Date : 10/12/2012 9:07:24 PM
From : "Paul Wilson"
To : "Bown, Charles W."
Cc : "Danny Northcott"
Subject : MHI DG3 Wind Assessment Report - Draft
Attachment : Final Draft Report - NFL3 Assessment of Wind for Island of Newfoundland.pdf;

Hello Charles, please find attached a new draft of the MHI wind assessment report.

There are numerous editorial changes to address the items noted by Nalcor on the last review. The major ones include:

- The Backup CT fuel costs are broken out in the CPW calculation table. Even if the fuel costs are overstated the wind/backup CT options is still more expensive than the Isolated Island option.
- Language in the exec summary and conclusions has been strengthened around the risks, the high penetration levels, and that this mode of operation has never been demonstrated in an Isolated Island grid. A statement has been added that more study is needed to determine the technical feasibility for grid integration.
- A statement is made that the 279 MW level is appropriate for the Isolated Island grid as per Hatch's 2012 study.
- A note has been added to the conclusions and exec summary that the wind scenarios are still largely a thermal plan once Holyrood is replaced.
- NLH is now consistently referred to as Nalcor.
- Language throughout the report differentiating between capacity and energy penetration has been cleaned up.
- The Holyrood historical energy chart has been removed and the entire section 3.3.9 has been revisited to make it more understandable.

Please send a copy to Nalcor for their review. I will keep in contact next week to followup.

My regards,

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Manitoba HYDRO INTERNATIONAL

Decision Gate 3

Review of the Wind Study for the Isolated Island of Newfoundland

October 2012

Decision Gate 3

Assessment of Wind for the Isolated Island of Newfoundland

DRAFT

Prepared for:
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The Minister of the Department of Natural Resources
Government of Newfoundland and Labrador

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October 12, 2012

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

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Executive Summary

Manitoba Hydro International Ltd. was engaged by the Government of Newfoundland and Labrador, Department of Natural Resources to provide a review, opinion and commentary on the reasonableness of the reports provided by Nalcor Energy on the subject of wind in the Isolated Island option. MHI study goals were:

1. Complete a due diligence review of the studies provided by Nalcor to determine if the study goals have been met.

2. Utilizing information provided by Nalcor, and other literature as appropriate, provide a narrative that addresses the following questions: "In an isolated island scenario, can sufficient wind be developed to replace the Holyrood Thermal Generating Station and meet future demand? Is this a technically feasible and economic alternative to Muskrat Falls and the Labrador Island Link?"

The two reports on the development of wind for the Isolated Island of Newfoundland were reviewed; Hatch's Wind Integration Study – Isolated Island, and Nalcor's report on Wind Integration – Voltage Regulation and Stability Analysis. Both reports are technically sound, meet their study goals, and were performed in accordance with good utility practices.

To meet the second MHI study goal, a high-level engineering exercise was performed to evaluate two theorized options for replacement of the Holyrood Thermal Generation Station for the Isolated Island of Newfoundland with large-scale wind development. Possible locations for the wind farms were selected based on available wind energy maps with consideration to proximity of load centers. Technical challenges associated with exceeding 10% wind penetration were met with theoretical technical solutions including the widespread application of synchronous condensers, and backup Combustion Turbines (CTs).

A wind solution to replace the base load units at the Holyrood Thermal Generating station exceeds existing utility experience in terms of wind penetration. The peak load for the Isolated Island is forecasted to be 1861 MW in 2025 where a 1379 MW wind solution proposes a 75% penetration factor of capacity, and 51% by energy. It is important to note that the highest wind penetrations today are in the range of 20% by energy, and only in the interconnected parts of the grid. In this report, wind penetration percentages will be wind energy as a percentage of total energy produced in that year, unless otherwise noted.

Without further detailed study, the new wind generation cannot be assigned a firm capacity credit on the Island of Newfoundland; thus, this generation must be backed up by firm dispatchable energy sources. The two options were explored in this assessment in order to meet this requirement; deployment of low capital but high-energy cost backup CT generators, and deployment of a massive 6 TWh battery bank.

A Cumulative Present Worth analysis was performed on each of the large scale wind development scenarios and compared against the existing Nalcor CPW metrics for the Muskrat Falls Interconnected and Isolated Island options. The wind and battery scenario is the most costly option, while the wind and thermal backup CT option is less, but is still more costly than the Isolated Island option. The CPW result table from this assessment is shown in Table 1.

Table 1: Cumulative Present Worth of Studied Scenarios

	Cumulative Present Worth (Billions in 2012)			
CPW Cost Component	**Interconnected Option**	**Isolated Island Option**	**Wind & Thermal Scenario**	**Wind & Battery Scenario**
Fixed Charges	$0.32	$2.56	$7.27	$14.61
Operating Costs	$0.26	$0.75	$1.29	$1.18
Fuel Costs	$1.32	$6.71	$0.87	$0.87
Backup CT Fuel Costs	$0	$0	$1.67	$0
Power Purchases	$6.47	$0.76	$0.76	$0.76
Total	**$8.37**	**$10.78**	**$11.86**	**$17.43**

Based on these screening level study findings (at an AACE Class 4 estimate), and the risks inherent in such a massive wind development, MHI does not recommend that wind options beyond a 10% penetration level, as recommended by the 2012 Hatch study, be pursued at this time. Investment in the Muskrat Falls Interconnected Option provides a firm supply and an opportunity to monetize the excess energy once another interconnection is made. The wind power scenarios do not provide the same value for the $11.86 or $17.43 billion costed over the study period. One must note that the wind scenarios examined are still largely a thermal generation resource plan once the Holyrood Thermal Generating Station is replaced.

One must be cautioned on the nature of the outcomes of this assessment as a great deal more work is required to technically evaluate the feasibility of the Holyrood Thermal Generating Station wind replacement scenario. That is, in order to determine if system voltages, loadings and frequency are within acceptable limits the additional wind power, more simulation studies must be undertaken. These studies could lead to the addition of more equipment such as static VAR compensators, reactors, new protection and control systems, etc. The scenario and mode of wind operation theorized in this study has not been demonstrated elsewhere in the world for an isolated island grid. In addition, the 1379 MW wind alternatives have a higher risk profile considering the high levels of wind penetration proposed together with the many issues that need to be studied.

MHI finds that large-scale wind development, as a replacement for Holyrood Thermal Generating Station is not a least cost option at this time.

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1 Introduction

The acclaim of wind power as a clean and renewable energy resource is widely lauded, and at the same time hotly debated, in many circles. What is not commonly understood are the ramifications, both financial and technical, to the electrical system when one replaces a firm energy supply with a non-dispatchable variable generation resource such as wind.

Natural Resources Canada published information from the Joint Review Panel Report on the Lower Churchill Project as well as an independent assessment performed by Navigant Consulting. Participants at the Joint Review Panel suggested that an 800 MW wind plant on the Avalon Peninsula should be considered as an alternative for supplying domestic demand. NRCan noted that for wind penetration levels up to 10% by energy in 2035 (about 300 MW) there is typically no need for changes to the electrical system, and this should be manageable for Newfoundland. NRCan also noted that an 800 MW project could equate to about 25% of the Island's power, which is a very high penetration level for an islanded system compared to other jurisdictions in the world. Wind proponents have promoted a sole wind power solution as replacement for the 824 MW Muskrat Falls Generating Station and Labrador-Island HVdc Link, and ultimately the 465 MW Holyrood Thermal Generating Station as well [1].

This review seeks to answer the question, "Can sufficient wind generation be installed on the Island to replace Holyrood Thermal Generating Station and provide a firm supply of electricity to Island customers over the long term?" The Island of Newfoundland is large with significant wind resources available across the Island. The existing ac transmission system has limited power transfer capability to the Avalon Peninsula where a majority of the island load resides. This fact may necessitate upgrades to accommodate any large amount of generation installed on the western side of the Island. Several relevant technical studies have been undertaken or commissioned by Nalcor to identify and evaluate the various resource supply options and technical constraints that exist on the island.

Hatch Engineering has completed a study entitled "Wind Integration Study – Isolated Island", dated August 7, 2012 [2]. This Hatch study recommends the amount of wind generation that can be economically and reliably integrated into the Isolated Island system from 2012-2067. Nalcor has provided a separate report on the effect of adding wind power and its impacts on the frequency stability and voltage regulation of the isolated island power system [3]. The report assesses the technical limits of the system to accept this variable generation resource based on minimizing the required system upgrades.

The purpose of this MHI study is to provide a learned opinion and commentary on the reasonableness of the reports completed by Nalcor on the subject of wind applications to the Isolated Island scenario.

MHI study goals:

1. Complete a due diligence review of the Hatch study and Nalcor's information provided to determine if the study goals set out for Hatch study have been met.
2. Utilizing the Hatch Study and other literature as appropriate, complete a high level screening study that addresses the following questions: "In an isolated island scenario, can sufficient wind be developed to replace the Holyrood Thermal Generating Station and meet future demand? Is this a technically feasible and economic alternative to Muskrat Falls?"

2 Review of Existing Work

2.1 Hatch 2012 Wind Integration Study

Hatch was commissioned by Nalcor to perform an assessment on the amount of additional non-dispatchable wind generation that may be added to the Isolated Island of Newfoundland electrical system [2]. The study considered the operational effects on the existing and future planned isolated-island hydroelectric and thermal generating plants. Several key technical impacts to the grid were identified and studied:

- Hydroelectric dam reservoirs may require a significant amount of water spill during periods of high wind generation and low load.
- Voltage and frequency stability of the power system is reduced as the amount of wind penetration increases, which reduces power system reliability.
- Wind energy may be used to reduce the amount of thermal generation required at Holyrood, up to a point where the minimum thermal generation limit is reached. If readiness must be maintained, the Holyrood thermal generation plants must operate at a level above their minimum limit.

These technical issues place limitations and constraints on the amount of wind that may be accepted into the grid at any point in time and these technical limitations are studied in this report. From a high-level perspective, the maximum acceptable level of wind penetration for the year 2035 was 425 MW representing an energy penetration level of 14%. A more in depth and detailed technical analysis would be required before approaching this level of penetration.

The report also presented information from published literature on wind penetration levels and issues in other jurisdictions such as:

- Europe - interconnected
- USA - interconnected
- Canada - interconnected
- New Zealand - isolated island
- Hawaii - isolated island

The survey of practices and experiences from these other jurisdictions suggest a limit of 10% wind penetration based on capacity in an isolated scenario for the Island of Newfoundland.

The conclusion of the report recommends no greater than 10% wind penetration on an energy basis be attempted for the isolated island of Newfoundland based on a combination of; the technical study results, certain system operating assumptions, and the experience gained from other jurisdictions operating with high wind penetration levels.

2.1.1 Study Methodology

The wind integration study performed by Hatch primarily focuses on how wind generation affects water management of existing hydroelectric power plants on the island. As wind penetration levels increase, there is increased risk of water spill for these hydro plants. The amount of this spilled water under different scenarios was studied and presented. Hatch used the software tool Vista DSS™[1] in order to determine how the addition of wind generation could affect hydroelectric operations.

At present, the hydroelectric power plants are operated in such a way as to minimize spill and ensure compliance to their operational licenses. Nalcor states that sufficient water must be held in its reservoirs to ensure firm energy demands can be met for a repeat of Newfoundland's driest years [4]. This translates into holding water in storage for future needs up to 3 ½ years away. In contrast, holding too much water increases the likelihood of the need to spill excess water from the reservoir. Spilling represents a loss of opportunity to generate renewable energy from an existing asset.

The impact of wind on two of the largest storage reservoirs, Meelpaeg and Long Pond has been quantified. The addition of 200 MW of new wind capacity through 2020, 2025 and 2035 increase the average levels for these two reservoirs by 2 meters in 2020, 1.5 m in 2025, and 1.25 meters in 2035.

2.1.2 Review of Wind Penetration in Other Jurisdictions

Hatch makes reference to other jurisdictions in terms of wind penetration levels that have been achieved or are planned (up to 26% on an energy basis in one case). However, it is not mentioned what issues have been experienced and what changes may have been made to achieve the wind penetration levels noted.

The isolated island wind scenarios in New Zealand and Hawaii were discussed in terms of their future plans, but do not represent the current state. Both islands have ambitious wind

[1] Vista DSS is a registered trade-mark of Hatch Ltd.

development plans. In addition, these jurisdictions are willing to accept additional wind integration costs and associated system upgrades in order to achieve these high penetration targets. As an example of system upgrades, these may include additional synchronous condensers and transmission line upgrades.

2.1.3 Study Conclusions

The Hatch report concludes, "A penetration rate of 10% on an energy basis in 2035 is the maximum recommended for the Island of Newfoundland system due to the uncertainty of the technical and economic impacts at the higher penetration rates which are yet to be tested under isolated system circumstances." The report also notes that up to a 10% wind penetration level on an energy basis is achievable without the need to:

- Add a sophisticated wind forecasting system
- Retrofit existing generators to allow lower minimum outputs, fast starts, and higher ramp rates
- Increase regulation reserves
- Implement aggressive load management systems

In order to achieve penetration levels between 10% and 30% on an energy basis, studies such as the Oahu Wind Integration Study [5] indicate that the above system modifications are required at a minimum.

MHI's research has indicated that isolated system wind penetration levels beyond 25-30% on an energy basis have not been thoroughly studied to date. Significant storage, backup generation and demand response systems would be required to balance wind and load variability. These high penetration levels have only been exhibited in small isolated wind-diesel-solar-battery type installations but not at a utility scale.

2.1.4 MHI Assessment

MHI notes that the study methodology selected a 5-day time step for the system simulation in *Vista DSS™*. This resolution is sufficient for a high-level study of water levels in large reservoirs, but does not fully take into account the moment-to-moment wind supply and load variations that would become a significant challenge to system operation at high levels of wind penetration. For low levels of wind penetration (less than 5%), it is the opinion of this consultant that this level of granularity should be sufficient. An hourly time step is recommended for penetration levels between 5% and 10%, along with more detailed technical integration and feasibility studies that may uncover the need for modifications to other generators, equipment and operating procedures to support the additional wind.

The usage of the term *economic feasibility* in the Hatch report refers to accommodating wind at a reasonable cost, and is not to be interpreted as the cost of wind power being lower than the cost of other sources.

MHI concludes the Hatch report was developed following good utility practices.

2.2 Nalcor 2012 Technical Wind Integration Study

The Nalcor Report titled "Wind Integration Study – Isolated Island: Technical Study of Voltage Regulation and System Stability" evaluated the allowable wind penetration levels for the Isolated Island of Newfoundland [3]. Base cases in the years 2020 and 2035 were considered under both peak and light load conditions. The analysis in this report focused on the voltage regulation and transient stability requirements of the electrical power system.

A maximum of 500 MW of wind power was deemed reliable under extreme light load conditions over the study years. In year 2020, the light summer and peak winter loads were estimated as 490 MW and 1593 MW respectively, while in 2035 these are forecasted to reach 557 MW for the light load case and 1798 MW under peak load. The result is a very large proportion of wind in relation to the total required generation during the night. This assumes the full wind energy would be accepted into the grid and that hydro and thermal generators would be turned off. Aside from the stability issues, there would be other operational issues to contend with.

It was recommended in the Nalcor report to:

- Limit the dispatch of net wind generation to below 225 MW for the year 2020 and 300 MW for the year 2035 during the extreme light load conditions. The reason for this is to ensure system stability.
- Evaluate historical wind data for potential wind sites across the island.
- Perform further analysis to simulate the effect of wind power variability on overall system frequency control. This involves a more detailed analysis and was not included in the scope of this study.
- Consider the benefits of wind farm development in a geographically dispersed manner. This strategy seeks to reduce the severity of wind power cut-outs due to high wind speeds, which may lead to subsequent system load-shedding.
- Perform a detailed investigation into alternate solutions for avoiding under frequency load shedding. This may occur upon the sudden a loss of multiple wind farms due to adverse operating conditions. Potential solutions could include high-speed flywheel energy storage systems and/or the dispatch of fast response generation such as gas turbines.

MHI's research has determined that the current state of high-speed flywheel energy storage, while promising for the future, is not at a sufficient level of technological maturity to be considered in the current analysis.

2.2.1 Study Methodology

The Nalcor 2012 study employed Doubly Fed Induction Generators (DFIG)[2] or a Type 3 wind generator) each with a rated power of three MW. The main advantage of this choice of wind turbine is that it allows the wind turbine to control the power and voltage at its terminals much like a regular generator. The modeling of wind machines followed good utility practices. Each wind farm is rated at a capacity of 27 MW and is interconnected at either the 66 kV or 138 kV levels. For expansion modeling purposes, the study assumed that a maximum of three 27 MW wind plants[3] were installed at any one location. The wind farm developments covered a geographically diversified area across Newfoundland.

In order to assess the system stability as wind generation is expanded, electrical fault studies[4] were undertaken, which included various disturbances including three-phase faults at various points on the ac transmission system. A three-phase fault is an extreme electrical event where all three conductors are shorted together. Additional credible disturbances including load rejection, tripping of the largest generator unit, sudden load increase, and ac line faults followed by unsuccessful reclose were included in the stability study. A stable electrical system must survive all of these events or contingencies.

The adopted voltage criteria applied by Nalcor for normal and post-contingency operations follows good utility practices. The electrical system should maintain stability after transmission line faults and a generation loss event without the aid of under-frequency load shedding.

2.2.2 Study Conclusions

The Nalcor 2012 study concluded that there were no voltage violations observed in the load flow studies for the loading conditions considered in both the 2020 and 2035 cases.

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[2] A DFIG is a type of electric generator that has windings on both stationary (stator) and rotating parts (rotor) of the machine. Both these windings transfer power between the shaft and electrical system and are primarily used in applications that require varying the speed of the rotor.
[3] A 27 MW wind farm is typically derated to 25 MW due to turbine proximity wind loss effects, known in the industry as array losses.
[4] A fault study simulates adverse electrical events such as a short circuit to determine power system responses to the event.

However, stability violations were evident in the study results during high wind power outputs and light load conditions. This is consistent with theoretical expectations as very little inertia[5] or spinning mass is present in the power system under these conditions. Spinning mass is directly related to the number and size of generators connected. Fewer conventional generators are required under light load conditions, and therefore the total system inertia would be reduced.

Transient stability analysis was conducted for the sudden loss of multiple wind farms geographically close to one another because of a high wind speed cut-out event. The loss of two 25 MW wind farms would result in load shedding for the 2020 Light Load base case with 225 MW of wind penetration. The impacts on system stability due to the addition of additional synchronous condensers were also evaluated. The addition of system inertia in the form of two 300 MVAr high inertia synchronous condensers eliminates load shedding for a loss of two wind farms.

2.2.3 MHI Assessment

It is suggested by MHI that the stability impact from a sudden load increase or wind farm loss of 15 MW be evaluated with the consideration for additional system inertia in a future detailed study. The additional system inertia could be provided by using existing idle generators in synchronous condenser mode or by considering the addition of more synchronous condensers.

Given that the variability of wind was not considered in this study and Nalcor currently has not assessed the impact on spinning reserve for this level of wind generation, the considered wind penetration levels may be at the higher end of the acceptable range. In general, wind forecasting is an evolving technology, and the accuracy of predicting wind power output varies greatly depending on the period considered. It has been observed that variability of power output up to the full rating of the wind farm can occur within an hour. Adding synchronous condensers may help compensate for a lack of power system inertia, but a detailed study would be necessary to evaluate this effect further.

[5]Inertia in an electrical power system is related to the spinning mass of all the generators that are directly connected to the power grid. Inertia on an electrical power system helps stabilize frequency for any instantaneous imbalance between load and generation. I.e. in the case of a large disturbance (typically the loss of a large generator) the frequency change is smaller for a system with high inertia compared to a system with low inertia, and hence a high inertia system is more stable.

In summary, the Nalcor Wind Integration study conforms to good utility practice. The wind penetration levels studied were high compared to those of many other jurisdictions, but are within a reasonable range for evaluation. The recommendation of a geographically dispersed wind development plan is consistent with wind industry evaluations showing that some wind farms may continue producing energy when others have stopped due to adverse wind conditions.

2.3 Review of Wind Experience in Ireland

Leading edge work and experience of installing large amounts of wind in Islanded systems has occurred in Ireland. The current wind power penetration is 22.6% based on capacity and 17% based on energy as of August 2012. It should be noted that this level of wind development is partly assisted by the Moyle DC Interconnector, which links the electricity grids of Northern Ireland and Scotland and the East West Interconnector (EWIC) links the electricity grids of Ireland and Great Britain.

Detailed wind development studies in Ireland included investigating the system frequency response to disturbances, reactive power and voltage control studies, transient stability analysis and electrical fault analysis, with various wind penetrations up to 100%. These detailed studies show a safe (stable system operation after one contingency) with a wind penetration of 37 % by energy. This result is one of the reasons why the Irish grid has a 2020 target to attain 40% of its electricity from renewables and much of that (up to 37%) will be wind power. The 40% wind penetration by energy is thought possible in Ireland because a plan has been developed to implement the correct mitigation techniques for inertia, fault, and stability issues. These mitigation strategies include increasing system inertia, adding more reserves from conventional plants, adding reactive power sources [6], and providing system operators with a wind security assessment tool to aid operators in assessing the impact of wind on system transient and voltage stability [7].

2.4 Other Studies

In prior work [6], MHI assessed Nalcor's wind plan and concluded that the assumption of a 40% capacity factor for new wind plants was reasonable. This was based on the performance of two existing wind plants (Fermeuse – 35.7% capacity factor, St. Lawrence – 44.3% capacity factor) and submissions to requests for proposals received in 2005/06 (capacity factors ranged between 35% and 43%).

Nalcor performed an assessment in 2004 and recommended an upper limit of 80 MW for non-dispatchable generation in Newfoundland, based on displaced fuel costs. At that time, marginal fuel costs were less than the cost of installing wind, and thus there was no economic benefit in going beyond the 80 MW limit. The 2012 Hatch study has updated these results to reflect the 2012 fuel prices.

3 Wind as a Replacement for Holyrood Thermal Generating Station

3.1 Introduction

This study proposes and evaluates a set of scenarios where a large amount of Holyrood thermal generation energy, and the associated fuel costs, could be displaced using wind farms for the electrically Isolated Island of Newfoundland. The existing Isolated Island option includes the development of the major remaining on-island hydro resources, up to 10% penetration on an energy basis of wind power, and a large number of thermal generating plants.

Holyrood Thermal Generating Station was placed in service in 1970, and burns No. 6 fuel oil in its three units to generate up to 465 MW of electricity. When system demand is low or there are favourable water reservoir levels, the Holyrood Thermal Generating station is dispatched in such a way to minimize fuel usage and impact to the environment. As a result, the actual electricity production is often much less than 465 MW. However, in cases where demand is high, and other plants are out of service or the hydro system is affected by drought, this station is plays a critical role in maintaining electrical service to the Island.

In the Isolated Island option, Holyrood Thermal Generating Station would operate until 2035 and be decommissioned in 2036. Replacement of thermal generators would be built and put into service as each of the three Holyrood generators reaches end of life. The plan continues in this way until the year 2067, an arbitrary point defined by financial depreciation schedules in order to compare various alternatives. The question of replacing Holyrood Thermal Generating Station with wind generation is considered in this study to include the replacement of Holyrood Thermal Generating Station and the subsequent Combined Cycle Combustion Turbine (CCCT) generators up to the year 2067. In this way, the economic evaluations may be compared on an equal footing.

The scenarios under study in this report are:

- The Isolated Island option (as a basis for comparison)
- Isolated Island with large scale wind and peaking thermal plants as a replacement for Holyrood Thermal Generating Station
- Isolated Island with large scale wind and batteries as a replacement for Holyrood Thermal Generating Station

The two new large scale wind scenarios have been developed with consideration given to several of the technical integration issues identified in prior study work by Nalcor. The amount and type of equipment to be installed over the study horizon is identified, capital and operational costs are estimated and a Cumulative Present Worth (CPW) calculation is performed using estimates that provide a screening level economic analysis of these projects.

Since this is a high-level desktop study, the results and conclusions should only influence the decision whether or not to spend more time and effort in improving the level of certainty in these estimates. The amount of work required to bring these theorized wind scenarios to the same technical maturity as the existing Decision Gate 3 Isolated and Interconnected options is substantial, and the estimated cost of the scenarios theorized here are more likely to increase than decrease as requirements are identified.

3.2 Wind on the Island of Newfoundland

The Canadian Wind Energy Atlas is a free online resource showing the potential wind energy available throughout Canada [7]. According to the information at this site, MHI considers the wind potential in Newfoundland among the best in the country. A wind energy map showing the best areas for wind farms on the Island is shown in Figure 1. The majority of the electrical load on the Island of Newfoundland is on the Avalon Peninsula, especially in the area surrounding St John’s, and so the transmission infrastructure would need to support the delivery of wind energy from the various sites on the island to the St. John’s area. As noted in the Nalcor 2012 report, there is an advantage to spreading the wind generation plants geographically across the Island to mitigate the variability of wind.

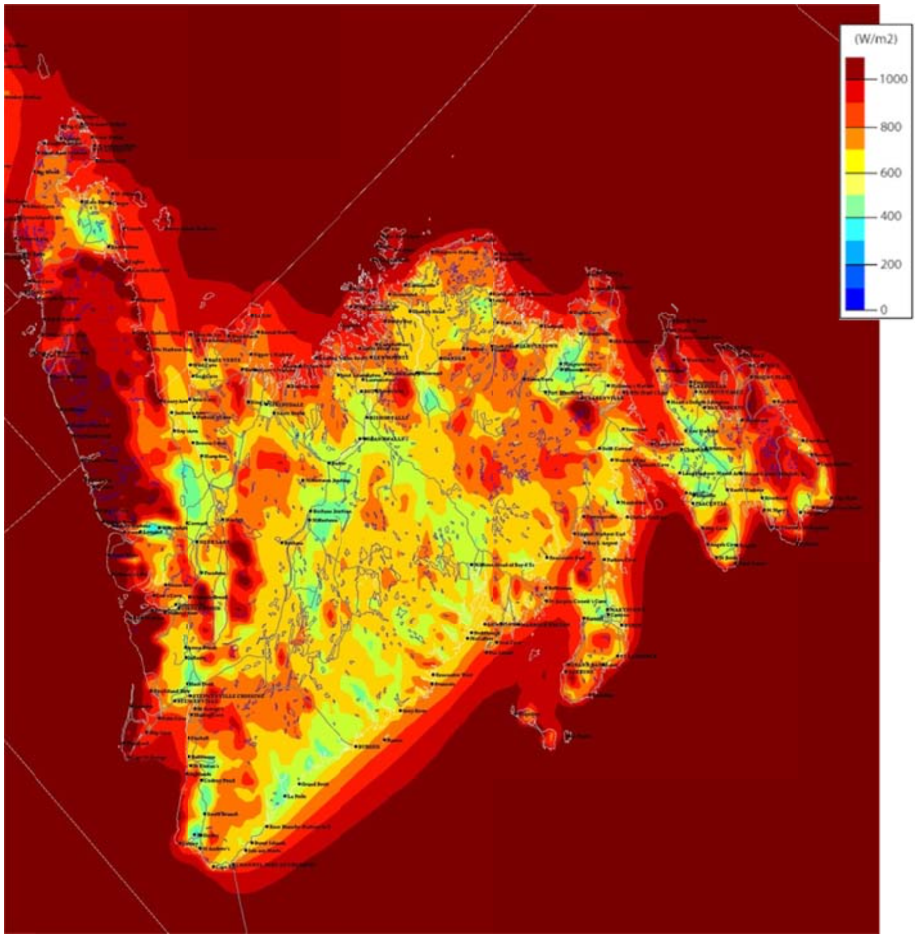

Figure 1: Annual Mean Wind Energy Map for the Island of Newfoundland, at 80 meter height [7]

In order to replace Holyrood generating station, and its associated replacement thermal generation planned to up to 2067, MHI has determined that 1100 MW of wind power would be required. This amount of wind power would produce up to 3.1 TWh of energy at a 90% probability of occurrence (P90) in any given year, assuming a 40% average annual capacity factor for all wind turbines. This is the amount of energy that Holyrood Thermal Generating Station is required to produce in a worst-case drought year. The P90 standard is used here since many financial institutions have adopted this as the minimum level of certainty for wind energy production to authorize loans to wind farm projects [8].

Two very promising wind resource areas for large-scale wind development are identified in Figure 2. These areas are separated by a straight-line distance of approximately 320 km, have close proximity to major transmission line infrastructure and experience a significant amount of wind throughout the year. In a more detailed study, significant wind data collection would be commissioned at multiple sites to improve the understanding of the wind and local weather in the identified areas. The 1100 MW may be split into several more farms so there is diversification to mitigate the weather fronts impact at each farm. More detailed studies must be performed before considering such a large scale wind development. These studies were outside the scope of work for the present conceptual exercise.

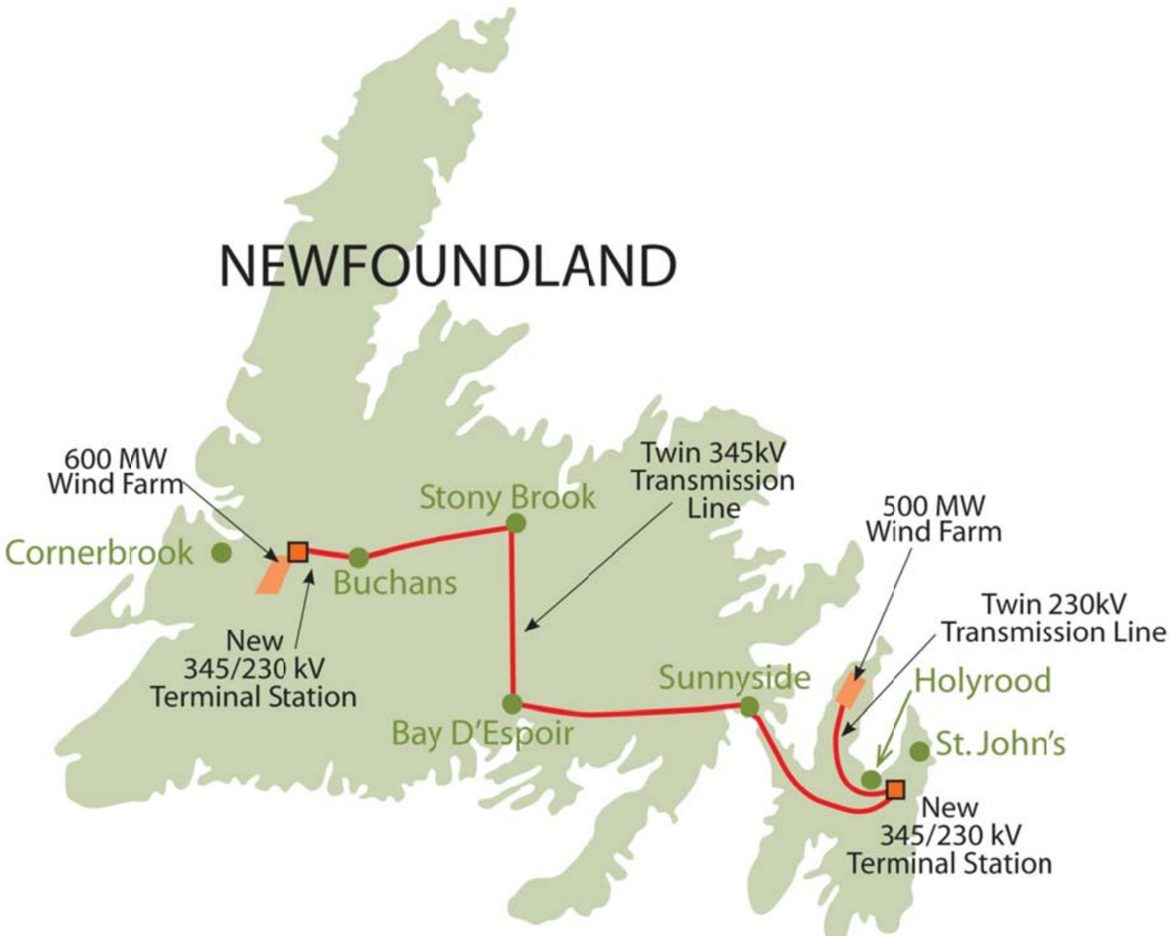

Figure 2: Large Scale Wind Development - Potential Locations

3.3 Large Scale Wind Development Scenarios

3.3.1 Wind Farm and Transmission Requirements

Using the wind energy maps as a guideline, the 1100 MW of wind is placed into two locations; 500 MW in the Avalon location with another 600 MW at the West location near Corner Brook as shown in Figure 2. The 500 MW farm would cover an area approximately 16 by 10 km, whereas the 600 MW farm would be 24 by 8 km. The construction of these wind farms is assumed to be in blocks of 100 MW, as this size is deemed reasonable to allow a trip-out to be handled by the rest of the power system once suitable system upgrades are put in place. The sequence for building the full 1100 MW of wind is shown in Table 2.

Table 2: Build Schedule for 1100 MW of Wind

Year	Item	Capital Cost (millions in 2012$)	New Installed Capacity
2014	100 MW Wind Installed at Both Locations	$489.0	200 MW
2015	100 MW Additional Wind Installed at Both Locations	$489.0	400 MW
2016	100 MW Additional Wind Installed at Both Locations	$489.0	600 MW
2017	100 MW Additional Wind Installed at Both Locations	$489.0	800 MW
2018	100 MW Additional Wind Installed at Both Locations	$489.0	1000 MW
2019	100 MW Additional Wind at West Location	$244.5	1100 MW

It is normally considered that the wind farms would have a useful life of 20 years, after which refurbishment is necessary. This new installed wind capacity is in addition to the wind developments already included in the Isolated Island option. Significant transmission infrastructure development would also be required to support this wind development. The theorized scheme is illustrated in Figure 2 and the build schedule is detailed in Table 3.

Table 3: Transmission System Build Schedule for 1100 MW Wind Development

Year	Item	Capital Cost (Millions in 2012$)
2014	New Terminal Station for Avalon Wind Farm	$10.0
	New Terminal Station for West Wind Farm	$10.0
	8 x 230 kV Circuit Breakers	$20.0
	126 km of 230 kV Transmission Line	$75.6
	440 km of 345 kV Transmission Line	$440
2015	2 x 230 kV Circuit Breakers	$5.0
	30 km of 230 kV Transmission Line	$18
2016	5 x 230 kV Circuit Breakers	$12.5
	126 km of 230 kV Transmission Line	$75.6
	440 km of 345 kV Transmission Line	$440
2017	4 x 230 kV Circuit Breakers	$10.0

	30 km of 230 kV Transmission Line	$18
2018	1 x 230 kV Circuit Breaker	$2.5
	30 km of 230 kV Transmission Line	$18

The western wind farm would be constructed in six steps of 100 MW, with each step adding a 30 km 230 kV transmission line to a new terminal station near Buchans. A new double circuit 345 kV transmission line would be required to transmit the additional 600 MW of wind power from Buchans Terminal Station to a new terminal station near Holyrood Thermal Generating Station referred to here as Soldier's Pond.

The Avalon wind farm, similarly staged, would require a new 230 kV terminal station, where up to 500 MW of wind power is collected and transmitted via two 230 kV transmission lines (126 km) running south to Soldier's Pond. Delivering power to the ac transmission system at this location is assumed similar to an equivalent injection of power from Holyrood Thermal Generating Station.

3.3.2 Synchronous Condenser Requirements

As mentioned in Section 2 – Review of Existing Work, large-scale wind development may be limited by the frequency stability of the power system upon the occurrence of a disturbance such as a short circuit or the trip-out of any single 100 MW wind farm. In order to get around this limitation, it is recommended by MHI that a number of synchronous condensers could be used to increase the inertia of the power system.

The reason for this is that when a generator or load is suddenly disconnected from the system, other generators must add or reduce their power output to prevent under-frequency load-shedding, over-frequency trip outs, or in the worst case, a blackout event. The response time of other generators in the system is dependent on the type of generator (such as Hydro, Steam Thermal, or Combustion Turbine) each having their own time related response mechanisms.

Starting at the instant following a generator trip-off, and continuing until the remaining generation systems increase their power output sufficiently, the speed of the remaining generators will be in decline. The result is that the system frequency declines as well. The rate of slowdown and the lowest frequency reached is dependent on several factors, including the size of lost generation, spinning mass in the power system, and response time of the remaining generators. If the frequency declines beyond certain set levels, loads would automatically be turned off by load shedding systems to help balance the load.

This problem is exasperated in a system with high wind penetration because the spinning mass or inertia contributed by wind generators is typically zero or very low. Wind generators can trip out suddenly when the wind is blowing strongly and gusting, and the other generators in the system are running at low power levels or are completely disconnected. This problem would be more pronounced on a summer night when the winds are strong, loads are low, and other generation is reduced in order to maximize the use of the wind energy.

The amount of additional inertia required has been determined for the purposes of this exercise by using criteria from other studies as a reference [9]. A more comprehensive method of determining this requirement is to perform detailed computer simulations of the power system under the worst-case conditions, as in the Nalcor voltage regulation and stability study in [3]. This approximation has been used to arrive at a qualitative estimate of 1100 MVAr for study purposes. Estimated time phased addition of this synchronous condenser equipment and costs are given in Table 4.

Table 4: Synchronous Condenser Costs for 11oo MW Wind Development

Year	Item	Capital Cost (Millions in 2012)
2014	Use Holyrood Unit #3 as a Synchronous Condenser	$0.0
2015	Convert Holyrood Unit #1 to Synchronous Condenser	$3.3
2016	Convert Holyrood Unit #2 to Synchronous Condenser	$3.3
2017	Build 300 MVAr Synchronous Condenser	$90.0
2018	Build 200 MVAr Synchronous Condenser	$60.0
2019	Build 150 MVAr Synchronous Condenser	$45.0

Existing thermal generation units at Holyrood GS would be converted to synchronous condensers as wind is added to the system from 2014 to 2016. These units are expected to require a rebuild every 20 years, while the new synchronous condensers starting in 2017-2019 are expected to last through the study horizon to 2067. It has been assumed that 1100 MVAr of synchronous condensers would support the addition of 1100 MW of wind (plus the 279 MW of wind already planned for the Isolated Island option).

3.3.3 Operating Requirements

In many cases, wind farms have been installed at low penetrations on a utility grid, and the wind farm is operated by a private company, not the interconnecting utility itself. Power Purchase Agreements are typically structured where the utility has to “take or pay” for the wind energy available. This results in the utility taking extra steps to accept the wind energy, which may result in the spilling of water at hydro dams and operation of hydro or thermal generation assets in a less than efficient manner.

Due to the massive size and importance of the theorized wind farm relative to the Isolated Island electrical system, this exercise assumes that the utility would own all the additional 1100 MW of wind generation theorized in this plan, or the power purchase agreement is structured with a requirement to allow the spilling of wind. In this way the transmission system operator can operate reliably and the utility may optimize their operations and choose between "spilling the wind" and "spilling the water" based on the prevailing economic and technical considerations.

Wind Integration Costs

Wind Integration is a term used to describe the additional burden placed on the electric utility to manage the integration of wind resources with conventional dispatchable generation such as hydro and thermal. In a utility without wind integration, the generators are dispatched in response to the load from customers. Over time, customer usage usually follows a predictable trend. The electric utility can depend on these trends to some extent in managing water reservoir levels, maintenance schedules, and the amount of spinning reserve required.

As wind is added to the system, a new variable appears in the daily management of matching generation to load requirements. At low levels, this is indistinguishable from normal customer load variation, and the wind integration cost is nil. As wind penetration levels increase, the variability of wind creates more variability in the load requirements that dispatchable generation sources must meet. As a result, the amount of load-following generation would require adjustment. Load following generation is generally more expensive than base load generation, sometimes because of pure operating costs, and other times because of lost opportunity costs to supply firm loads. Generators must run partially or completely unloaded to carry out the load following function. Furthermore, many base load thermal plants are technically incapable of operating in load following mode, or are inefficient in doing so.

Actual wind integration costs are determined by a utility based on its specific situation. The general trend is that wind integration costs increase with wind penetration. Examples are 0.185 cents/kWh at a 3.5% wind penetration by capacity in 2003 and 0.497 cents/kWh at 15% wind penetration by capacity in 2006 [10]. In the wind scenarios presented in this report, the 1379 MW (1100 MW plus 279 MW) of wind in 2035 would represent 40% wind penetration by capacity, thus MHI has applied 1.0 cent/kWh wind integration cost for the purposes of the CPW analysis.

3.3.4 Selection of Wind Turbine Technology

The theorized 1100 MW wind power plant is assumed to use similar wind turbines as the two existing wind farms at Fermeuse and St. Lawrence; using 3 MW doubly fed induction generators (DFIG). These types of wind machines do not normally provide inertia or contribute to the fault level. For more comparisons on wind machine capabilities with respect to inertia and fault level contribution, see [11].

By using power electronics to manage varying rotor speeds as a result of varying wind, independent of the grid frequency, a DFIG can maintain optimum wind turbine power output for any given wind speed. As a result, they are insensitive to grid frequency and therefore most currently available machines provide no inertia. However, a DFIG with the appropriate control system could be made to supply system inertia, as is the case with the GE Energy WindINERTIA™ Control [12]. This machine utilizes power electronic controls to take some of the mechanical inertia of the rotor for a temporary increase in electrical power output over a short period of time, thus creating the effects of inertia. A recent report [9] recommended that further study and experience be undertaken before implementing large scale virtual inertia type wind turbine farms, and thus this feature is not considered in the analysis for this exercise.

Another concern about implementing a large-scale wind development is the lack of fault current supplied by DFIG wind turbines. Fault currents are used by protective devices in the power system to detect when a circuit should be tripped (opened) to clear the faulted equipment from the system fast enough to prevent cascading trips of healthy circuits. A high fault level (usually over 1000 MVA) is a characteristic of a strong power grid that has the ability to withstand disturbances and minimize fluctuations arising from switching loads, transmission, or generation equipment in or out of service [11]. For most power grids, insufficient fault level concerns tend to be localized. Resolution of low fault level issues can also be achieved by adding synchronous condensers to the problem areas, and so low fault level and low inertia efforts may be best addressed at the wind farm locations [11]. A detailed treatment of these issues is outside the scope of this exercise.

3.3.5 Cold Weather Performance of Wind Turbines

There are two main issues affecting the operation of wind turbines in cold weather.

- Impact of low temperatures on the blade and tower materials
- Ice accretion on the tower and blades

The steel used in turbine towers can become brittle at low temperatures, while composite turbine blades are subjected to mechanical stress due to non-homogeneous shrinkage in the bulk material. At sufficient levels, this can result in micro-fractures and premature failure, which means the turbine may not last its anticipated 20-year design life. Electrical equipment such as generators, yaw drive motors and transformers can also be damaged by low temperatures. At the lower temperatures, the viscosity of the lubricants in the gearbox and the hydraulic fluids in the blade pitch control increase dramatically. Damage to gears in main gearbox or in the pitch drive will occur in the first few seconds of operation where oil or fluid is very thick and cannot freely circulate. In addition, due to an increase in internal friction, the power transfer capacity of the gearbox is reduced when the oil viscosity high.

During ice storms, ice collects on the blades and towers and:

- Interferes with the deployment of speed limiting devices such as tip flaps or movable blade tips
- Increases the load on the blades causing excess gearbox stress
- Changes the balance of the rotor causing increased vibration and thus accelerating micro-fracturing of the blades
- Reduces the energy capture by altering the aerodynamic of the blades
- Ice fragments from the moving blades can be thrown a long distance and is a safety hazard
- The presence of ice on the tower increases the wind loading and causes more micro-fracturing

Present day utility scale wind turbines are designed to operate in temperatures as low as -20 °C, and with a special cold weather package may operate down to -30 °C. This cold weather package usually consists of a heating element in the gearbox and additional heaters and insulation in the nacelle of the wind generator, and typically adds cost of about $30,000 to each unit. When the minimum design temperature for a wind generator is reached, it is shut down automatically to prevent damage to the gearbox, blades, and other critical components of the system. Most utility sized wind generators are designed to withstand temperatures as low as -45 °C in a non-operational state.

The ambient temperature on the Island of Newfoundland typically ranges from -20 °C in the winter to +25 °C in the summer, and so a cold weather package it likely not required. However, the hazards posed by ice storms are significant for wind generators, and these are quite common in Newfoundland. It would be prudent to investigate wind turbines that offer some form of ice mitigation ability. Several of the major wind turbine manufacturers (Vestas and REpower for example) are developing strategies for ice mitigation on wind turbine blades, such as the application of specialty coatings to reduce their susceptibility to ice accretion. However, technologies for melting ice from turbine blades appear to be in the early infancy of development. Vibrating turbine blades are detected by the control system, which automatically shuts the unit down. The unit should not be re-started until the ice has been removed and the turbine system inspected.

3.3.6 Capacity Credit of Wind

The capacity credit given to wind has been a hotly debated topic by wind power advocates for many years. The capacity credit must be judged considering the likelihood of all the wind turbines being completely off, such as in a massive ice storm, high wind event, or in widespread calm conditions. Average capacity credit values for wind can be estimated using sophisticated statistical techniques.

As an example, the current installed wind capacity in Ireland is 2066 MW, which is dispersed across Ireland and Northern Ireland. Through long-term study of this system, the capacity credit has been determined to be 18%, or 375 MW [13]. An important feature of the Irish grid is the presence of HVdc transmission interconnections, which provide additional capacity to Ireland from Great Britain. The isolated Island of Newfoundland has no such interconnection in the wind farm scenario for backup supply.

For the purposes of this exercise and in the absence of a detailed technical capacity credit study, since there is a reasonable probability of all wind power being shut down at the same time, the capacity credit allocated to wind power in Newfoundland is zero. Therefore, the wind generation source must be backed-up by other sources such as backup CTs or energy storage. The main value of wind for the isolated Island of Newfoundland from this exercise would be a reduction in fuel use and emissions at thermal generating plants.

3.3.7 Grid Energy Storage as a Backup for Large Scale Wind Development

There are many forms of grid energy storage available including batteries, pumped hydro, and compressed air. A pumped storage evaluation for Newfoundland requires a detailed understanding of the geography and hydrology, both of which require considerable evaluation and engineering and are out of the scope of this report. Pumped storage requires the construction of a hydroelectric generating station with an associated energy storage reservoir adding a large capital expense to the wind alternatives. Other than pumped hydro (a mature storage technology), batteries show the most promise to be a viable grid scale economic storage option in the near term, and so they will be evaluated here.

Lithium-Ion batteries are considered one of the more mature battery technologies and several grid scale demonstration projects have been installed worldwide as shown in Figure 3 below [14]. A study commissioned in 2010 by the US Electricity Storage Association estimated that worldwide electric grid energy storage systems of all types (batteries and others) could reach an installed capacity of approximately 18 GW by 2020, which is about a 10-fold increase from 2010. A substantial portion of this is expected to be lithium ion batteries as shown in Figure 4 [15]. One recent example (October 2011) is the AES Laurel Mountain project in West Virginia which consists of 61 GE 1.6 MW wind turbine generators capable of a combined power generation of 97.6 MW. A total 32 MW (8 MWh) of storage was added to the wind farm and is made up with lithium-ion batteries in sixteen 40 foot shipping containers as shown in Figure 5 [16]. AES is planning larger battery installations in the future.

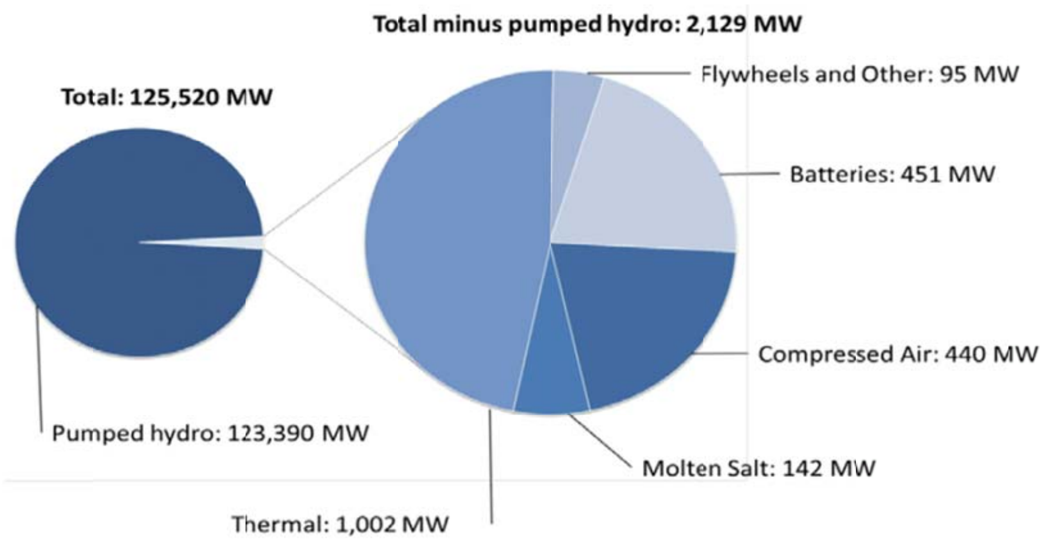

Figure 3: World Wide Grid Energy Storage Estimates [14]

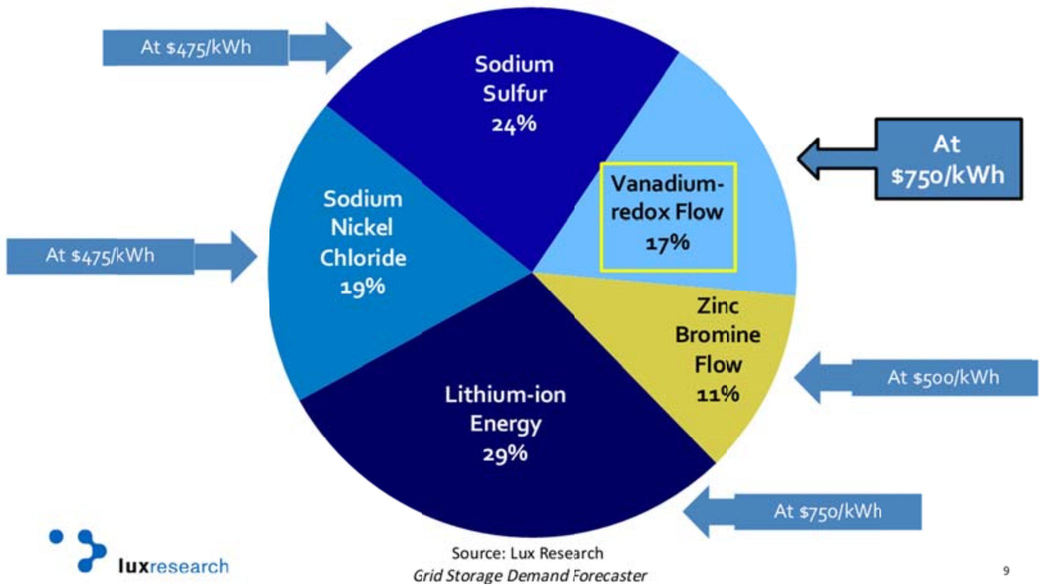

Figure 4: Lithium Ion Battery Cost & Market Share Expected in 2017 [15]

Figure 5: Laurel Mountain 32 MW, 8 MWh Lithium-ion Battery Storage near a 98 MW Wind Farm [16]

3.3.8 Isolated Island Scenario

The Isolated Island scenario forms the reference for the two wind development scenarios. Power plant replacements are identified from the most recent Decision Gate 3 documentation.

The amount of generation capacity is designed to increase over time, such that the combination of Hydro and Thermal plants can meet the forecasted load requirements in every year to 2067. This is represented in Figure 6. Note that the wind does not appear in the capacity graph, since the utility must meet peak load requirements even when the wind is not blowing. The Isolated Island scenario is largely a thermal development plan with new CTs and CCCTs added as load grows over the study horizon.

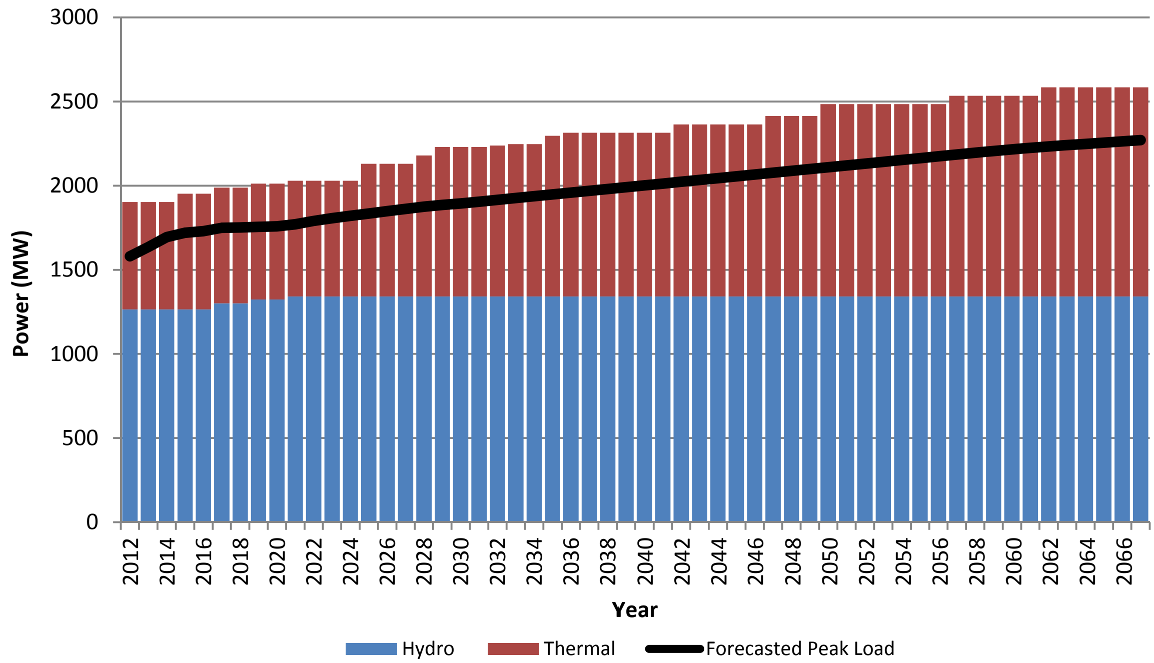

Figure 6: Isolated Island Scenario – Generation Capacity Chart – 2012 to 2067

The amount of installed wind capacity in the Isolated Island scenario is shown increasing from 54 MW in 2012 to a maximum of 279 MW in 2035. This wind development plan results in about 10% wind penetration by energy. The firm capacity reserve is calculated as the percent margin of firm installed generation capacity above the peak load forecast and is maintained at around 15% in most years.

3.3.9 Combustion Turbines as a Backup for Large Scale Wind Development

The case of considering simple cycle combustion turbines (SCCTs or CTs) to back the 1100 MW of wind power when all the wind is down can be easily determined. The shortfall in capacity that must be met by backup thermal plants is determined by the difference between the winter peak forecast and the system installed firm capacity in any given year. MHI recommends that a safety margin of 14% be added to this difference for the Isolated Island of Newfoundland.

In this scenario, the reference case is modified in the following ways:

- Holyrood 1, 2, and 3 are decommissioned in 2017, 2018, and 2019 as wind is developed
- Three 170 MW CCCTs are removed in 2032, 2033, and 2036 including their replacements in 2062, 2063, and 2066.
- Two 100 MW wind farms are added in 2014, 2015, 2016, 2017, and 2018 and replaced every 20 years thereafter
- The final 100 MW wind farm is added in 2019 and replaced every 20 years thereafter
- Additional backup thermal 50 MW Combustion Turbines are installed in 2014, 2015, 2016, and 2023. 100 MW is installed in 2017 and 2018, while 150 MW is installed in 2019. This development sequence is designed to meet a 14% capacity margin throughout the study period

The capacity graph for this scenario is given in Figure 7. A noticeable transition is seen occurring in the years 2017-2019 when Holyrood is decommissioned and converted to synchronous condenser operation, and the new wind capacity is being installed. At the same time, backup thermal generation is being installed to meet the capacity reserve margin of 14%. As load grows beyond 2020 and after the 1100 MW of wind is installed to meet the Holyrood Thermal Generator replacement requirements, additional thermal plants are added to the system to meet both energy and capacity needs. To provide backup for the wind, Combustion Turbines (CTs) are more appropriate to this type of application since they have lower capital cost than Combined Cycle Combustion Turbines (CCCTs), and are more suited to operation as a peaking, or load-following plant. Although the CT energy cost is high, these units are not used as often in this scenario since almost 2/3 or more of the energy would be supplied by the wind generation. The details of the backup generation are described in Section 3.3.9.1 and the cost of backup generation is calculated in the Section 3.4 Cumulative Present Worth (CPW) Analysis of Scenarios.

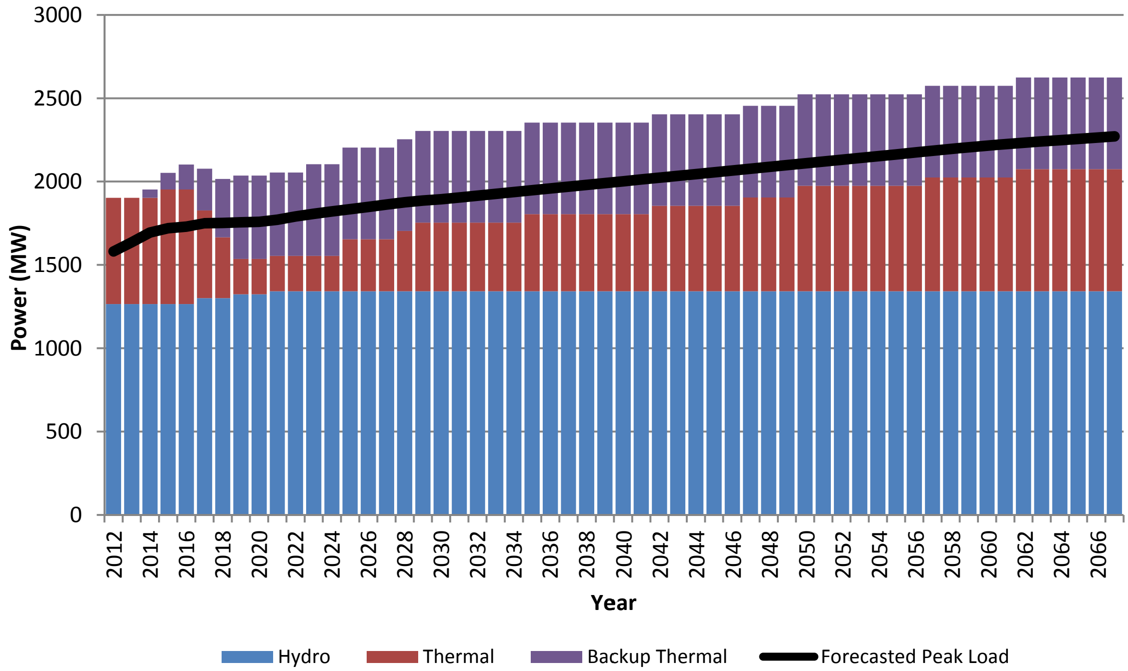

Figure 7: Wind with Thermal Backup Scenario – Generation Capacity Chart – 2012 to 2067

The total amount of installed wind capacity in this scenario increases sharply from 54 MW in 2012 to 1379 MW in 2035. This achieves about 40% wind penetration on a capacity basis in 2035. The firm capacity reserve margin is maintained above 14% in this scenario.

3.3.9.1 Determination of Backup CT Energy Requirements

In this exercise, 1100 MW of wind is used to replace the energy that was produced at the Holyrood Thermal Generating Station. Wind is a variable and non-dispatchable source of energy. In order to support the load reliably, backup CTs are required to deliver the energy and capacity shortfall when there is a shortage of wind energy production and insufficient hydroelectric generation. This occurs when the wind generation falls below 511.5 MW total at the two wind farm locations. The 511.5 MW wind generation level is based on delivering 465 MW of wind power to the Holyrood area considering the additional system transmission and wind farm array losses (10%). Note that since the back-up CTs would likely be installed near points of load and not at the wind farm locations, the amount of back-up CTs required is only 465 MW as no additional transmission losses would be incurred. The backup CT fuel used during these times is calculated such that the additional fuel cost may be included in the CPW analysis. For the MHI assessment, a Vestas V90 3 MW turbine with a 100 m hub height was assumed for the 1100 MW wind farms. These turbines have a low speed cut in at 3.5 m/s and a high speed cut out at 25 m/s. In order to determine the amount of time during the year that the wind output drops below 511.5 MW, the wind probability occurrence method was utilized, which is explained below.

The average annual wind speed for a given location does not by itself indicate the amount of energy a wind turbine could produce at its location, because as the speed of the wind changes the power output varies in a cubic relationship (third power) to the wind speed. Therefore, one needs to know how often different wind speeds occur throughout the year to determine annual energy produced. Measured wind speed data at any particular location is usually plotted on a graph of the frequency of occurrence (probability) of the wind speed versus the wind speed itself. Please see Figure 8 for a typical wind frequency plot. Once obtained, a probability distribution equation is "fit" to match the wind frequency plot so that a probability of occurrence of any given wind speed can be determined. This is because the total area under the probability curve represents 100% probability or all possible wind speeds. Therefore, for any range of wind speeds the probability of occurrence, or the percentage of time that wind speed is within this range, is the area under that portion of the curve. Different locations have different wind speed distributions, and thus different probability curves.

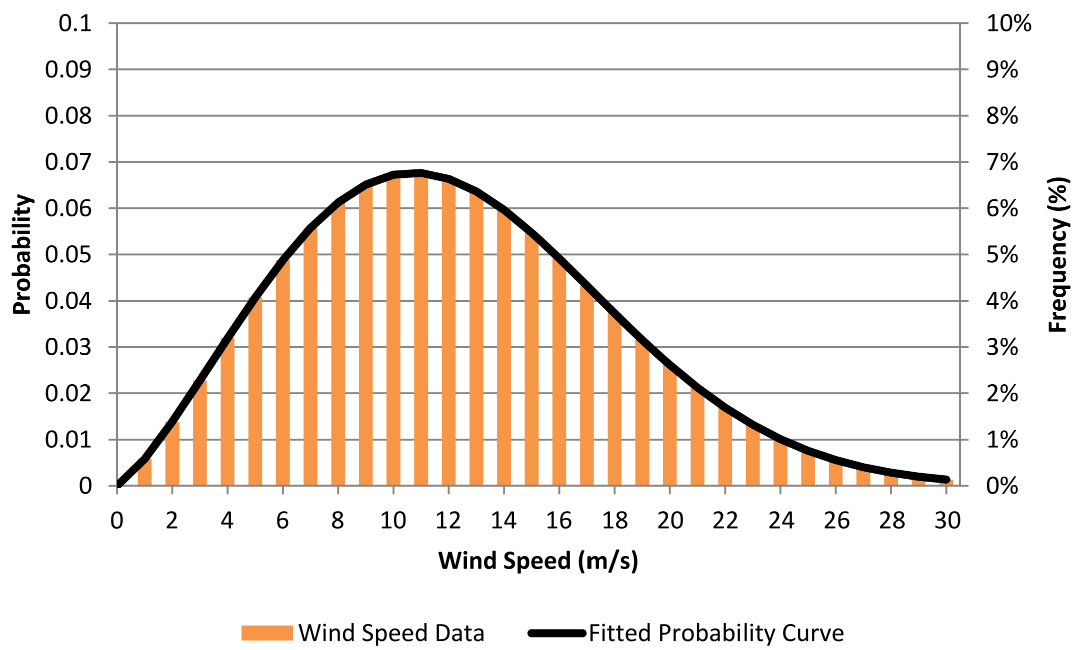

Figure 8: Probability of Wind Speed Plot

These wind probability plots are available at any location in Canada from the Environment Canada website [7]. The probability of occurrence wind plot for the Newfoundland Wind Farm locations is represented in Figure 9**Error! Reference source not found.**. This plot is divided into four areas (1, 2a, 2b & 3), which correspond to four important wind speed ranges.

Area 1 represents the percentage of time the wind turbines are off because the wind speed is too low to start the wind turbine. Area 2a represents the amount of time the wind output is between 511.5 MW and the cut in power. Area 2b represents the amount of time the wind output is between 511.5 MW and 1100 MW. Area 3 represents the amount of time the wind power is off due to high speed cut out. The wind speed at which the two wind farms will produce 511.5 MW of power is determined by considering the individual wind turbine power curve shown in Figure 10.

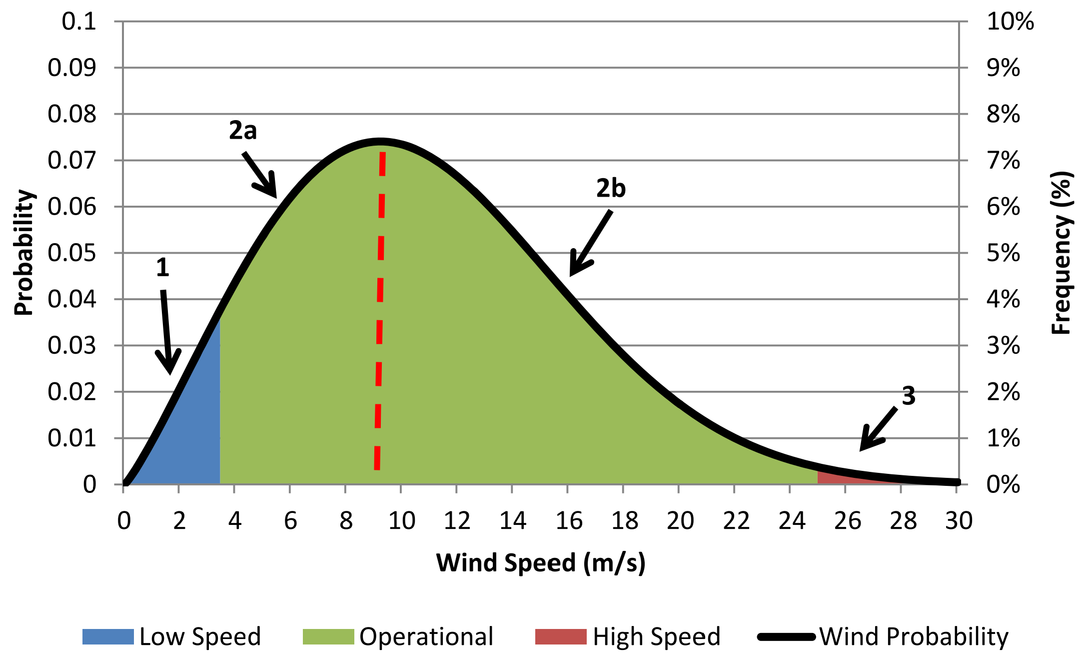

Figure 9: Annual Wind Probability plot for the Avalon wind farm location
Area 1 = 6.2%, Area 2a = 34.3%, Area 2b = 58.6%, Area 3 = 0.9%

According to Figure 9 the wind farm would produce less than 465 MW for 34.3% of the time, and back-up CTs are required to make up the difference. The exact output from back-up CTs at various wind speeds is calculated by dividing the area under the wind probability curve into narrow speed bands and then referring to the turbine power curve to determine the power output and thus the back-up CT power required as follows:

$$465 - 0.9 \times P_W = P_{CT}$$

Where:

P_W	=	instantaneous wind power	[MW]
P_{CT}	=	required power from backup CTs	[MW]
0.9	=	factor to account for losses on wind power	
465	=	total power requirement at Holyrood	[MW]

For 58.6% of the time (area 2b) the wind output is between 511.5 MW and 1100 MW, such that no back-up CTs are required. For areas 1 and 3, the wind turbine is not operational, and so the backup CTs must produce the full 465MW. The area of each narrow band in Figure 9 gives the percentage of time that the calculated back-up CT power would be required. By

multiplying the calculated backup CT power by the respective probability at each wind speed and summing the results, the average CT power required over the course of a year can be calculated, and thus the annual CT energy required.

The above scenario provides 465 MW of capacity (wind plus back-up CTs) 100% of the time (100% operation factor). The operation factor of Holyrood Thermal Generating Station typically varies from 18% to 51% depending on the year. Thus for the study period of 2012 to 2067, the prior backup CT energy values are scaled by a repeating sequence of annual operation factors that have been experienced at Holyrood Thermal Generating Station in the past [4].

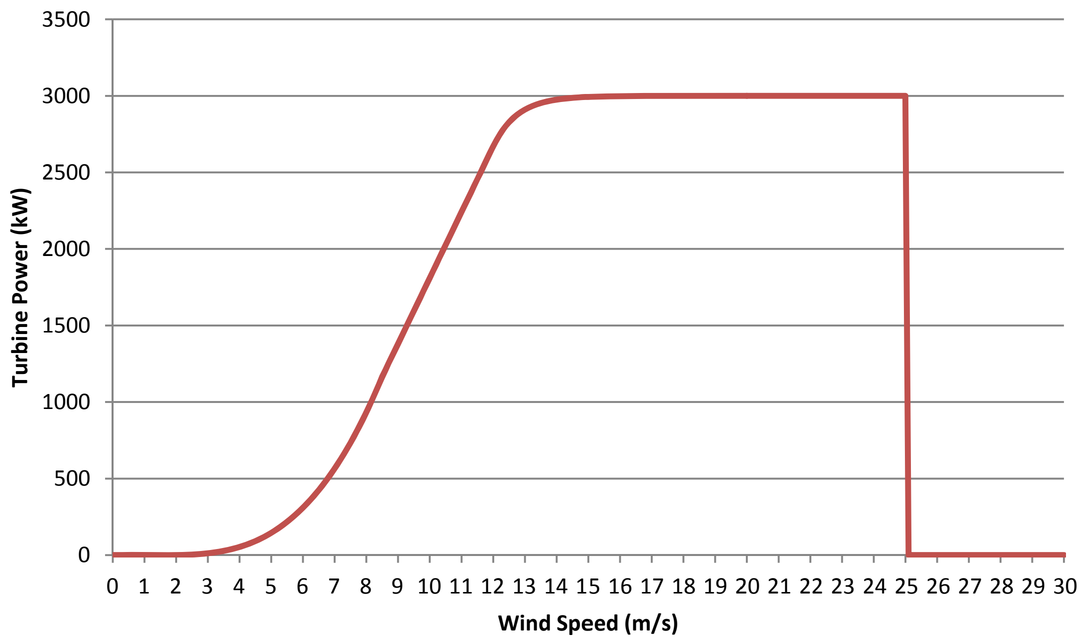

Figure 10: Maximum Turbine Power vs. Wind Speed for Vestas V90 3MW

In order to determine the amount of annual energy required from the wind plus back-up CTs, the historical annual operation factors of Holyrood Thermal Generation Station were utilized. Typical Holyrood Thermal Generating Station operation in any given year is strongly influenced by the amount of water in hydro reservoirs. In 2002 (a low hydro production year), Holyrood Thermal Generating Station produced over 2.3 TWh of electrical energy, while in 2006 only 0.74 TWh were produced. An eleven-year history of Holyrood Thermal Generating Station annual energy output [4] is used to estimate the required back-up CT generation through the years 2012-2067.

Additionally, two practical aspects of CT thermal plant operation must be considered here. The first is a 10-minute duration start-up requirement. In order to reliably produce load following power, a CT must be warmed up, running at rated speed, and synchronized to the grid. To allow for this, two of the eleven 50 MW CTs are assumed to be running while wind energy is being accepted into the grid. This would allow the system operator to respond to a significant loss of wind production inside of 10 minutes without relying on load shedding. The operator would immediately start additional CTs if this spinning capacity starts feeding load.

The second aspect is the minimum loading requirement for the type of CTs used in Newfoundland. Operational experience shows that fouling may occur at power outputs below 20%. Efficiency of thermal plants also decreases as loading is reduced. Therefore, spinning reserve CTs are assumed to be loaded at 20%, or 10 MW each, leaving 40 MW available as spinning capacity. Over the course of any given year, it is expected that the 1100 MW wind plants could replace up to 70% of the energy normally supplied by Holyrood Thermal Generating Station.

3.3.10 Batteries as a Backup for Large Scale Wind Development

In this scenario, the reference case is modified in the following ways:

- Holyrood 1, 2, and 3 are decommissioned in 2017, 2018, and 2019 as new wind is developed
- Three 170 MW CCCTs are removed in 2032, 2033, and 2036 including their re-builds in 2062, 2063, and 2066.
- Three 100 MW, 1.97 GWh batteries are added in 2017, 2018, and 2019 and replaced every 10 years thereafter
- Two 100 MW wind farms are added in 2014, 2015, 2016, 2017, and 2018 and replaced every 20 years thereafter
- The final 100 MW wind farm is added in 2019 and replaced every 20 years thereafter

The capacity graph for this scenario is given in Figure 11. A noticeable transition is seen occurring in the years 2017-2019 when Holyrood is decommissioned and converted to synchronous condenser operation, and the wind capacity is being installed. The deployment of batteries is required to fill the firm capacity gap due to the substitution of wind for thermal generation.

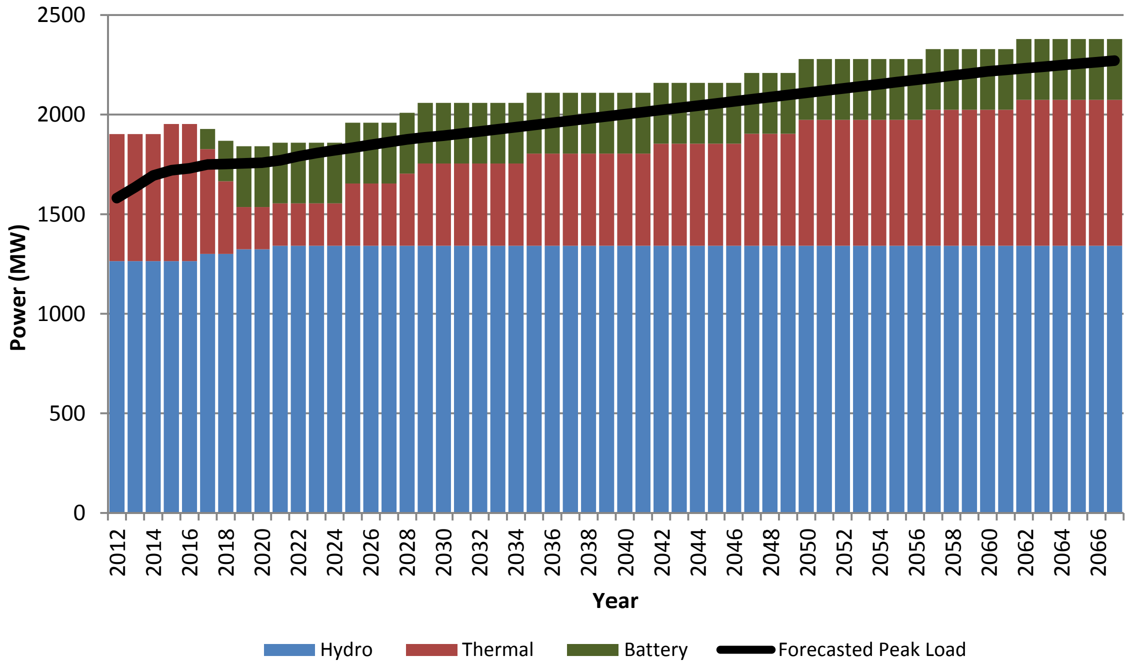

Figure 11: Wind with Battery Backup Scenario – Generation Capacity Chart – 2012 to 2067

The amount of installed wind capacity in this scenario increases from a low of 54 MW in 2012 to a maximum of 1379 MW in 2035. This represents about 40% wind penetration by capacity in 2035. The capacity reserve is much lower than the base case, at around 5%. A Strategist6 optimization study would be recommended to improve the reliability design of this scenario and to ensure that sufficient supply is available to meet island needs. Increasing the size of the battery capacity to match a 14% reserve margin would substantially increase the costs of this scenario.

Figure 12 shows the worst-case contingency used for sizing the battery energy specification. This consists of an ice storm that disables all wind turbines on the island for a period of two days. This is for the year 2024, which is the worst-case year for thermal and hydro capacity reserve. The firm supply is 1554 MW while the peak load is 1821 MW. The capacity deficit is shown by the distance between the system hourly requirement and firm capacity lines, which is made up by the battery energy (red shaded area). Day one begins with a fully charged battery that depletes throughout the day, until the load drops below the firm supply capacity for the night. Some amount of energy is available for re-charging the battery

[6] Resource Portfolio Strategist is a software tool used by utilities which incorporates load forecasts, resource characteristics, electric and fuel prices, and various constraints to optimize a generation resource plan.

through the night (blue shaded area). Day two begins with a partially discharged battery, where the same worst-case load profile discharges the battery to the minimum level corresponding to 20% state of charge. This is assumed a safe level for effective battery management for Lithium Ion battery technology. A 5929 MWh battery exactly meets this requirement. It is assumed after day two it would be possible to start some wind generation again or make agreements to shed load to keep the island power system operational.

One anticipates that the batteries would be routinely cycled to fill in the gaps when the wind is off due to the same conditions described in the back-up CT case (low speed cut out, high speed cut out, and when the wind drops below 511.5 MW). It is assumed that under this scenario, the batteries would have a 10-year life.

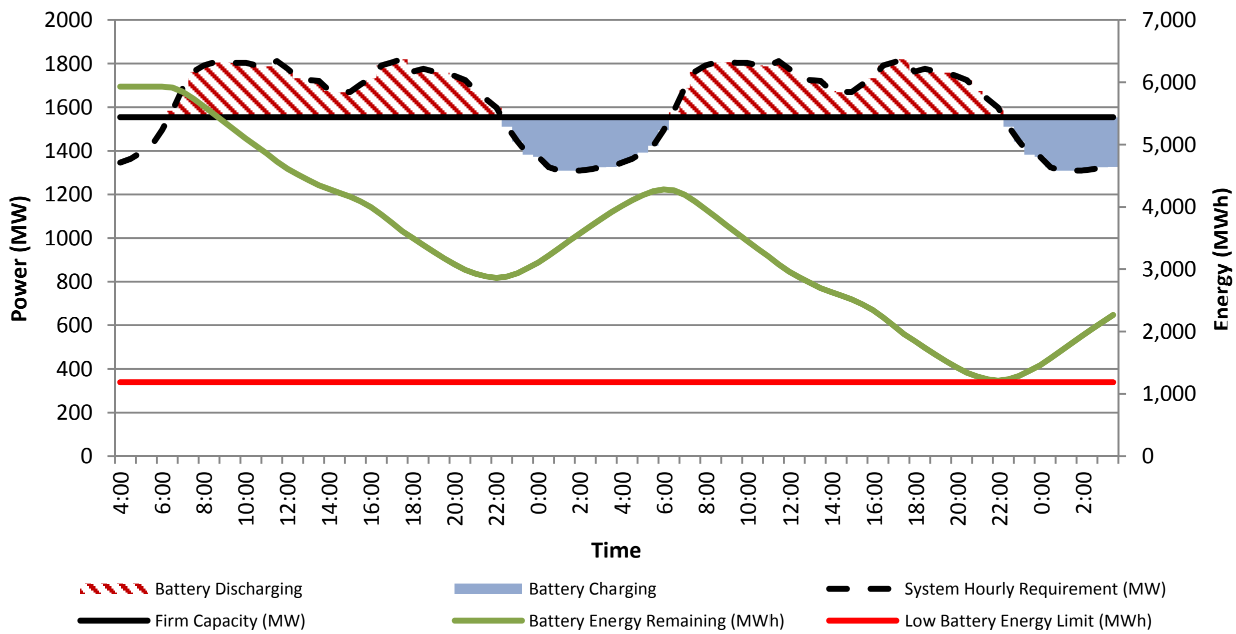

Figure 12: Wind with Battery Backup Scenario – Two-Day Wind Outage Energy Balance

3.4 Cumulative Present Worth (CPW) Analysis of Scenarios

The evaluation metric selected for comparing the cost of each scenario is Cumulative Present Worth (CPW). The CPW technique is used to determine the present worth of all identified fixed, operations, maintenance, and fuel costs over the study horizon to 2067. This CPW method is the same used by Nalcor in comparing costs between their Interconnected option (Muskrat Falls hydroelectric development) and the Isolated Island option, and can therefore be used to make direct cost comparisons between Nalcor's two options and the large scale wind development options presented in this review.

Nalcor's Decision Gate 3 model for calculating CPW was used as the template for this wind analysis, relying on the same cost forecasts and parameters as used by Nalcor where appropriate. These factors include the discount rate, nominal escalation rates, and fuel price forecast. Except where changes and additions to Nalcor's capital investment plan were required, the timing, sizing, and costing of incremental generating plants were used in Nalcor's Isolated Island option, including the energy produced by all plants in Nalcor's CPW model. The only substantive changes to Nalcor's investment plan were in the following areas:

- 1100 MW total new wind capacity added in 2014-2019, plus replacements every 20 years into the future
- Associated circuit breakers and transmission lines for each new wind farm, plus future replacements
- Transmission station additions or refurbishment to link new wind capacity to the Island grid
- Use of Holyrood Thermal Generating Station for synchronous condenser capacity, plus an additional 650 MVAr of new synchronous condensers
- Additional capacity (Batteries or CTs) required to meet worst-case capacity requirements when wind is not available to operate the 1100 MW wind plant

The capital and operating costs for 1100 MW of new wind turbines and the battery storage assets are based on data held by MHI from internal studies and other industry data. MHI's operating costs for the new wind plants are lower in annual fixed costs, but approximately twice Nalcor's variable cost, owing mostly to additional costs of wind integration expected for such a high wind penetration. Although there is evidence to suggest that both wind turbines and battery technology will continue to improve and likely decline in real costs over time, no cost reductions were applied to future asset replacements in this CPW analysis.

A major operating cost reduction arose due to the substitution of Holyrood and its subsequent CCCT replacements for the new 1100 MW of wind capacity. As new wind capacity comes into service, Holyrood's generation and consequent fuel costs are scaled down until the entire 1100 MW of wind is in-service in 2019. Nalcor's original CCCT plants are precluded by the new wind plants and backup assets, and all the respective fixed and operating costs are removed from the CPW. To model this, the total consumption of No. 2 fuel oil listed in the Nalcor CPW was credited by the amount of fuel that is saved by eliminating the CCCTs, using the appropriate heat rate provided by Nalcor.

In the battery scenario, MHI introduced 5,929 MWh of battery capacity in the period 2017-2019, for a 2012 cost of $4.447 billion. These batteries are also replaced every 10 years in the analysis. In the partial thermal scenario a total of eleven 50 MW CTs were added over the period of 2014-2023, for a total of $793 million. In both scenarios, the 1100 MW of new wind capacity plus associated breakers and transmission assets totals to $3.84 billion, and the synchronous condensers total $202 million. All these incremental assets are replaced at their end-of-life for the entire study horizon until 2067, and those costs are incorporated into the CPW. Table 5 compares the CPW values for each of Nalcor's two existing options, plus the two new scenarios analyzed by MHI for a wind replacement of the Holyrood Thermal Generation Station.

Table 5: Cumulative Present Worth of Studied Scenarios

	Cumulative Present Worth (Billions in 2012)			
CPW Cost Component	**Interconnected Option**	**Isolated Island Option**	**Wind & Thermal Scenario**	**Wind & Battery Scenario**
Fixed Charges	$0.32	$2.56	$7.27	$14.61
Operating Costs	$0.26	$0.75	$1.29	$1.18
Fuel Costs	$1.32	$6.71	$0.87	$0.87
Backup CT Fuel Costs	$0	$0	$1.67	$0
Power Purchases	$6.47	$0.76	$0.76	$0.76
Total	**$8.37**	**$10.78**	**$11.86**	**$17.43**

3.5 Suggested Future Work

Due to time constraints, no power system simulation study tools were used for the technical assessment and benchmark criteria were applied to hand calculations to complete this work. Therefore, the results and conclusions herein are to be considered as a screening level study only. In order to improve the accuracy and reliability of the metrics calculated beyond the screening study level (AACE Class 4), the following additional work would be required at a minimum:

- A full electrical power resource plan would be required for each scenario including hydrology modelling
- Detailed power system engineering and system studies would be required including:
- Load flow analysis
- Fault analysis
- Dynamic stability analysis
- Voltage regulation analysis
- Identify and analyze additional locations for dispersal of wind farms
- Detailed wind farm site selection and measurement
- Determination of required transmission, distribution, and generation upgrades

- Engineering and budgetary pricing for all identified equipment and work
- Revision to the Cumulative Present Worth (CPW) analysis of all identified capital and operating costs, per alternative.

Inevitably, in the course of performing this additional work, the CPW of each new option would increase as new requirements are identified. Comparing CPW of these large-scale wind development options to the existing Decision Gate 3 Isolated Island and Interconnected options should consider the advanced technical maturity of those estimates.

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4 Conclusion

Two recent reports on the development of wind for the Isolated Island of Newfoundland were reviewed; Hatch's Wind Integration Study - Isolated Island and Nalcor's Wind Integration – Voltage Regulation and Stability Analysis. Both reports are technically sound and meet their study goals.

The second deliverable of this report is to answer the questions "In an isolated island scenario, can sufficient wind be developed to replace the Holyrood Thermal Generating Station and meet future demand? Is this a technically feasible and economic alternative to Muskrat Falls?" A high-level desktop exercise was performed to evaluate two potential options for replacement of thermal generation for the Isolated Island of Newfoundland via large-scale wind development. Possible locations for the wind farms were selected based on available wind energy maps, proximity to load centers, and details of the existing 230kV transmission network. Technical challenges such as low inertia and low fault levels associated with exceeding 10% wind penetration were met with the widespread application of synchronous condensers.

Since new wind generation can be assigned no firm capacity credit, it must be backed up by firm, dispatchable energy sources. Two options were explored in order to meet this requirement; deployment of a massive battery bank, and deployment of low capital but high energy cost combustion turbine (CT) generators. The expected usage of backup sources is comparatively low in energy terms, which compensates partly for the increased capital expenditures. Backup dispatchable capacity assets are necessary to meet load requirements during no wind conditions such as becalming, ice storms, and over speed conditions if electrical system reliability is to be maintained.

Finally, Cumulative Present Worth analysis was performed on each of the large-scale wind development scenarios, which are evaluated against the existing Nalcor CPW metrics for the Muskrat Falls and thermal Isolated Island options. The Wind and Battery scenario is the most costly option, while the Wind and Thermal option is a more reasonable cost, but is still more costly than the Muskrat Falls and thermal Isolated Island options. Given the nature of the estimates for both wind scenarios, one anticipates that capital costs would increase further with detail study and engineering. Also, the back-up CT wind option has some risk exposure to fuel variability as backup CTs must be run to make up for energy shortfalls when the wind is off, or falls below system load requirements.

One must be cautioned on the nature of the outcomes of this assessment as a great deal more work is required to technically evaluate the feasibility of the Holyrood Thermal

Generating Station wind replacement scenario. That is, in order to determine if system voltages, loadings and frequency are within acceptable limits with up to 1379 MW of wind power in operation during normal and disturbance (fault) conditions, more simulation studies must be undertaken. These studies could lead to the addition of more equipment such as, static VAR compensators, reactors, new protection and control systems, etc. The scenario and mode of wind operation theorized in this study has not been demonstrated elsewhere in the world for an isolated island grid. In addition, the 1379 MW wind alternatives have a higher risk profile considering the high levels of wind penetration proposed together with the many issues that need to be studied.

Based on these screening level study findings (at an AACE Class 4 estimate), and the risks inherent in such a massive wind development, MHI does not recommend that the wind options beyond a 10% penetration level, the level recommended by the 2012 Hatch study for the Isolated Island Option, be pursued at this time. Investment in the Muskrat Falls Interconnected option provides a firm supply, and an opportunity to monetize the excess energy once another interconnection is made. The wind power scenarios do not provide the same value for the $11.86 or $17.43 billion costed over the study period. One must note that the wind scenarios examined are still largely a thermal generation resource plan once the Holyrood Thermal Generating Station is replaced.

MHI finds that large-scale wind development, as a replacement for Holyrood Thermal Generating Station is not a least cost option at this time.

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