Holyrood (existing steam units)	41.39	$1.28
Holyrood (ESP and FGD)	$11M (2015) to $24M (2033) nominal	
Muskrat Falls	$13M (2018) to $44M (2066) nominal	
LIL	$14M (2017) to $50M (2067) nominal	
CTs (SVL and HWD)	9.11	N/A
CTs (Greenfield)	10.49	$5.32

N/A = Not Applicable

For escalation of O&M expenses, Nalcor used, as applicable, specific rates for different mixes of labour and material. With respect to general inflation post 2010, Nalcor uses a forecast as provided by the Conference Board of Canada. Figure 18 presents the O&M escalation indices used by Nalcor.

[29] Fuel costs not included.

Figure 18: Nalcor General Inflation and O&M Escalation Indices at January 2010



3.3.6 Projected Retirements

The following two tables set forth the retirement years that the Nalcor analysis assumed for existing generating units for the two generation expansion alternatives and the anticipated service lives assumed by Nalcor for the different categories of facilities.

Table 10: Retirements - Existing Units[30]

	Isolated Island Alternative	Interconnected Island Alternative
Holyrood Units 1 & 2	2033	2021
Holyrood 3	2036	2021
Hardwoods CT	2022	2022
Stephenville CT	2024	2024

For the Isolated Island alternative, the Holyrood retirement age would be in excess of 60 years which is longer than the typical average service life for similar units. However, because of the historical lightly loaded service experienced by those units, a service life longer than the average for such facilities would be expected.

[30] Existing hydro plants, both Hydro-owned and owned by others, are assumed to never retire. Existing Hydro diesel units and thermal units owned by others, primarily used in a stand-by mode, are assumed to never retire.

Table 11: Operating Life - Future Units

	Years
Wind Farms	20
CTs	25
CCCTs	30
Hydroelectric	Beyond Study Period
HVdc Link	50

The projected operating lives for the different categories of new facilities are consistent with general industry standards.

3.3.7 Outages

Scheduled

According to information provided by Nalcor, it is assumed that the three Holyrood units undergo scheduled maintenance eight weeks per year. Nalcor assumes that scheduled maintenance for the other thermal units would be two weeks per year. With respect to the hydroelectric and wind units and the Labrador-Island Link, it was assumed that scheduled maintenance would be performed in the off-peak months. Nalcor's schedule for maintenance outages conforms with standard utility practices pertaining to generation and transmission maintenance. Virtually all utilities schedule major generation maintenance during off-peak periods.

Forced Outage Rates

A forced outage is an unplanned outage that requires all or a portion of a project to be removed from service. The following table sets forth the forced outage rates employed by Nalcor in its analysis of the generation expansion alternatives.

Table 12: Forced Outage Rates

Category	Forced Outage Rate (Percent)
Existing Hydroelectric	0.90
Future Hydroelectric	0.90
Gas Turbine	10.62
Holyrood	9.64
Diesel	1.18
Combined Cycle	5.00
LIL	0.89
Hydroelectric Purchases	2.26
Customer-owned Generation	3.19

The forced outage rates for the existing facilities are predicated on actual experience and, as such, are appropriate to use for the analysis. The forced outage rates employed by Nalcor for the future units appear to be reasonable with one exception. Based on Navigant's experience, it would be expected that the forced outage rate applicable to the new 50 MW combustion turbines, such as a GE LM6000, would be more in line with the 5.00 percent rate applicable to the new combined cycle plants rather than the 10.62 percent shown above. Nalcor acknowledges that the 5.00 percent forced outage rate may be more appropriate for simple cycle combustion turbines and will consider using this rate in future analyses.

29. The heat rates, operating and maintenance costs, operating lives, projected retirements, and outage rates used by Nalcor in its analysis of the generation expansion alternatives were reasonable.

3.3.8 Environmental Restrictions

Based on Holyrood's current Certificate of Approval, the Holyrood station is required to burn 0.7 percent sulphur fuel. This is necessary because the boilers at Holyrood do not have environmental equipment for controlling sulphur dioxide (SO_2) or particulate emissions.

In addition to the current restrictions, NL's 2007 Energy Plan requires that in the event that the Lower Churchill Project does not proceed, scrubbers and precipitators must be installed at Holyrood. To comply with the Energy Plan, Nalcor would install electrostatic precipitators that would be expected to remove 95 percent of particulates from flue gas emissions and a flue gas desulphurization system that would remove 95 percent of sulphur dioxide (SO_2) emissions.

While the installation of precipitators and a flue gas desulphurization system would be expected to remove virtually all of particulates and SO_2 as described above, that equipment will actually result in a slight increase in the amount of Carbon Dioxide (CO_2) emitted from Holyrood.

One potential concern associated with incurring more than $600 million of pollution control upgrades (along with more than $200 million of life extension improvements) for Holyrood is the possibility that the federal government may impose restrictions on CO_2 emissions for existing oil-fired power plants in the future. A federal regulation was recently proposed that would establish a regime for the reduction of CO_2 emissions that result from the production of electricity by using coal as a fuel[31]. Specifically, the regulation would limit the intensity of CO_2 emissions to 375 tonnes per GWH of electricity produced from fossil fuel during the calendar year. This is an extremely low CO_2 emissions target that, for the most part, could only be met by a very efficient combined cycle generator fuelled by natural gas.

Following are the estimated CO_2 intensity levels for the existing and future Nalcor units as well as a new gas fired combined cycle facility.

Table 13: GHG Intensity by Generation Type

Generating Facility	CO_2 Intensity (Tonnes per GWh)
Holyrood (No. 6)	734
Existing CTs (No. 2)	907
New CCCTs (No. 2)	565
New CTs (No. 2)	697
New Gas CCCT (Gas)	340

As indicated above, even the relatively efficient new CCCT fueled by No. 2 oil would have a GHG emission intensity well in excess of the 375 tonnes per GWh limit. Clearly, in the event that legislation similar to that described above were to apply to all fossil-fired generating stations, the Isolated Island option would be at risk since oil fired CCCTs, even the most efficient models fuelled by kerosene which has a lower CO_2 intensity, could not meet the threshold requirement. It should be noted that unlike previous legislation in which a facility that could not meet the requirements could buy credits from others, such is not the case with respect to the recently proposed federal legislation. That legislation requires that a facility that cannot meet the requirements is at risk of being permanently shut down. While the foregoing

[31] Reduction of Carbon Dioxide Emissions from Coal-Fired Generation of Electricity Regulations. The consultation version of the proposed regulation is available at:
http://www.ec.gc.ca/Content/2/E/5/2E5D45F6-E0A4-45C4-A49D-A3514E740296/E_Consultation.pdf

legislation is directed at coal plants, there have been indications that similar legislation may be proposed for oil fired generation.

Navigant also believes that other forms of greenhouse gas (GHG) emission mitigation legislation are possible over the supply decision horizon. Nalcor and Navigant modeled a sensitivity case to test the effect of the introduction of carbon pricing on the CPW for the Isolated Island case. The results of this analysis are provided in Section 5.

30. **Nalcor could consider how future environmental legislation, such as limits on the unit emission rates for fossil-fuel fired generation that could force the closure of Holyrood or the introduction of carbon pricing that would increase thermal production costs, would affect its supply alternatives.**

3.3.9 Power Purchases from Muskrat Falls

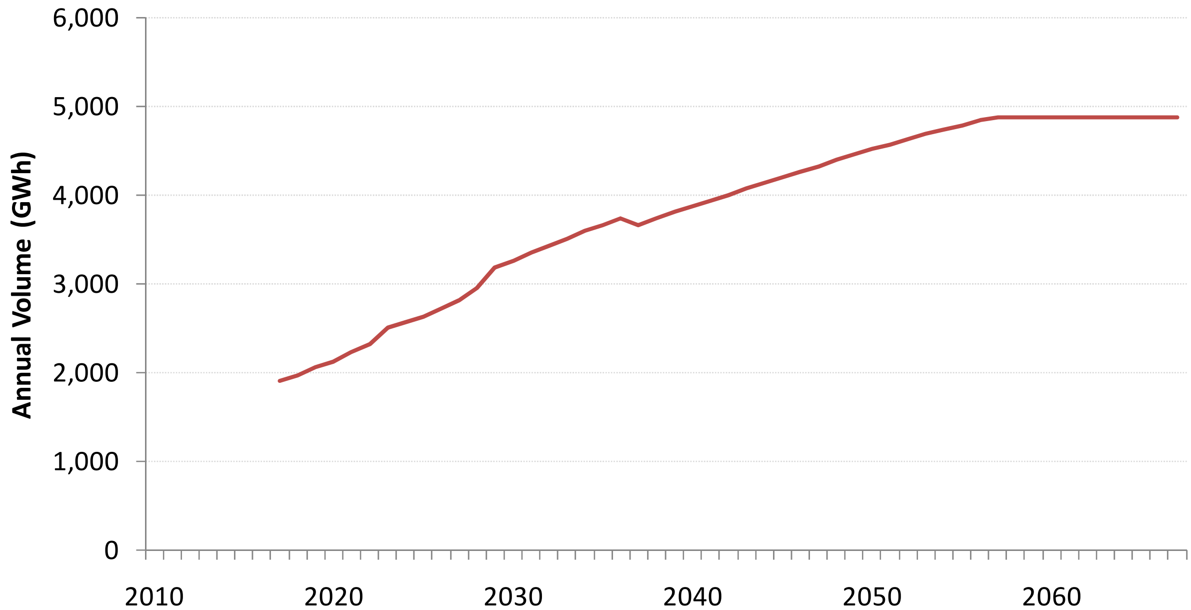
Just as the power from Muskrat Falls is a critical supply component in the Interconnected Island alternative, the cost of power purchases for Muskrat Falls is a critical driver of the economics of the Interconnected Island alternative.

In advance of DG2, Nalcor considered frameworks for proposing a supply price for the Island block. The context at the time was that exports revenues (from Muskrat Falls production over and above the Island block) were possible but not assured.

Nalcor determined through analysis that the Muskrat Falls project would be financially viable if Muskrat Falls recovered its full costs on the Island block, priced on an escalating per MWh supply price basis, returning an 8.4 percent cost of capital over a 50-year supply agreement. The $76 per MWh supply price (expressed in 2010$, escalating at 2 percent and applied to projected island market volume) is the supply price that returns the target 8.4 percent cost of capital to Muskrat Falls' shareholder assuming no other sales are made. The supply price derived, combined with revenues projected from monetization of excess energy sales, would provide a return for Muskrat Falls commensurate with a long term projected return (9 percent – 10 percent) for a regulated utility investor.

The forecast Island requirements for Muskrat Falls energy through 2067 are provided in Figure 19.

Figure 19: Muskrat Fall Projected Purchase Volumes



Navigant believes this is a reasonable approach for setting the Muskrat Falls power purchase price because the unit price remains constant in real dollar terms over the term which provides electricity ratepayers on the Island with a significant degree of rate certainty for this component of their supply. Navigant also believes that the 8.4 percent return to capital Nalcor expects given the power purchase price and NL Hydro volume requirements is reasonable.

31. The Muskrat Falls pricing approach used by Nalcor was appropriate and sufficiently well defined for the purposes of 1) estimating the Muskrat Falls power purchase price, and 2) informing the DG2 decision.

Navigant understands that Nalcor will be undertaking further work leading up the DG3 decision to further define the factors affecting the power purchase price and the degree of volumetric flexibility to ensure the proper treatment of any new information or sensitivity analysis affecting the price in the DG3 decision.

4 Process to Evaluate the Supply Options

4.1 Strategist

As discussed previously in section 1, the outcome of the generation planning analysis is a metric called Cumulative Present Worth (CPW), which is the present value of all incremental utility capital and operating costs incurred by the utility to reliably meet a specific load forecast given a prescribed set of reliability criteria. Where one alternative cost future for the grid has a lower CPW than another alternative supply future, the option with the lower CPW will be preferred by the utility, consistent with the provision of mandated least cost electricity services. From a financial planning perspective, the supply future with the lowest CPW will translate into the lowest overall revenue requirements. The discount rate used in Strategist to calculate CPW is 8 percent, consistent with the NL Hydro's regulated average long-run weighted cost of capital.

Nalcor uses Ventyx's Strategist software to evaluate the supply options. Strategist is an integrated strategic planning computer program that allows modeling of the current and future electric power system and that performs, among other functions, generation system reliability analysis, production costing simulation and generation expansion planning analysis. Given the current generation system, available resource options, a load forecast and other inputs, as will be described, algorithms within Strategist evaluate all of the various combinations of resources and produce 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.

The Ventyx Strategist modules used to derive the CPW were:

1. Load Forecast Adjustment (LFA)
2. Generation and Fuel (GAF)
3. Capital Expenditure and Recovery (CER)
4. PROVIEW (PRV)

4.2 Modeling Inputs in Strategist

Nalcor incorporated the inputs described in Section 4 into the analysis and ran the model over the 2010 to 2067 period. The analysis involved considering the CPW of different combinations of resources. The factors reflected in the CPW calculation included:

- capital cost of new facilities
- fuel cost
- line losses
- outage factors
- operations and maintenance cost
- heat rates
- expected generation output
- discount rates

- required environmental improvements

NL Hydro used the Strategist planning model to enumerate the different combinations and identify the least cost ones. The process produced two generation expansion alternatives: the Isolated Island alternative and the Interconnected Island alternative.

Navigant reviewed Nalcor's implementation of Strategist, with a focus on the major resources (Muskrat Falls, Labrador-Island Link, and Holyrood pollution abatement upgrades and life extension projects). Inputs in the model were consistent with those presented by Nalcor in exhibits presented to the Public Utilities Board.[32]

4.3 Constraints Used in the Modeling

The chosen generation expansion plans were selected based on the minimization of revenue requirement, modeled as the "minimization of utility cost" objective function. As there was only one objective function used, its weighting was 100 per cent.

Nalcor constrained the timing for the Muskrat Falls project and LIL in the Interconnected Island alternative. Similarly, Nalcor constrained the timing for Holyrood pollution abatement investment and life extension upgrades in the Isolated Island alternative. The timing for the pollution abatement investment was based on provincial policy as discussed previously.

Nalcor constrained the entrance of wind in the Isolated Island alternative to 25 MW in 2014. Nalcor wanted to limit the total system wind capacity to 80 MW, based on the 2004 study which found that higher amounts would likely result in spilling at the hydroelectric facilities.[33]

Nalcor conducted an initial optimization for twenty years, rather than attempting to optimize through 2067. Optimizing plans over the entire time horizon would have taken excessive amounts of clock time to complete, due to the astronomical number of combinations that the PROVIEW module of Strategist would create. Nalcor identified specific units, such as the three hydroelectric options in the Isolated Island alternative, that were part of the least cost plans in this initial analysis. Nalcor then locked in those options and allowed Strategist to optimize over the remaining portion of the time horizon and determine the appropriate mix of future generation units.

32. Nalcor's use of the Strategist model in developing the two generation expansion alternatives is consistent with generally accepted utility practice.

[32] Nalcor. Letter from Nalcor to Board of Commissioners of Public Utilities. July 6, 2011.

[33] Newfoundland and Labrador Hydro. "An Assessment of the Limitations for Non-Dispatchable Generation on the Newfoundland Island System. 2004.

5 Results and Sensitivity Analysis

Based on the assumptions, inputs and analysis as described in the previous sections, and as modeled in Strategist, the CPWs for the two generation expansion alternatives are shown below.

Table 14: CPW for Generation Expansion Alternatives

Generation Expansion Alternative	Cumulative Present Worth (CPW) 2010$ millions
Isolated Island	$8,810
Interconnected Island	$6,652
Preference for Interconnected Island	**$2,158**

As shown above, Nalcor projects that developing the Interconnected Island alternative will result in lower utility costs for customers of $2.2 billion in present value terms through 2067 as compared to the Isolated Island alternative.

33. **The CPWs for the generation expansion alternatives fairly represent the costs that would be incurred under the alternative supply futures. Therefore, the $2.2 billion CPW preference for the Interconnected Island alternative is a reasonable estimate of the expected cost difference between the two alternatives.**

To study the impact that variations of key assumptions would have on the CPW preference for the Interconnected Island alternative, Nalcor and Navigant have undertaken a number of sensitivity analyses.

5.1 Indifference Analysis

To estimate the conditions under which the two alternatives would yield an equivalent CPW – for which Nalcor would presumably be indifferent to the decision all other things being equal – two analyses were run. One analysis reduced fuel prices for each year of the analysis period by a fixed percent necessary to yield equivalent CPWs for the two alternatives. The other analysis reduced load – starting in 2013 – by a fixed amount each year to also yield equivalent CPWs.

Holding all other assumptions unchanged, the CPWs of the two generation expansion alternatives would be equivalent under either of the following cases:

1. Fuel costs are 44 percent lower than Nalcor base forecast in each year of the forecast. This would represent fuel prices that are less than the PIRA Low forecast.

2. Island load drops by 880 GWh starting in 2013 continuing through the remainder of the analysis period. This would represent a step reduction in Nalcor's load of more than 10 percent in a single year.

5.2 Sensitivity Analysis

To explore the sensitivity of key risks and uncertainties on the CPW preference for the Interconnected Island alternative, Nalcor and Navigant ran a number of different sensitivity cases as follows:

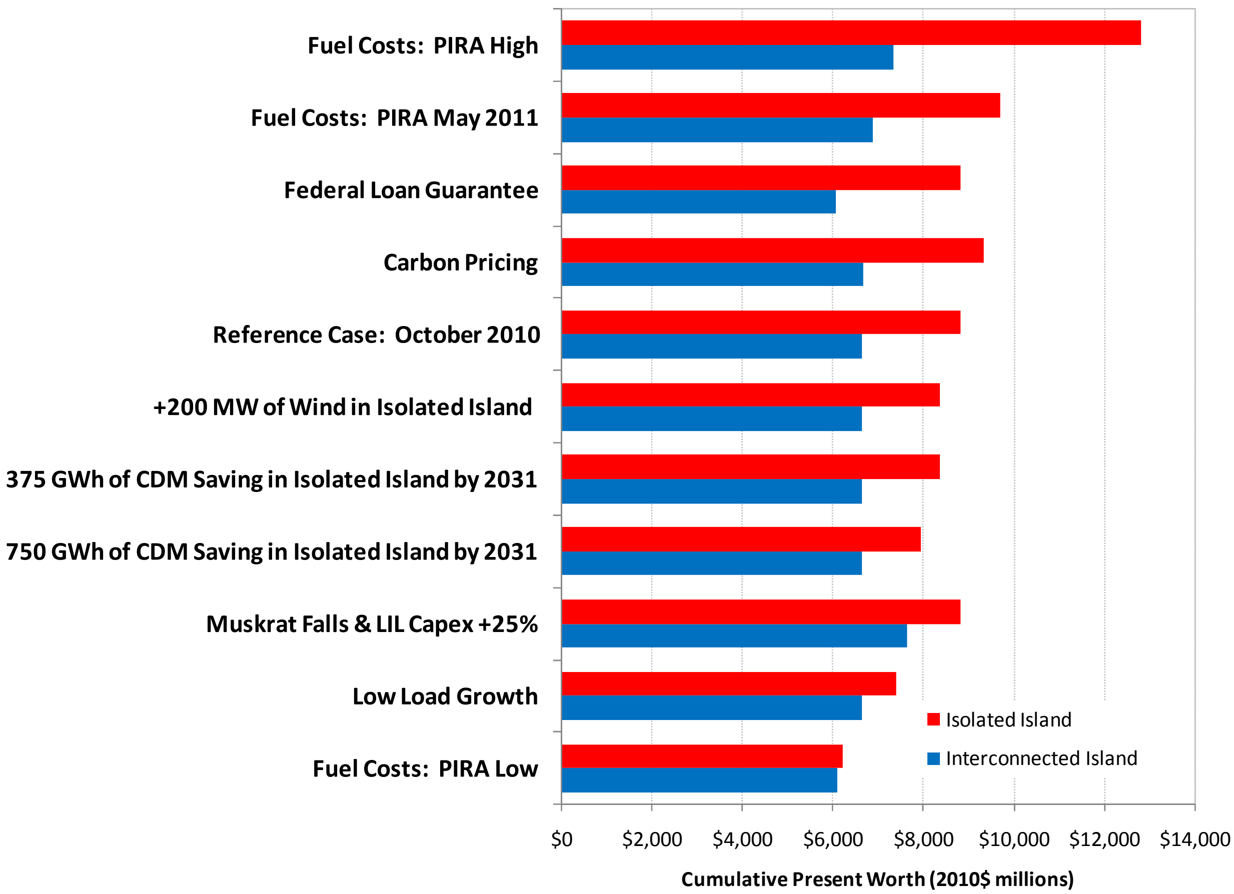
- Different fuel costs
- Low load growth
- Higher capital costs for Muskrat Falls and LIL
- Introduction of carbon pricing
- Pursuit of CDM in Isolated Island
- 200 MW increase in wind in Isolated Island, and
- Federal Loan Guarantee.

Many of these were considered by Nalcor for possible inclusion in the reference case analysis for DG2, but were rejected as being too uncertain to include in the reference case. In some cases, new information significantly increases the probability of a particular sensitivity case being realized – such as the Federal Loan Guarantee. Given the recently announced Memorandum of Agreement, Nalcor and Navigant believe that the impact of the federal government loan guarantees on the CPW preference for the Interconnected Island alternative should be analyzed. In fact, the certainty of this occurring has increased to a point that it should be included in the reference case for the DG3 decision.

All of the sensitivity cases reflect uncertainties that could materially impact the CPW difference between the alternatives. For this reason, Nalcor and Navigant believe it is important to provide this information.

The resultant CPW estimates for these sensitivity cases are presented in Figure 20 along with the October 2010 DG2 input reference case.

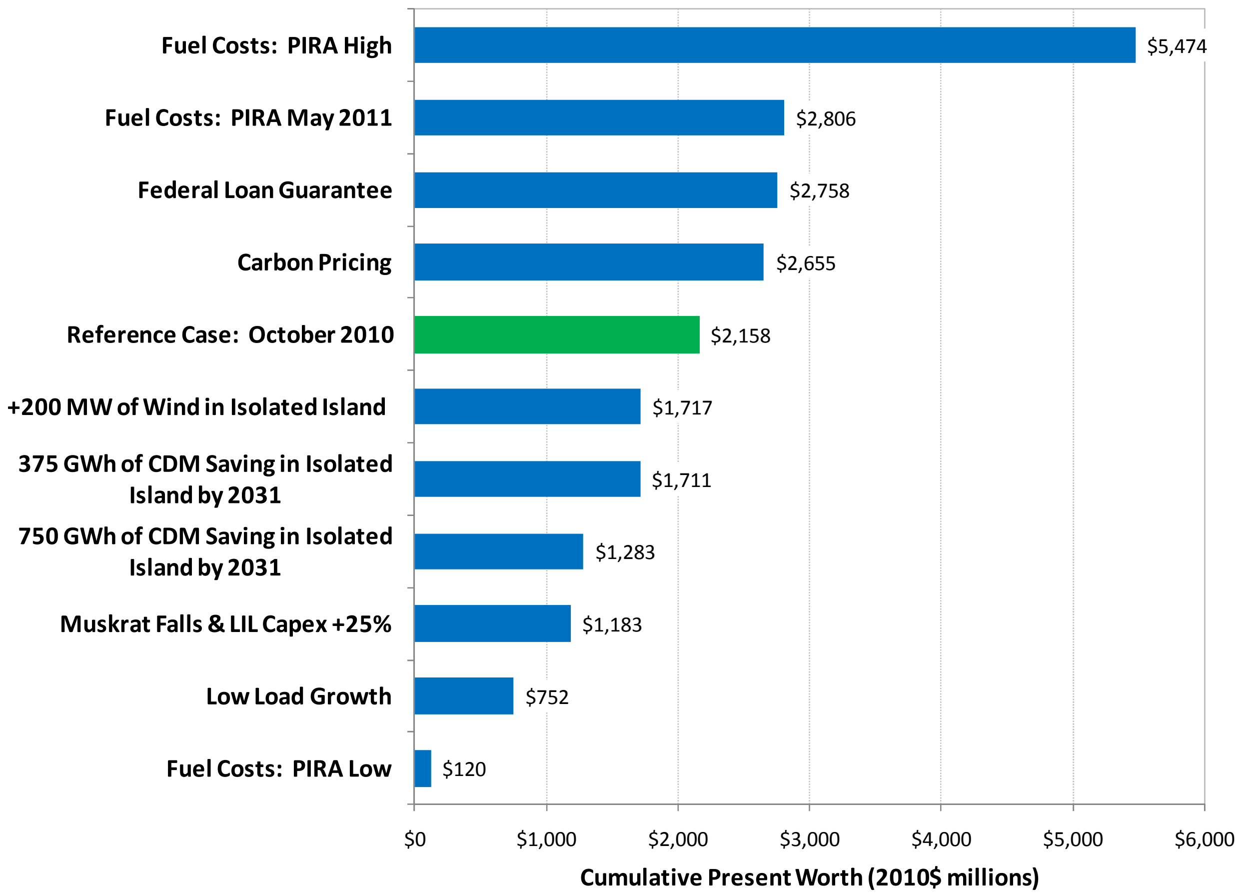
Figure 20: Sensitivity Results: Interconnected Island and Isolated Island CPW



Source: Nalcor. MHI-Nalcor 41. August 11, 2011 and Navigant.

The difference between these various CPW estimates for the two alternatives under the various sensitivity cases is shown in Figure 21.

Figure 21: Sensitivity Results: CPW Difference between Alternatives



Source: Nalcor. MHI-Nalcor 41. August 11, 2011 and Navigant.

It is particularly noteworthy that all of the sensitivities resulted in a CPW preference for the Interconnected Island alternative. This clearly indicates that the DG2 decision preference for the Interconnected Island alternative was robust given the underlying risk and uncertainty in key assumptions as well as possible refinements to the Isolated Island alternative as identified by Navigant. Further, currently available information – specifically, the updated May 2011 PIRA fuel forecast, recent federal loan guarantee commitment and announcement of the Maritime Link to Nova Scotia – increases the preference for the Interconnected Island alternative.

Details of the sensitivities cases analyzed by Nalcor and Navigant are provided below.

Fuel Costs

Each of the fuel cases reflects a trajectory for oil prices under different macroeconomic conditions. For example, the PIRA High forecast for the underlying West Texas Intermediate crude oil is approximately 3.5 times higher than the PIRA Low forecast for the period 2010 through 2025.

The PIRA High and Low forecasts both have a similar probability of occurring. While it is possible that fuel prices could be sufficiently low to render a CPW preference of only $120 million for the Interconnected Island alternative under the PIRA Low forecast, it is equally probable that fuel prices could be sufficiently high for the Interconnected Island alternative to have a $5,474 million CPW preference over the Isolated Island alternative under the PIRA High forecast. Also, a more recent long-term PIRA fuel price forecast as of May 2011 yields a $2,806 million CPW preference for the Interconnected Island alternative.

Load Growth

The low load growth case reflects a 50 percent reduction in the rate of annual load growth starting in 2015, after Vale's Long Harbour operation reaches full production. This case yields a $752 million CPW preference for the Interconnected Island alternative.

The low load growth is assumed not to affect annual demand and thus the timing of generation additions was not revised. To the degree that demand would be affected under a low load growth scenario, it is likely that CTs planned in both alternatives for the latter years of the analysis period could be deferred or avoided resulting in slightly lower CPWs for both alternatives.

Capital Costs

The "*Muskrat Falls and LIL Capex + 25%*" reflects the impact of higher capital costs for the two LCP projects. This case yields a $1,183 million CPW preference for the Interconnected Island alternative.

Carbon Pricing

Due to continuing uncertainty of federal regulation of atmospheric emissions, Nalcor chose not to include any impact from possible carbon pricing in its reference case analysis. Notwithstanding, Navigant believes that some form of greenhouse gas (GHG) emission mitigation legislation is possible over the analysis period. To address this possibility, Nalcor and Navigant estimated the potential impact of projected carbon pricing coming into effect in 2017[34] using carbon price projections developed by the US Department of Energy as an analysis of the Waxman-Markey Legislation. The carbon price forecast is shown in Figure 22.

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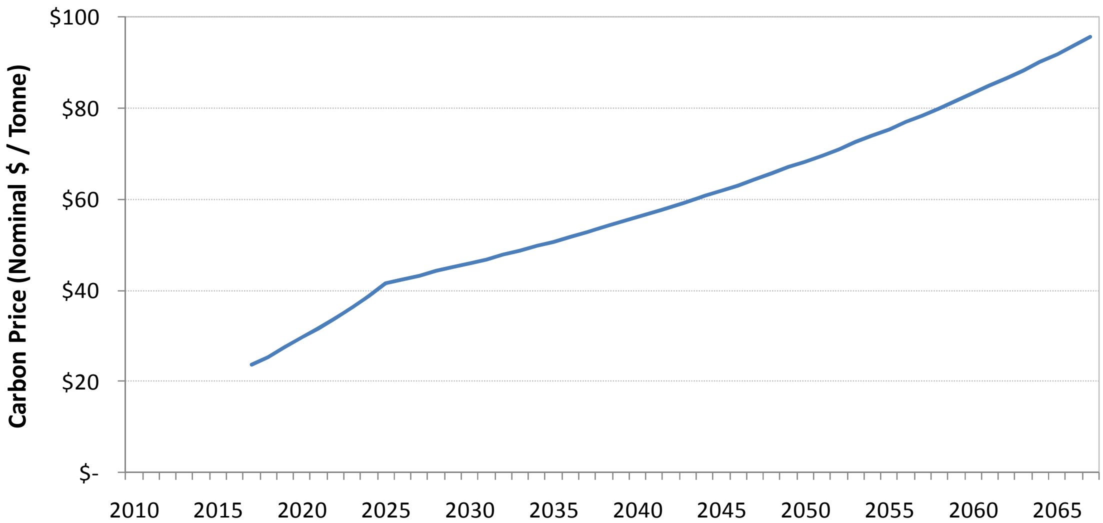
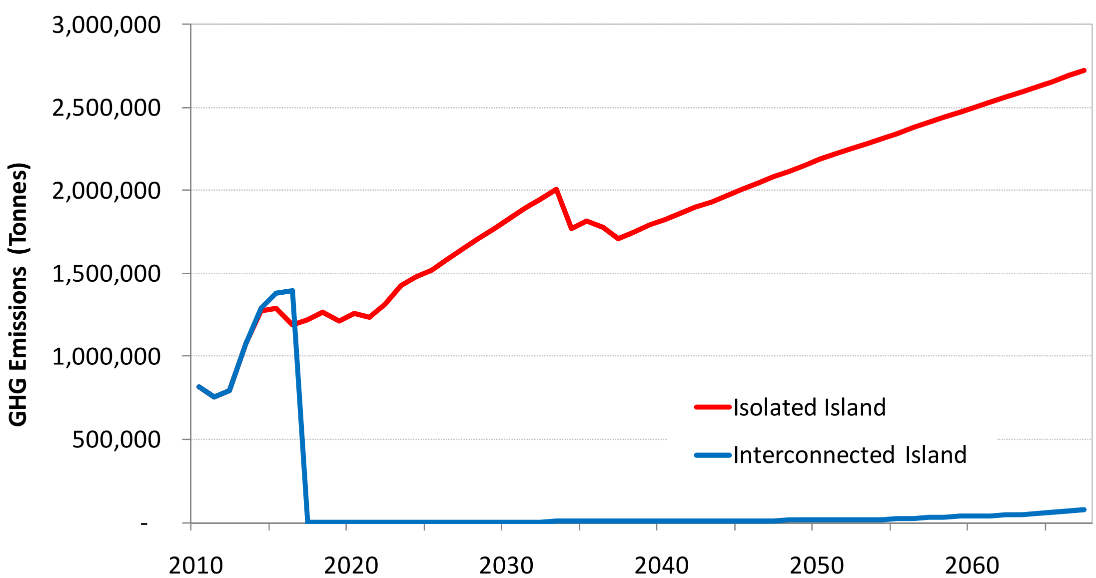
[34] If carbon pricing was introduced prior to 2017, it would increase the CPW of both alternatives by approximately the same amount given the similar levels of GHG emissions for both alternatives through the end of 2016.

Figure 22: Projected Carbon Prices



Given the level of GHG emissions in the Isolated Island alternative, as shown in Figure 23, the introduction of any form of carbon pricing would increase thermal production costs and have a significant impact on the CPW for the Isolated Island alternative. Post 2017, the GHG emissions in the Interconnected Island alternative are essentially zero until the later part of the analysis period when relatively limited GHG emissions from CTs operating infrequently to serve peak demand are expected.

Figure 23: GHG Emissions: Interconnected Island and Isolated Island Alternatives

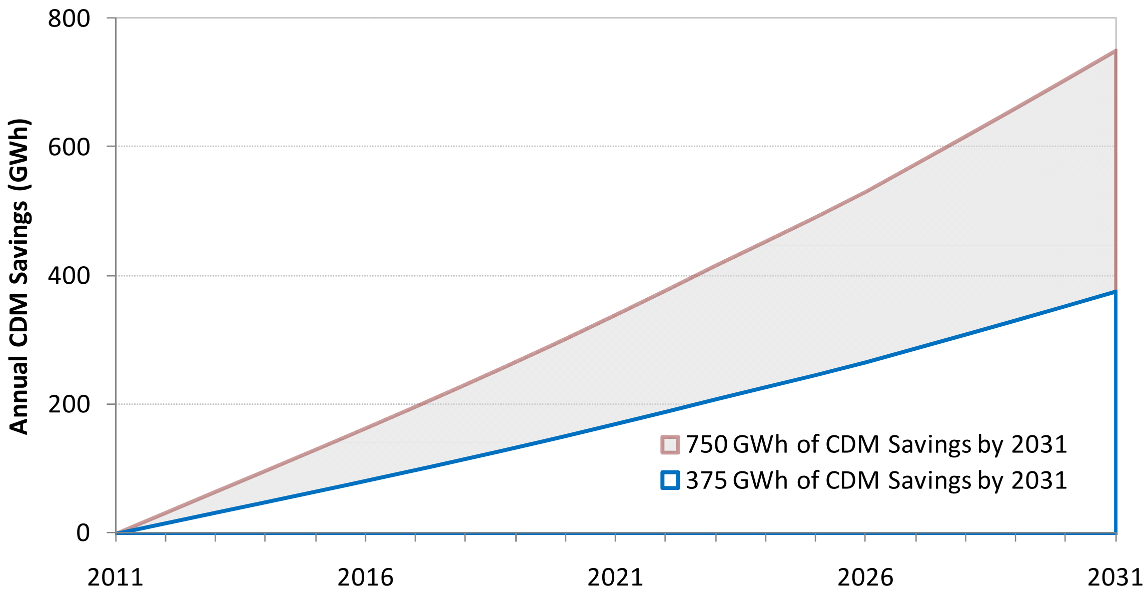


This case yields a $2,655 million CPW preference for the Interconnected Island alternative.

CDM in Isolated Island

Nalcor and Navigant explored two CDM savings sensitivity cases reflecting what, in Navigant's opinion, could be considered as upper and lower planning estimates. Marbek's Lower Achievable Potential represents the average of these two estimates. Figure 24 presents the cumulative reduction in annual energy consumption under these two estimates. Where actual CDM savings fall in this range (or possibly below the lower planning estimate) would be very dependent on the degree to which there was a supportive government policy framework, including strong efficiency codes and standards, and a receptive customer base, factors that are out of NL Hydro's and Newfoundland Power's control.

Figure 24: Cumulative Annual Energy Savings for CDM Planning Estimates



CDM programs are not free – there are typically incentive costs, marketing costs, administrative costs and evaluation costs associated with these programs. To estimate what these costs would be, Navigant assumed that the costs of implementing the programs would be approximately $60 per MWh of savings realized. Navigant believes that this level of program costs is a reasonable estimate for the costs necessary to realize the level of savings under the CDM cases.

This upper planning estimate of CDM savings (750 GWh by 2031) yields a $1,283 million CPW preference for the Interconnected Island alternative and the lower planning estimate of CDM savings (375 GWh by 2031) yields a $1,711 million CPW preference for the Interconnected Island alternative.

Although Nalcor and Navigant did not explore the impact of CDM on the Interconnected Island case, it is important to note that NL Hydro would be able to monetize the conserved energy through sales to other markets, particularly with the inclusion of the Maritime Link[35] to Nova Scotia and transmission access into New Brunswick and New England.

200 MW Increase in Wind in Isolated Island

In this case, an incremental 100 MW of wind is added in the Isolated Island alternative in 2025 and a further 100 MW of wind is added in 2035 provided that the wind capacity system constraints in the 2004 study can be addressed cost-effectively. As described in section 2.3.1, the wind projects are not started earlier because additional wind output will not be expected to displace fossil output most of the time until approximately 2025. Prior to 2025, Nalcor expects that additional wind would only result in partial displacement of fossil output and could trigger additional spill from the existing hydroelectric facilities. Alternatively, additional wind prior to 2025 could be subject to curtailment to mitigate spill from existing hydroelectric, but this would increase the effective cost of wind power. For conservatism, this analysis also assumed that all of the additional wind power would be located on the Avalon Peninsula and, as result, would not require any significant transmission upgrades.

This case yields a $1,717 million CPW preference for the Interconnected Island alternative.

Although the focus of the above analysis is on wind in the Isolated Island alternative, it is important to note that Nalcor would have capacity to integrate significantly more than 200 MW of wind in the Interconnected Island alternative given the performance characteristics of Muskrat Falls.

Federal Loan Guarantee

In August 2011, the federal government committed to providing a federal loan guarantee for the Muskrat Falls (including associated Labrador transmission), Labrador-Island Link (and Maritime Link to Nova Scotia). The loan guarantee would have the effect of lowering the interest rate on the debt for Muskrat Falls, Labrador-Island Link to a level approximately equal to that for federal government debt.

This case yields a $2,758 million CPW preference for the Interconnected Island alternative.

Combining Sensitivity Cases

Nalcor and Navigant did not run any "combination" sensitivity cases, but it is important to recognize that there are specific combinations that are possible and other combinations that are not possible.

[35] http://www.gov.nl.ca/lowerchurchillproject/backgrounder_2.htm

For example, a combination of 1) introduction of carbon pricing, and 2) provision of the federal loan guarantee would be possible and would result in a higher CPW preference for the Interconnected Island alternative than the individual sensitivity case results.

An impossible combination would be CDM and more wind generation both applied in the Isolated Island alternative. The reason this combination is impossible is that system load growth in Nalcor's reference case results in higher levels of thermal generation over time which, in turn, enable wind generation to be added when it can displace thermal generation most of the time (100 MW in 2025 and a further 100 MW in 2035). Under the CDM sensitivity case, there is lower load growth through 2026 and, as a result, there would be insufficient thermal production to enable wind to be added without increasing the probability of spill at NL Hydro's existing hydroelectric generation facilities.

Generation Expansion Variants

As discussed in previous sections, Nalcor determined the CPW for variants on the two primary generation expansion alternatives, including:

- Deferral of the Labrador-Island Interconnection to 2041 and supply to the Island from Churchill Falls (as a variant to the Interconnected Island alternative)
- Importing electricity via a transmission link from Newfoundland to Atlantic Canada and New England for the purposes of accessing power and energy to meet the Island's electricity requirements (as a variant to the Interconnected Island alternative), and
- Early Replacement of Holyrood with a CCCT (as variant to the Isolated Island alternative).

The CPW differences for these variants are summarized in Table 15.

Table 15: CPW Differences for Generation Expansion Variants

Variant	Incremental CPW	Primary Drivers of CPW Difference
Deferral of the Labrador-Island Interconnection to 2041 and supply to the Island from Churchill Falls	$1.7 billion more than the base Interconnected Island alternative	Fuel costs through 2041 and capital costs for early replacement of the Holyrood facility with a CCCT in 2017
Importing electricity via a transmission link	$1.5 billion more than the base Interconnected Island alternative	Higher transmission costs and charges
Early Replacement of Holyrood with a CCCT	$0.3 billion more than the base Isolated Island alternative	Higher costs and lower energy content (5.77 MMBtu per barrel) of No. 2 fuel as compared with No. 6 fuel (6.25 MMBtu per barrel).

> **34. The sensitivity cases run by Nalcor and Navigant capture the key risks in the assumptions for, and the impacts of potential refinements to, the generation expansion alternatives.**

> **35. All of the sensitivity cases maintained the CPW preference for the Interconnected Island alternative. This clearly indicates that the DG2 decision preference for the Interconnected Island alternative was robust given the underlying risk and uncertainty in key assumptions in the generation expansion alternatives.**

> **36. The CPW preference for the Interconnected Island alternative is maintained after adding more wind or CDM to the Isolated Island alternative.**

> **37. Current information, and specifically the updated May 2011 PIRA long term fuel forecast and the recently announced federal loan guarantee commitment, increases the CPW preference for the Interconnected Island alternative.**

5.2.1 Other Evaluation Criteria

The results and sensitivity analysis presented above relate primarily to the "cost to ratepayers" criterion as used by Nalcor in its evaluation of the Island supply options. The other criteria used by Nalcor were:

- Security of supply and reliability
- Environmental responsibility, and
- Risk and uncertainty.

A comparison of the two alternatives across these criteria are provided below.

Security of Supply and Reliability

Nalcor has investigated the level of exposure and unserved energy due to transmission failures in both alternatives. Based on the Nalcor analysis, in the worst case scenarios (transmission failures occurring in the worst two week window in terms of system load and available generation) both alternatives yield unsupplied energy of less than 1 percent of the annual energy forecast which represents increased security of supply and reliability as compared to the current situation. Further, with inclusion of the Maritime Link to the Interconnected Island alternative, the security of supply and reliability for this alternative will be substantially improved.

Environmental Responsibility

As shown in Figure 23, GHG emissions would be significantly higher under the Isolated Island alternative than the Interconnected Island alternative due to the significantly higher level of fossil fuel consumption in the Isolated Island alternative.

Risk and Uncertainty

The significantly higher level of fossil fuel consumption in the Isolated Island alternative also contributes to significant cost risk and uncertainty for this alternative. As shown in Figure 21, the CPW for this alternative varies by more than $5 billion between the PIRA Low and PIRA High forecast. Further, the Isolated Island alternative is subject to considerable risk and uncertainty related to environmental legislation and regulation – both in terms of ability to operate the planned thermal facilities and costs to operate these facilities (as impacted by introduction of carbon pricing).

38. Relative to the Isolated Island alternative, the Interconnected Island alternative is also expected to provide similar levels of security and reliability, significantly reduced GHG emissions and significantly less risk and uncertainty.

39. The criteria used by Nalcor in the Island supply decision were reasonable and consistent with generally accepted utility practices.

6 Review of the Rate Impact Analysis

Estimates of the overall wholesale costs associated with developing the Interconnected Island alternative versus the Isolated Island alternative were prepared by Nalcor. These costs are subsequently recovered from NL Hydro's customers (i.e. Newfoundland Power and industrial customers). Nalcor projects that developing the Interconnected Island alternative will result in lower utility costs for customers of $2.2 billion in present value terms through 2067 as compared to the Isolated Island alternative.

The scope of the wholesale rate[36] impact analysis is with respect to the bulk generation and transmission grid of the Island and includes all cost of service components such as operating costs, depreciation and return on rate base. This entails combining the existing rate base and its associated revenue requirements with the incremental annual revenue requirements derived from the Strategist generation expansion plans. The revenue requirement associated with retail distribution is assumed to be identical in both the Isolated Island and Interconnected Island alternatives.

6.1 Approach Used to Quantify Rate Impacts

Nalcor used a traditional revenue requirement approach in evaluating the rate impacts associated with various supply alternatives. A revenue requirement was estimated annually for each supply alternative. The revenue requirement is defined in the following equation:

Revenue Requirement = *Operating and Maintenance Expenses +*
Power Purchases +
Fuel Costs +
Depreciation +
Interest +
Return on Equity

The overall approach to calculating the revenue requirement is consistent with what has been used by the PUB for regulatory filings in the past and consistent with the approach commonly used in other jurisdictions.

6.2 Assumptions used in Calculating the Revenue Requirement

A number of assumptions were used by Nalcor for estimating the rate impacts associated with the development of the Isolated Island and Interconnected Island alternatives. Navigant reviewed these assumptions which are discussed below.

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[36] For the purposes of this review, NL Hydro "wholesale rate" is the total annual regulated revenue requirement for the Island grid which would subsequently be essentially recovered from all of NL Hydro's customers on the Island grid.

6.2.1 Capital Structure

NL Hydro's regulated capital structure is composed of:

- Equity;
- Debt; and
- Liabilities associated with the company's post-retirement benefits which NL Hydro is obligated to provide to employees.

Return on Equity (ROE)

The company's ROE is projected to increase from a currently approved 4.47 percent to a long-term rate in the range of 9 percent to 10 percent. The explanation for the increase in the ROE is a directive by the Province where NL Hydro is to be afforded a ROE which is equal to that of an investor-owned utility.[37]

Debt

For both the Interconnected Island and Isolated Island alternatives, projections of the cost of debt range from a current embedded cost of 8.8 percent decreasing to approximately 7.5 percent in the long-term. The embedded cost of debt takes into account existing debt combined with new debt projections. The cost of new debt is based upon the cost of borrowing for the Province which, in turn, is based on projections for reference interest rates obtained from the Conference Board of Canada (CBoC) as of January, 2010. The average cost of new NL Hydro debt is 7.35 percent for the CBoC projection period.

Weighted Average Cost of Capital

For the purposes of determining annual revenue requirements, NL Hydro established a target debt to debt plus equity ratio of 75 percent resulting in a weighted average cost of capital of approximately 8 percent.

6.2.2 Operations & Maintenance Expenses

Operating and Maintenance (O&M) Expenses are composed of:

- the existing base of regulated NL Hydro O&M with escalation applied; plus
- Incremental O&M as calculated by Strategist for the generation expansion alternatives.

[37] Press Release from the Government of Newfoundland and Labrador dated June 17, 2009.

6.2.3 Fuel Expense

NL Hydro fuel expense is driven by the fuel price forecasts as presented in section 3.3.3, combined with the thermal production by source as determined by Strategist for the alternative generation expansion plans.

6.2.4 Purchased Power Expense

Purchased power expense is composed of:

- Forecasted purchases from a number of hydroelectric and wind Non-Utility Generators (NUG) was determined based upon the commercial terms of their contracts; plus
- Forecasted purchases from Muskrat Falls as described in section 3.3.9.

6.2.5 Labrador-Island Link Transmission Services

The cost of the Labrador-Island Link was modelled as a regulated utility asset and was included in NL Hydro's overall annual revenue requirements.

6.2.6 Depreciation Expense

The following lives were used to determine depreciation expense for various classes of assets.

Table 16: Depreciation Lives for Various Classes of Assets

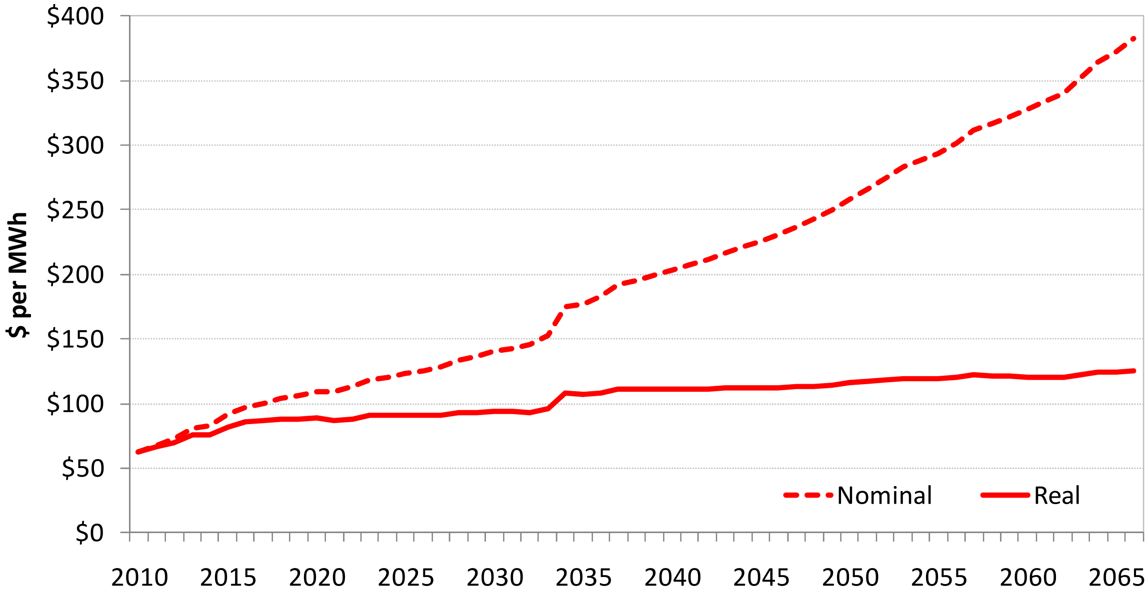
Technology	Depreciation Life (Years)
Gas Turbines	25
Hydraulic Generation	60
Combined-Cycle Combustion Turbine	30
Wind	20
Labrador-Island Transmission Link	50

6.3 Analysis of Results

6.3.1 Isolated Island Alternative

The base Isolated Island alternative assumes the Island of Newfoundland remains electrically isolated from the North American electricity grid. Figure 25 below illustrates the revenue requirement expressed on a unit cost basis, in both nominal and real (before considering inflation) basis over the analysis period.

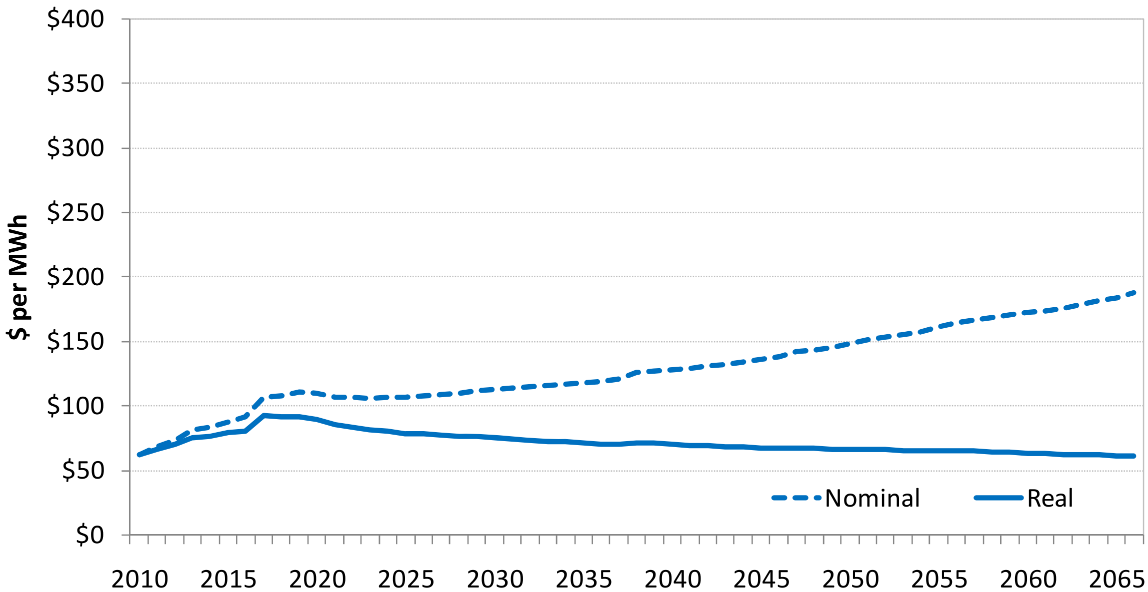
Figure 25: Average Revenue Requirement of the Isolated Island Alternative



6.3.2 Interconnected Island Alternative

The Interconnected Island alternative assumes 1) an interconnection of the Island of Newfoundland with the North American electricity grid through the Labrador-Island Link and 2) provision of energy supply from Muskrat Falls to the Island. Figure 26 below presents the revenue requirement on a unit cost basis on a nominal and real (before considering inflation) basis over the analysis period.

Figure 26: Average Revenue Requirement of the Interconnected Island Alternative

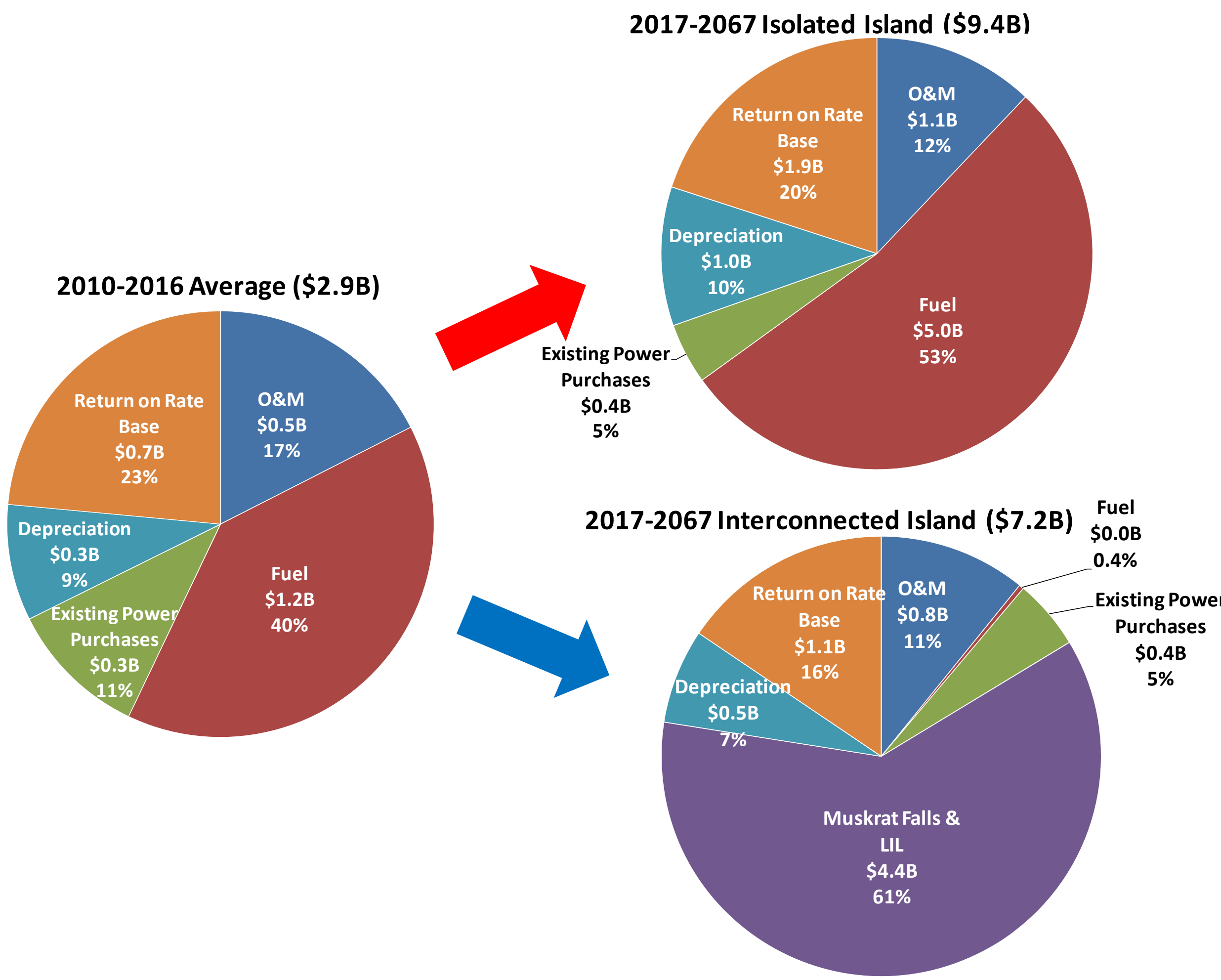


As shown in Figure 26, a gradual decrease in real average unit costs occurs for the Interconnected Island alternative and real rates at the end of the analysis period are essentially the same as at the beginning of the analysis period.

6.3.3 Components of Revenue Requirements

The composition of the revenue requirements for the period from 2010 – 2016 (when the two alternatives are essentially the same) and from 2017 – 2067 for the two alternatives is shown in Figure 27. Note that the Muskrat Falls and LIL component of the Interconnected Island alternative include depreciation, Return and O&M for these facilities. Return or Return on Rate Base represents Interest on Debt and Return on Equity.

Figure 27: Composition of Island Revenue Requirements (CPW 2010$)



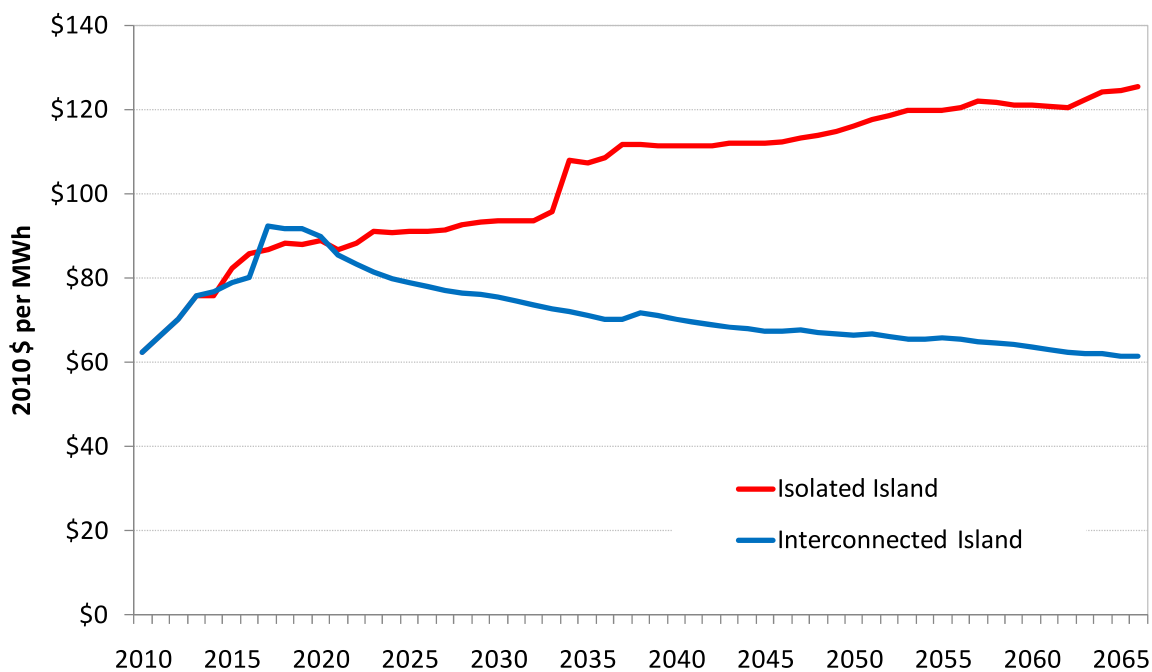
Source: Nalcor

As shown in Figure 27, the Interconnected Island alternative represents a fundamental change in the utility cost structure for the Island. In contrast to the Isolated Island alternative where fuel costs represent more than half of the revenue requirements, fuel costs are essentially zero in the Interconnected Island alternative. Wholesale electricity rates will be much more stable and certain in the Interconnected Island alternative.

6.4 Summary

Figure 28 illustrates the projected rate impacts in real 2010$ terms (before considering inflation) of the Isolated Island alternative versus Interconnected Island in Nalcor base case analysis. Note that rates in the Interconnected Island alternative are lower than rates in the Isolated Island alternative from 2020. By 2067, rates in the Interconnected Island alternative will be less than 50 percent of rates in the Isolated Island alternative.

Figure 28: Average Real Rate per MWh



40. The Interconnected Island alternative represents a fundamental change to a more stable and certain utility cost structure for the Island by minimizing thermal generation and its associated fuel cost uncertainty.

41. Nalcor's wholesale electricity rate impact analysis accurately reflects the rate projections and provides a reasonable basis for assessing unit cost trends with respect to the two alternatives.

42. Short-term increases in real (before considering inflation) wholesale electricity rates would occur over the next few years under either alternative. Beyond 2017, the wholesale electricity rates for the Interconnected Island alternative decline in real terms.

43. Wholesale electricity rates are lower in the Interconnected Island alternative than the Isolated Island alternative except for a brief period at the end of this decade. This short-term issue could be mitigated through ratemaking.

7 CONCLUSIONS

Navigant has concluded that Nalcor's consideration and screening of the supply options as well as the assumptions used by Nalcor regarding these options were reasonable and consistent with generally accepted utility practices. Nalcor's process to evaluate the supply options and estimate the rate projections under the two alternatives was also found to be reasonable and consistent with generally accepted utility practices.

Navigant has concluded that the CPW calculated by Nalcor for each of the generation expansion alternatives fairly represent the costs that would be incurred under the alternative supply futures. Thus, the $2.2 billion preference for the Interconnected Island alternative, as estimated by Nalcor in the DG2 decision gate, is a reasonable estimate of the expected cost difference between the two alternatives.

To explore the sensitivity of the CPW difference between the two alternatives to changes in the supply options or assumptions, Nalcor and Navigant analyzed a number of sensitivity cases covering:

- different fuel price forecasts
- lower load growth
- additional wind generation
- introduction of carbon pricing
- aggressive CDM, and
- higher capital costs and the recently announced Federal Loan Guarantee for Muskrat Falls and the LIL.

All of the sensitivity cases resulted in a CPW advantage for the Interconnected Island alternative. This clearly indicates that the DG2 decision preference for the Interconnected Island alternative was robust given the underlying risk and uncertainty in key assumptions.

7.1 Is the Interconnected Island the Least Cost Supply Option for Newfoundland?

Based on its independent review, Navigant has concluded that the Interconnected Island alternative is the long-term least cost option for the Island of Newfoundland. Relative to the Isolated Island alternative, the Interconnected Island alternative is also expected to provide similar levels of security and reliability, significantly reduced GHG emissions and significantly less risk and uncertainty. The Interconnected Island case also provides a gradual decrease in real (adjusted for inflation) average wholesale electricity rates for the Interconnected Island alternative.