Q. **Reference: Renewable Energy Study, page 2 (p. 86 pdf)**

Citation:

> The available renewable energy system capacity was calculated by subtracting the minimum diesel generation limit from available system load data for each 15 minute interval throughout an entire year. Each of these points were then added together to determine the potential energy that could be provided through renewable generation to offset diesel fuel.

a. Please confirm that the values determined in this study represent the maximum amount of renewable energy that can be integrated into the diesel system, without reference to the actual renewable energy generation potential in the region.

b. Has Hydro undertaken a survey or a review of the wind and solar energy potential in the southern Labrador region? If so, please summarize the results and provide copies of the relevant studies. If not, what does Hydro consider to be a reasonable estimate of the amount of cost-effective wind and/or solar power likely to be developed in the region by 2035.

c. Has Hydro explored the possibility of developing wind or solar power in the region on its own behalf? If not, why not?

d. Please describe Hydro's policy with respect to signing power purchase agreements with independent renewable energy generators in Labrador.

A.

a. It is confirmed that the values determined in this study represent the maximum amount of renewable energy that can be integrated into the diesel system without reference to the actual renewable energy generation potential in the region. They also assume that there must always be at least one diesel generator in operation.

b. Newfoundland and Labrador Hydro ("Hydro") has undertaken a number of studies related to wind and solar energy potential across all of its isolated systems in Labrador, as follows:

“Preliminary Assessment of Alternative Energy Potential in Coastal Labrador – 2009” (LAB-NLH-015, Attachment 1)

The “Preliminary Assessment of Alternative Energy Potential in Coastal Labrador – 2009” study was a joint venture between Hydro and the Government of Newfoundland and Labrador to investigate the potential for the integration of alternative energy sources including solar, wind, and small-scale hydroelectric facilities into isolated communities that rely on diesel generation as a primary means of electricity.

This was a preliminary undertaking and is fairly dated in terms of technology considered, modelling efforts, etc. The results therefore may not represent a reasonable estimate of the current amount of cost-effective wind and/or solar power likely to be developed in the region by 2035.

Seven communities were selected for the study: Cartwright, Charlottetown, Hopedale, Makkovik, Mary's Harbour, Nain, and Port Hope Simpson. Weather stations were deployed in each of these communities to collect information on the wind speed, rainfall, and solar radiation experienced in each community.

This report concluded that, based on the existing weather data, it is reasonable to confirm that Labrador possesses alternative energy resources that, under the right economic conditions, could be developed to reduce the usage of diesel generation in many communities. While the amount of potential cost effective wind/solar generation varies by system, this report concluded that the potential economical penetration of renewable energy varies from approximately 5% to 40%, depending on the individual system.

“Coastal Labrador Wind Monitoring Program – 2015” (LAB-NLH-015, Attachment 2)

In 2015, Hydro engaged Hatch to perform a wind resource assessment for five communities in coastal Labrador: Nain, Hopedale, Makkovik, Cartwright, and L’Anse-au-Loup. The objective of the study was to identify potential windy areas that also possess other desirable qualities of a wind energy development site.

This study included:

- Preliminary site assessment that include environmental screening, site visits, permitting and the preliminary evaluation of factors such as wind and constructability;
- Installation of meteorological towers for 18 months;
- Wind resource assessments for each community; and
- Preliminary evaluation of the feasibility of integrating wind with each of the communities' diesel-fueled electrical generators and to establish the potential economic viability of the projects.

The "Coastal Labrador Wind Monitoring Program – 2015" study concluded that the implementation of wind turbines in four of the five communities has potential and could possibly result in reductions in diesel consumption if integrated correctly. The average potential fuel savings for the four communities was determined to be approximately 42%. This study did not include assessment of the viability and cost associated with energy storage required to provide firm capacity with wind generation. The overall business case for the investment remains to be validated as additional studies and community consultation will be required prior to completion of the final design.

"Labrador Interconnection Option Study – 2020" (LAB-NLH-015, Attachment 3)

The "Labrador Interconnection Option Study – 2020" was completed by Hatch for Hydro to assess seven different options at a preliminary level to reduce diesel fuel consumption in Hydro's isolated communities. This includes options to fully interconnect isolated systems to the North American grid, partial interconnection of isolated systems in larger isolated grid systems, and continued isolation with significant renewable integration.

This study concluded that the lowest cost option is the base case operation, keeping the diesel gensets within each community; however, it did not consider the savings associated with avoiding diesel unit and diesel plant replacements costs, such as the ones identified in this application. It is also important to note that this study was limited in scope, to consider how partial interconnection of isolated systems could further allow renewable energy development. Through further refinement of the cost-benefit analysis, taking into account asset replacement costs, Hydro concluded that regional interconnection supplied by a regional diesel plant is the least-cost alternative for the long-term supply of firm capacity for the southern Labrador region, as outlined in Schedule 1, Attachment 1 "Long-Term Supply Study for Southern Labrador: Economic & Technical Assessment".

c. Hydro has decided not to develop wind or solar power in the region on its own behalf as it has been identified within the *Labrador Interconnection Options Study* that the total cost of ownership of wind generation and storage to supply approximately 50% of energy, based on a 20-year study period, is approximately 50% higher than that of the continued operation of individual diesel plants, an option which Hydro has concluded is more expensive alternative than regional interconnection supplied by a single regional diesel plant. Further, the provision of 50% of energy from renewable sources would still require diesel generation to provide the remaining energy and provide firm capacity in the event of reduced renewable generation.

Although Hydro has determined that development of wind and solar power in the region on its own behalf is not the least-cost alternative, Hydro is willing to engage in discussions for power purchase agreements with independent power producers who may be able to avail of different funding opportunities which enable them to cost-effectively develop renewable facilities so long as the outcome of such an arrangement would result in the provision of least-cost power for Hydro's customers.

d. Hydro is currently a signatory to two power purchase agreements ("PPAs") with independent renewable energy generators for power in Labrador. These PPAs were signed based on the fact that the cost of purchases under these PPAs is lower than would be incurred by Hydro to generate equivalent energy using its own diesel generation. Therefore, these PPAs support Hydro in fulfilling its mandate, as per the *Electrical Power Control Act*, of ensuring "lowest possible cost consistent with reliable service." While no formal policy exists, absent changes to the legislation governing Hydro, Hydro expects that only PPAs that support this mandate would be signed.

By signing PPAs with independent power producers, customers are protected from all risks associated with capital and operating costs for renewable energy projects. Hydro serves as a system integrator and works with power producers to ensure the reliable interconnection of all third-party facilities.

PRELIMINARY ASSESSMENT OF ALTERNATIVE ENERGY POTENTIAL IN COASTAL LABRADOR

Date: December 2009

newfoundland labrador hydro
a nalcor energy company

EXECUTIVE SUMMARY

The Coastal Labrador Alternative Energy study is a joint venture between Newfoundland and Labrador Hydro (Hydro) and the Government of Newfoundland and Labrador. In 2009, Government invested approximately $250,000 for Hydro to investigate the potential for the integration of alternative energy sources, including solar, wind and small scale hydroelectric facilities into isolated communities that rely on diesel generation as a primary means of electricity.

To ensure the success of the study, coastal Labrador communities were pre-screened for the project based on specific criteria developed by Hydro. The criteria included: annual minimum load of 200 kilowatts, forecasted growth in electricity consumption over the next five years and annual energy consumption in excess of 3000 megawatt hours. Based on these criteria seven communities were selected for the study: Cartwright, Charlottetown, Hopedale, Makkovik, Mary's Harbour, Nain and Port Hope Simpson.

Weather stations were deployed in each of these communities to collect information on the wind speed, rainfall, and solar radiation experienced in each community. The weather stations had staggered commissioning dates ranging from April 2009 to August 2009. As a result, there are currently four to eight months of weather data available for each location in the study. Data was compared with information available from Environment Canada, the Canadian Wind Atlas, and NASA's Surface Meteorology and Solar Radiation database.

Hatch Ltd. was retained by Newfoundland and Labrador Hydro to conduct an assessment of the hydraulic potential of the selected communities. Three scales of hydro projects were considered; micro, mini and small.

An assessment of the resources and the economics was completed considering numerous schemes for each location. The economic feasibility evaluation included examination of the annual community power requirements; the energy potential for each resource (i.e. solar, wind, hydro); the possibility of hybrid systems; and the economics for the implementation of each proposed solution.

Study Findings

Wind

Wind is more prevalent in winter months. It provides a nice fit with winter peaking systems. Installation of meteorological towers capable of measuring wind speeds at hub height at sites optimally located for a wind energy installation is recommended for Cartwright, Hopedale, Makkovik and Nain.

Hydrology

36 potential sites were identified, out of which 13 sites were recommended for further consideration. Interconnection possibilities were considered for Port Hope Simpson, Charlottetown, and Mary's Harbour. Three potential sites were identified with two of those capable of meeting the entire energy requirements of all three communities. Some of the hydro generation sites identified are capable of completely displacing diesel generation in certain locations; however, the scope of this study was limited to run-of-river installations. To replace diesel generation in these locations, solutions with storage capability would likely be required. Prefeasibility hydro investigations should be carried out at Sites 4, MK S-1, 5, 1, MH S-2A, 2, MK S-2, MH S-4, PHS S-1, CH S-3, 12, PHS S-3, and PHS S-5.

More detailed mapping should be produced to further delineate the hydro and wind sites. This could be accomplished through a LIDAR Survey covering the sites identified in the study, and could be extended to the whole coast. Such data could potentially yield a greater number of sites, and provide the data necessary to move to the next step.

Solar

Though Labrador has a moderate solar resource, the development and deployment of solar installations remains very expensive and existing technologies have poor energy conversion efficiency. Should the cost of solar energy decrease significantly, it would be worth revisiting the economic feasibility assessment to account for this decrease and determine if solar energy has become a more attractive choice.

In summary, based on the existing weather data, it is reasonable to confirm that Labrador possesses alternative energy resources that, under the right economic conditions, could be developed to reduce the usage of diesel generation in many communities.

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INTRODUCTION

1.1 Objective

The Coastal Labrador Alternative Energy study is a joint venture between Newfoundland and Labrador Hydro and the Government of Newfoundland and Labrador. In 2009, Government invested approximately $250,000 for Hydro to investigate the potential for the integration of alternative energy sources into isolated, off-grid communities that rely on diesel generation as a primary means of electricity. This initiative consisted of an evaluation of the renewable resources available in selected communities and a preliminary feasibility assessment of the financial and technical requirements associated with integrating alternatives in the existing energy systems. Energies explored included solar, wind and small-scale hydroelectric facilities. As the study is a preliminary assessment of resources available in the identified communities, its main objective is to distinguish sites where development is technically and economically feasible from those where it is not. Further assessment of the resource potential is required before advancing with any potentially feasible projects. A full list of recommendation can be found in Section 6.2 Recommendations.

This initiative is primarily guided by the two main objectives outlined in the Newfoundland and Labrador Energy Plan: protection of the environment through the reduction of emissions, and the development of energy projects in the best long-term interests of residents of the province. Through integration of renewable energy systems, fuel consumption and the operating costs of the diesel generation facilities can be reduced.

1.2 Scope of Work

The scope of work was as follows:

- Determine a set of criterion to screen potential communities, ensuring identification of the communities with the greatest likelihood of success.
- Select and deploy weather monitoring stations in each of the selected communities.
- Retain consulting services to assess hydraulic potential in identified communities.
- Collect information from weather stations concerning wind and solar energy potential in the selected communities.
- Perform economic analysis for each location using detailed cost information for each energy alternative.
- Model data to determine the most promising alternatives for each location.

It is important to note that this study will provide preliminary estimates of the alternative energy potential available at each of the sites in question. The methods employed to determine the availability and quality of the resources is only suited to preliminary inquiries. The conclusions of this study will provide recommendations for further suggested investigation and action based on these results.

1.3 Background

Newfoundland and Labrador Hydro operates 22 isolated diesel systems province wide, 16 of which are located in Labrador. The forecasted energy demands for 2009 were used as the baseline for the energy requirements for each system, and the forecasted energy demands for 2011 through 2015 were used for modeling and subsequent analysis. Town locations are illustrated below.

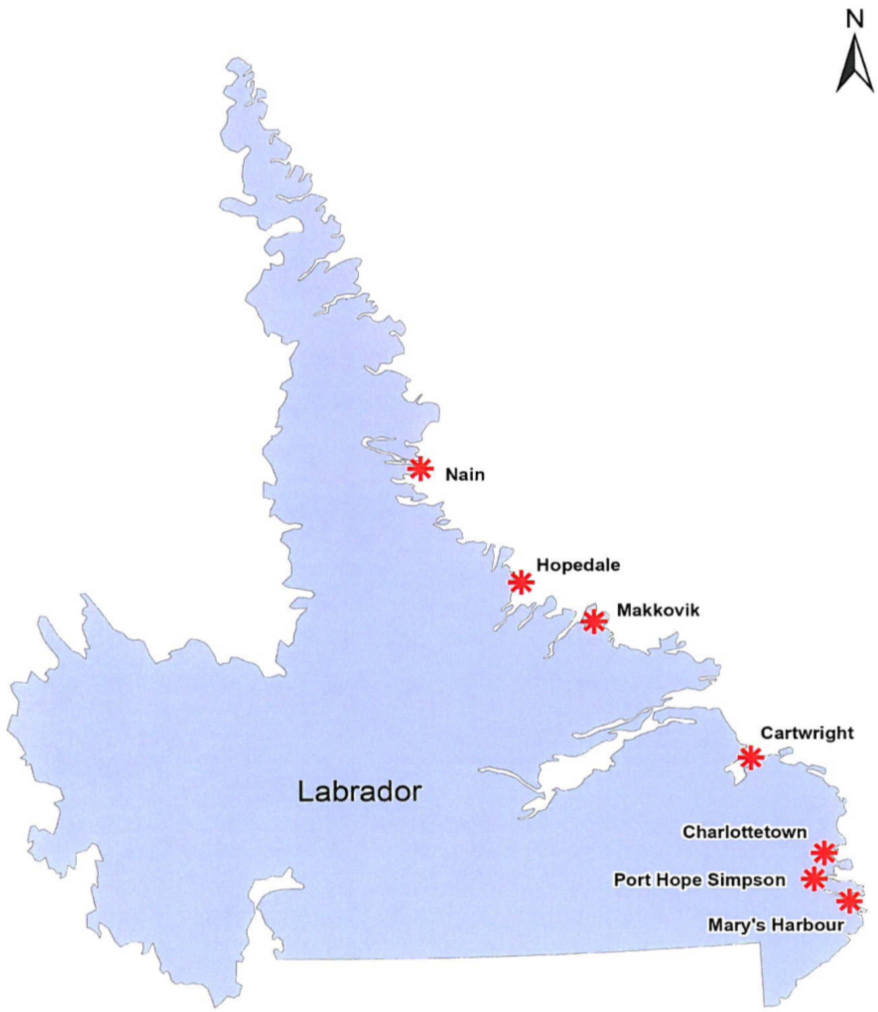


Figure 1 - Communities under study

1.3.1 Nain

Nain is both the northernmost and largest community considered in the alternative energy study, with a population of approximately 1000 (1). In keeping with home heating requirements due to its northern position, Nain experiences its highest peak loads and net energy consumption during the winter months. This is illustrated in Figure 2 - Nain 2008 Monthly Net Peak Load and Figure 3 - Nain 2008 Monthly Net Energy. Nain is classified as a winter peaking system.

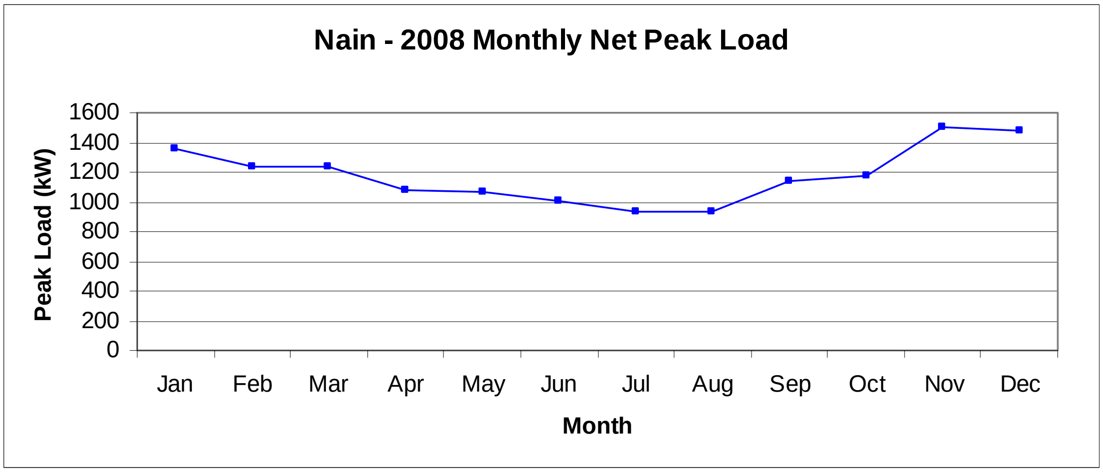


Figure 2 - Nain 2008 Monthly Net Peak Load

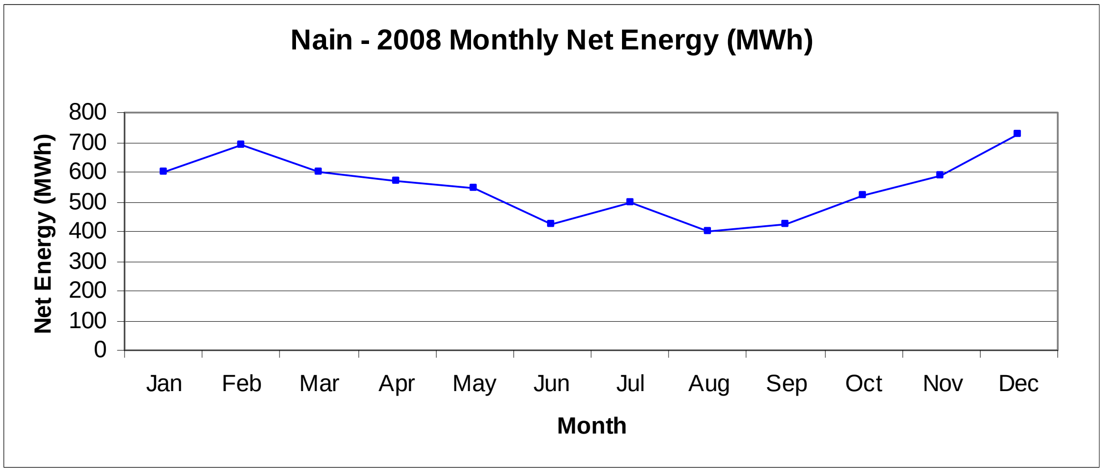


Figure 3 - Nain 2008 Monthly Net Energy

1.3.2 Hopedale

Hopedale is one of the more northern communities studied, situated on the northern Labrador coast. It has a population of approximately 530 people (1). Due to its northern location, the Hopedale system typically experiences its peak demand and highest energy requirement during winter months, as heating requirements and subsequently furnace usage and energy required for water heating are typically higher during these months. This is illustrated in Figure 4 - Hopedale 2008 Monthly Net Peak Load, and Figure 5 - Hopedale 2008 Monthly Net Energy. Hopedale is thus classified as a winter peaking system.

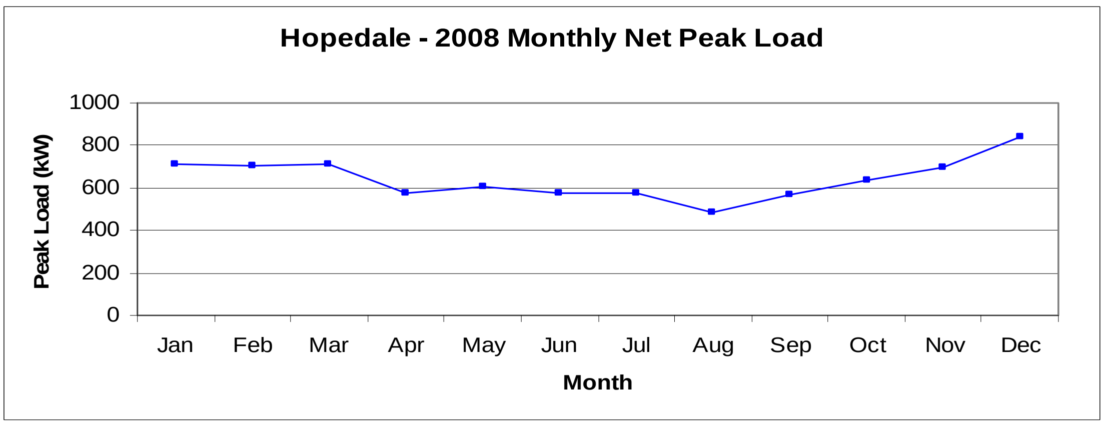


Figure 4 - Hopedale 2008 Monthly Net Peak Load

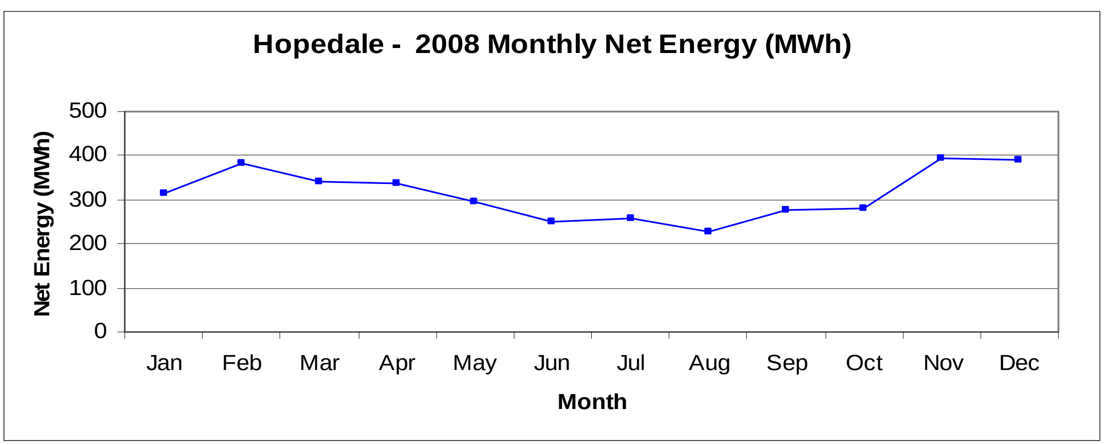


Figure 5 - Hopedale 2008 Monthly Net Energy

1.3.3 Makkovik

Makkovik is a northern community with approximately 360 inhabitants (1). As evident in Figure 6 - Makkovik 2008 Monthly Net Peak Load, Makkovik experiences two periods of high net peak loads; one in July and August, the other in December. The summer system peak is due to the seasonal operation of a local crab plant. The winter system peak is due to increased home heating requirements. These observations are strengthened by examining Figure 7 - Makkovik 2008 Monthly Net Energy, as highest energy consumption coincides with these system peaks.

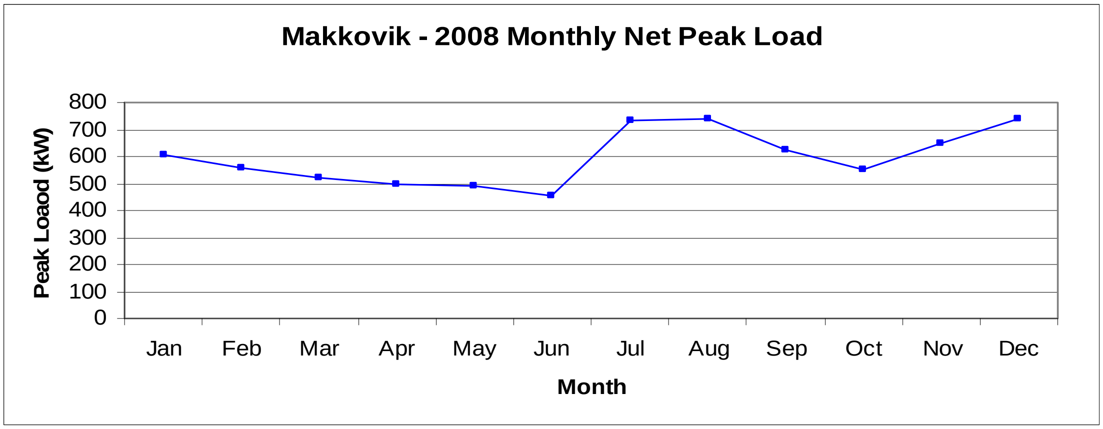


Figure 6 - Makkovik 2008 Monthly Net Peak Load

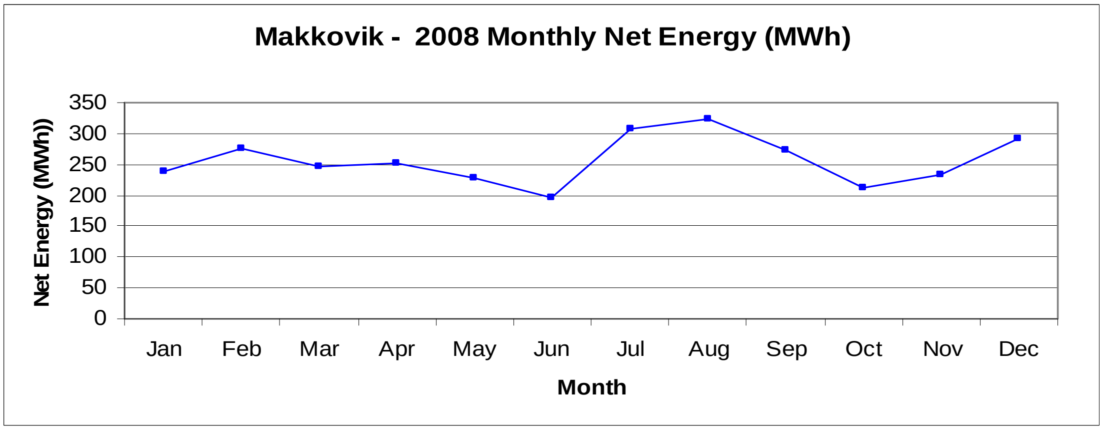


Figure 7 - Makkovik 2008 Monthly Net Energy

1.3.4 Cartwright

Cartwright is a community with a population of approximately 550 people (1), located at the entrance of Sandwich Bay. As evident in Figure 8 - Cartwright 2008 Monthly Net Peak Load, highest system loads typically occur in June and July. In addition, as shown in Figure 9 - Cartwright 2008 Monthly Net Energy, the highest energy consumption also occurs in this time period. These findings are as expected, due to the seasonal operation of a local crab plant. As a result, Cartwright is classified as a summer peaking system.

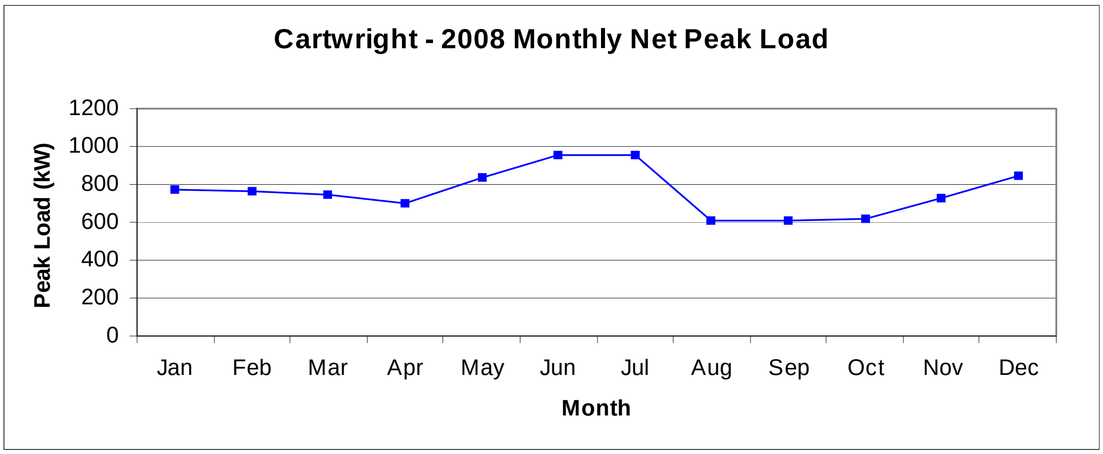


Figure 8 - Cartwright 2008 Monthly Net Peak Load

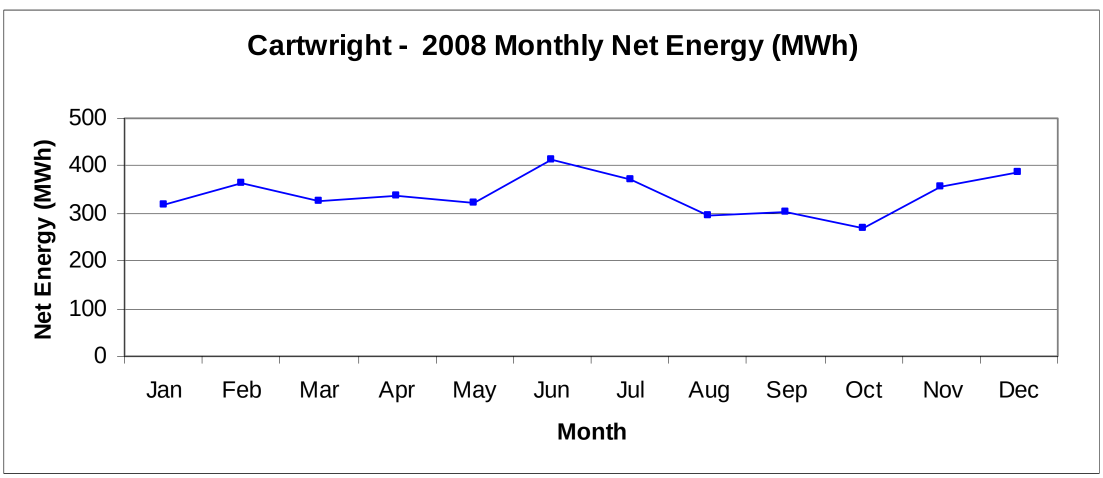


Figure 9 - Cartwright 2008 Monthly Net Energy

1.3.5 Charlottetown

It is one of the smaller communities included in the Coastal Labrador Alternative Energy study with a population of approximately 360 people (1). As evident in Figure 10 - Charlottetown 2008 Monthly Net Peak Load, Charlottetown experiences its highest system loads between June and August. In addition, July and August exhibit the highest net energy consumption, as illustrated in Figure 11 - Charlottetown 2008 Monthly Net Energy. These findings are as expected, due to the annual operating period of the local shrimp plant. As a result, Charlottetown is classified as a summer peaking system.

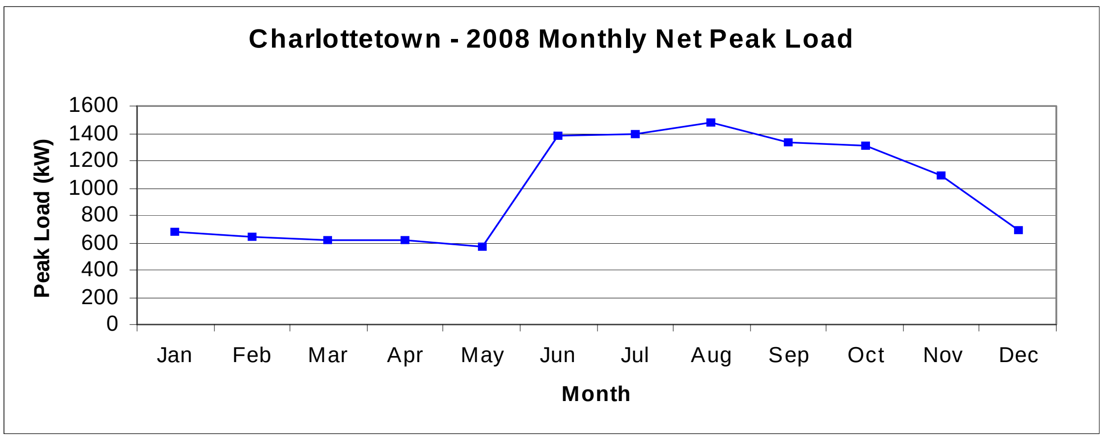


Figure 10 - Charlottetown 2008 Monthly Net Peak Load

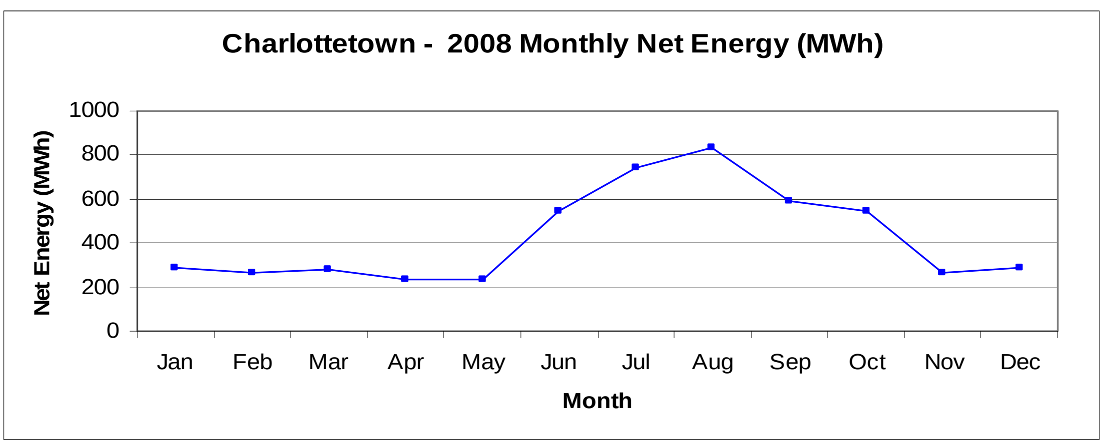


Figure 11 - Charlottetown 2008 Monthly Net Energy

1.3.6 Port Hope Simpson

Port Hope Simpson is located in southern Labrador at the mouth of the Alexis River. It has a population of approximately 529 people (1). As illustrated in Figure 12 - Port Hope Simpson 2008 Monthly Net Peak Load and Figure 13 - Port Hope Simpson 2008 Monthly Net Energy, Port Hope Simpson experiences highest system loads and net energy consumption during winter months. As a result, Port Hope Simpson is classified as a winter peaking system.

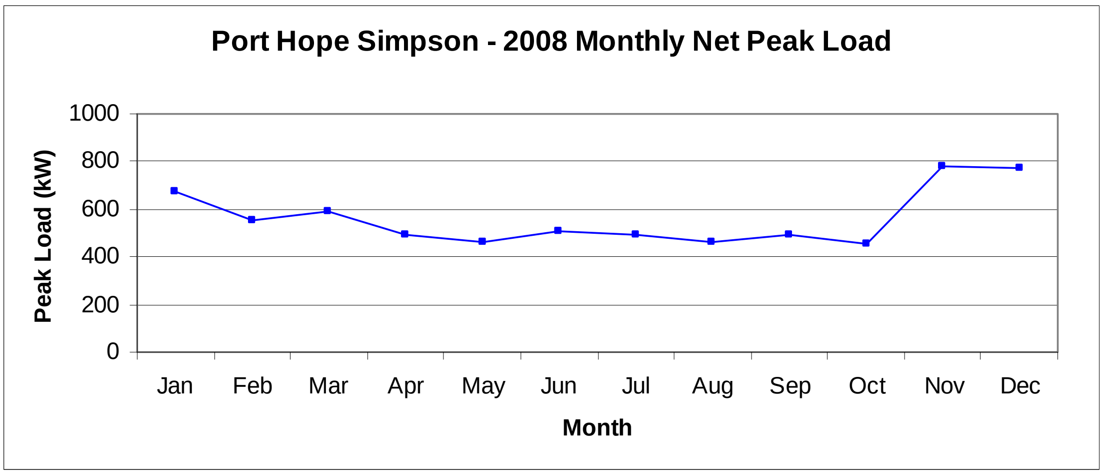


Figure 12 - Port Hope Simpson 2008 Monthly Net Peak Load

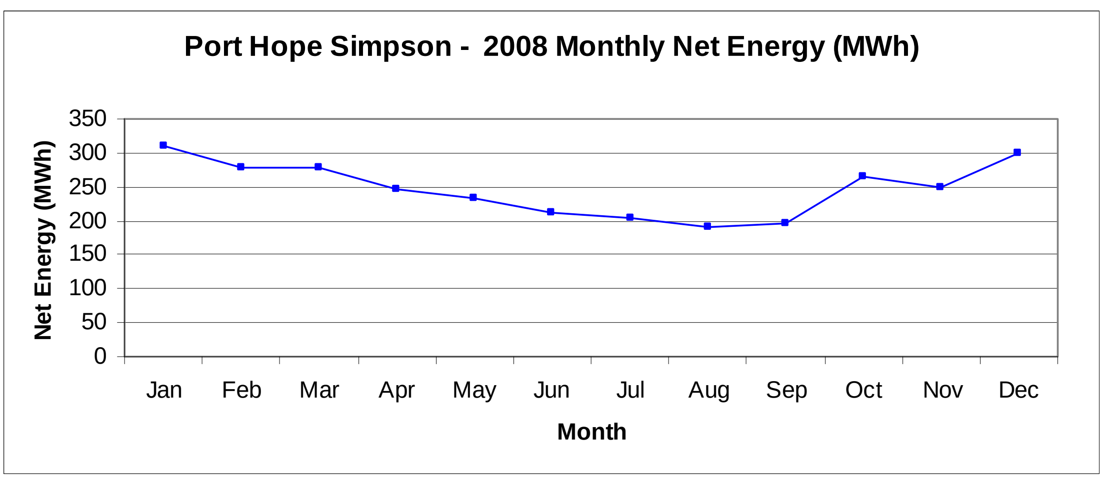


Figure 13 - Port Hope Simpson 2008 Monthly Net Energy

1.3.7 Mary's Harbour

Located on the southern coast of Labrador, Mary's Harbour is located at the mouth of the St. Mary's River. The community has a population of approximately 417 people (1). As illustrated in Figure 14 - Mary's Harbour 2008 Monthly Net Peak Load, Mary's Harbour experiences peak loads during the summer months, due to seasonal operation of the local crab processing facility. This is supported by Figure 15 - Mary's Harbour 2008 Monthly Net Energy, illustrating highest energy consumption in June. It is important to note that the illustrated May peak load in Figure 14 is a possible anomalous value. The value of the same reading for 2007 was 644 kW and for 2009 was 702 kW. It is expected the May 2008 value should have read somewhere in this range. Mary's Harbour is classified as a summer peaking system.

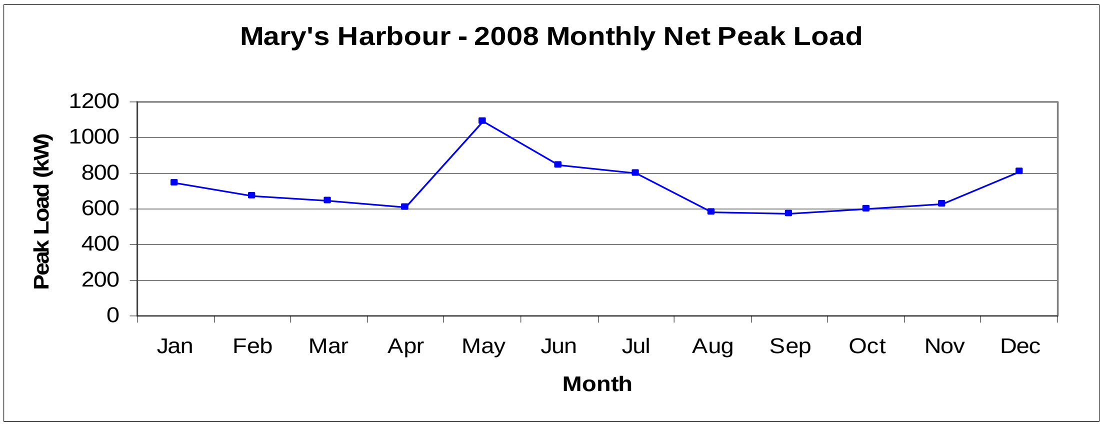


Figure 14 - Mary's Harbour 2008 Monthly Net Peak Load

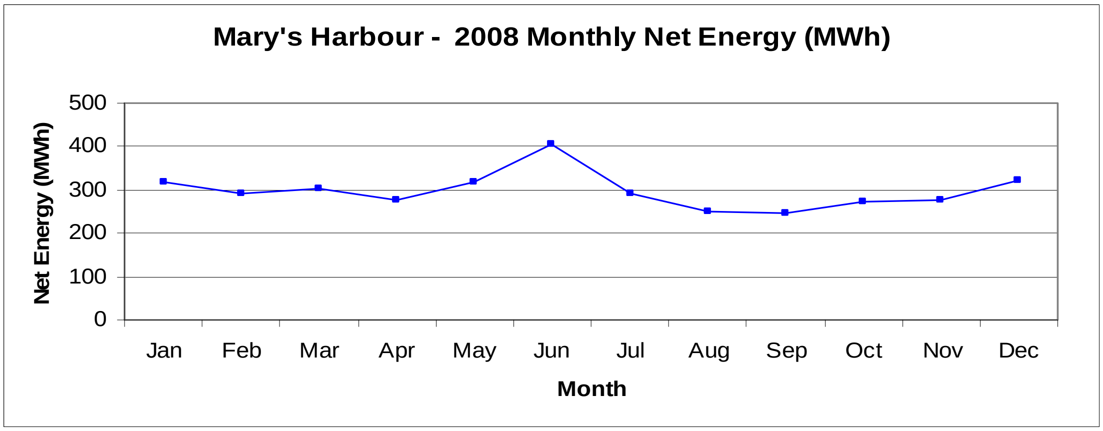


Figure 15 - Mary's Harbour 2008 Monthly Net Energy

2 METHODOLOGY

To determine the existing energy potential in each location, it was necessary to decide what energies to focus on, obtain as much weather data for each site as possible, and model collected data to assess economic viability.

2.1 Community Selection

Due to the large number of isolated systems in coastal Labrador, it was decided to narrow the scope of the study to only include those communities which had the greatest likelihood of technical success. The integration of alternative energy sources into an isolated system is a technically challenging feat. Since the alternative energy sources such as solar, wind, and run-of-river hydro are continuously random and variable, they cannot be installed to provide capacity for the system. Rather they provide energy to the system in continuously varying amounts and serve to displace energy produced by burning diesel fuel. To ensure the system has adequate capacity (energy required by the load at any instant), the alternative energy must be electrically paralleled with the existing diesel generators. In addition, the available potential and volatility of the alternative energy source can have unpredictable effects on the system; if the source is too small, much of the available energy will not be converted into electricity, if the source is too large, system stability and quality issues rise to the forefront.

A set of selection criteria was developed by Newfoundland and Labrador Hydro to pre-screen communities for inclusion in the study. The criteria were as follows:

1) Annual minimum load equal to or in excess of 200 kW in 2007.
2) Annual energy consumption equal to or in excess of 3000 MWh in 2007.
3) Growth in consumption forecasted for the system over the five-year forecast horizon.

Based on these criteria, seven communities were selected: Nain, Hopedale, Makkovik, Cartwright, Charlottetown, Port Hope Simpson, and Mary's Harbour.

2.2 Alternative Energies Considered

The solar, wind, and hydraulic potential of each location was studied. These three were chosen since reasonable potential was expected in these locations and the economics associated with these ventures does not make them prohibitive in small, isolated communities. In addition, these alternative energies are more widely used and are better known.

Hydro projects were considered on three scales: small, mini, and micro. A request for proposal (RFP) for consultant services was issued in April with awarding of the contract to Hatch Ltd. in May for completion in October. Solar and wind energy analysis was completed by Newfoundland and Labrador Hydro's System Planning department.

2.3 Data Sources

2.3.1 Weather Stations

Eight weather stations were purchased to assist in the determination of possible energy resources. Seven were deployed in Labrador, with one in each of the communities studied. The eighth station was kept in office for configuration and testing purposes.

The choice of weather station was an important decision made in the early part of the project. A Request for Quotation (RFQ) was issued for public tender in November 2008. From the proposals submitted, the Davis Vantage Pro2 was selected for deployment. For the purposes of this study, the Vantage Pro2 was required to monitor and record wind speed, solar radiation, and rainfall amounts.

The weather stations had staggered deployments from April through August 2009. All seven systems were operational in August 2009. As a result, there is currently four to eight months of complete data sets available for each location. For more information on data collected for a specific location, please refer to the appendix for that community.

2.3.2 Other Sources of Data

Due to the date of deployment of the weather stations, it was not possible to gather one complete year of data before beginning analysis and evaluation. As a result, it was necessary to obtain alternate sources of data capable of providing this information.

Environment Canada operates and maintains a National Climate Data and Information Archive. The archive provides an online collection of official climate and weather observations from across Canada. Through this resource wind speed information was obtained for five of the seven locations. Cartwright, Hopedale, and Makkovik each have an Environment Canada weather monitoring station in the community. Both Mary's Harbour and Nain each have two Environment Canada weather stations. One is located in the community, and the other at the local airport. Though this resource could not provide detailed historical information for Charlottetown and Port Hope Simpson, their geographic proximity to Mary's Harbour and the similarities in the measured data for the locations made the use of available Mary's Harbour data suitable for initial model development.

The Environment Canada Canadian Wind Atlas also provided valuable information on the wind resources to be expected in each of the locations. The Canadian Wind Atlas models long term atmospheric data and statistical properties to obtain a small scale picture of the wind speeds in a particular area. Unlike the National Climate Data and Information Archive, the information provided by the Canadian Wind Atlas is purely theoretical and is not based on actual recorded measurements. This data was available for all seven locations.

The NASA Atmospheric Science Data Centre has developed a Surface Meteorology and Solar Energy website for use by the general public. This website uses information from over 200 satellites to derive meteorology and solar energy parameters. Collected information is then monthly averaged over 22 years of data. This provided accurate monthly solar radiation data for each of the seven locations in the study.

2.4 HOMER

Developed at the United States National Renewable Energy Laboratory, HOMER is a powerful software tool for economic analysis of renewable power systems, distributed power systems, and hybrid power systems. It allows users to model off-grid and grid-connected systems that consider numerous alternative energies. Based on the user supplied information, HOMER runs a series of calculations and returns a list of options that meet the system load demand, ranked in terms of cost-effectiveness. This software is available online free of charge.

HOMER uses a sensitivity function to illustrate how the economics of a particular project can vary with alterations in input. In the HOMER models developed for this study, the sensitivities used included scaled annual average flow, to account for hydro installations on different rivers within one community model, fuel price, to monitor economics as fuel price increases, and scaled annual average load, to monitor economics as system load increases. The sensitivity values used for scaled annual average flow were derived from the Hatch Review of Hydraulic Potential of Coastal Labrador study. The sensitivity values used for fuel prices were obtained using the Nalcor Energy/ Newfoundland and Labrador Hydro Fuel Price Forecast. The sensitivity values used for scaled annual average load were obtained using the Newfoundland and Labrador Hydro Operating Load Forecast Hydro Rural Systems Fall 2010 for the years 2010 through 2015.

2.5 Constraints

Newfoundland and Labrador Hydro remains committed to maintaining a firm generation capacity that can sustain the system load under abnormal operating conditions. The diesel plants currently in operation in the communities involved in this study are capable of continuing to meet the energy demand even in situations where the largest generation unit is out of service. All Hydro's isolated systems must maintain firm capacity.

As the alternative energies considered in this study are non-dispatchable meaning they cannot be called upon to supply energy when demanded, they can only supply energy when it is available. Therefore, none of the energies are capable of completely displacing the diesel plants unless some form of energy storage is incorporated into the system. To date, the alternative energies have only been considered as a means of diesel fuel displacement and the capacity will continue to be supplied by the existing diesel plants. Only run-of-river hydro installations were considered for this study as they are generally significantly lower cost to construct than a facility with a reservoir, and thus the least cost means to develop hydro power.

This means that hydro energy would be dependant on natural run-off; during wet periods, the plant would generate a lot of energy, however, during dry spells it will generate relatively little. Further efforts into the investigation of storage potential at the hydro sites could identify that year-round hydroelectricity could be supplied to the communities.

3 PRELIMINARY COST ESTIMATES

For evaluation in HOMER, cost information was required for each of the energy alternatives. These cost estimates were developed with information from vendors and Engineering Services at Newfoundland and Labrador Hydro. All cost estimates detailed in this section are approximate in 2009 dollars.

3.1 Diesel Generators

The following table details the replacement costs and annual operations and maintenance costs for each of the diesel generators located in the communities being studied.

The replacement cost reflects the purchasing and installation of a new, same-size generator. The operation and maintenance cost is comprised of a base cost, oil replacement cost, and overhaul cost.

Existing Diesel Plant Replacement and Operating Cost Summary (Updated 2009 11 04)						
Location	Region	Unit #	Model	Capacity (kW)	Replacement Cost ($)	Unit Operating Cost ($/yr)
Nain	TRO Labrador Isolated	574	Detroit Series 2000	865	600000	21801
		2085	Caterpillar 3512	1275	1120000	26888
		576	Detroit Series 2000	865	600000	21801
Hopedale	TRO Labrador Isolated	2053	Caterpillar 3412	545	400000	14749
		2054	Caterpillar 3508	448	400000	14749
		2074	Caterpillar 3412	569	600000	14749
Makkovik	TRO Labrador Isolated	2029	Caterpillar D3412	620	600000	16210
		2059	Caterpillar D3412	635	600000	16210
		3033	Caterpillar 3412	450	400000	14749
Cartwright	TRO Labrador Isolated	567	Perkins CV12	470	400000	14749
		2036	Caterpillar D3412	450	400000	14749
		2045	Caterpillar D3412	450	400000	14749
		2052	Caterpillar D3512	720	600000	16210
Charlottetown	TRO Northern Isolated	204	Caterpillar D343	250	380000	9877
		2019	Caterpillar 3406	250	380000	9877
		2034	Caterpillar 3412	300	380000	9877
		2060	Caterpillar 3412	725	600000	16210
		2061	Caterpillar 3412	725	600000	16210
Mary' s Harbour	TRO Northern Isolated	2037	Caterpillar D3412	545	600000	16210
		2038	Caterpillar D3412	545	600000	16210
		2048	Caterpillar 3508	810	600000	21801
Port Hope Simpson	TRO Northern Isolated	2042	Caterpillar 3412	455	400000	14749
		2043	Caterpillar 3412	455	400000	14749
		2073	Caterpillar 3456	455	400000	14749

Table 1 - Diesel Engine Replacement and Operating Cost Estimates

3.2 Wind Turbines

Cost information for the wind turbines is based on the unit cost of NorthWind 100 turbines, as employed in the Newfoundland and Labrador Hydro Wind Turbine installation in Ramea.

Turbine Size		Cost ($)
100 kW	Capital	500,000
	Replacement	400,000
	Annual Operation and Maintenance	10,000

Table 2 - Wind Turbine Cost Estimates

3.3 Solar Panels

Cost information for the solar panel installation was obtained from Carmanah, a leading off-grid solar installation vendor.

Solar Installation Size		Cost ($)
50 kW	Capital	500,000
	Replacement	400,000
	Annual Operation and Maintenance	10,000
100 kW	Capital	940,000
	Replacement	750,000
	Annual Operation and Maintenance	15,000

Table 3 - Solar Installation Cost Estimates

4 ENERGY ESTIMATES

Comprehensive analysis of the various data sources including the weather station meteorological data, the Environment Canada National Climate Data and Information Archive data, the Canadian Wind Atlas theoretical values, the NASA Solar Radiation data, and the HOMER economic viability data was concluded in December 2009.

The analysis was conducted in two parts: the first evaluated the potential of each resource, the second found the maximum amount of energy from each resource that could be utilized in each of the locations with the project remaining economically viable. The first part of the analysis relied heavily on examination of the weather station data, its correlation with the other data sources identified above, and review of the commissioned evaluation of hydraulic potential. The second part of the analysis largely relied on the use of HOMER, though the inputs into HOMER were results from the first stage of data analysis and cost information as detailed in Section 3 Preliminary Cost Estimates.

Though these estimates have been developed following detailed analysis of available data and information, they do not reflect the level of detail required to move to the project development or deployment stages. As this study is a preliminary investigation into the alternative energy potential available in each location, these estimates have been developed to determine if the integration of alternative energies in the considered systems is economically viable and if so, the best alternative energy fit for each location. Further information on the suggested subsequent stages for each location is available in Section 6.2 Recommendations.

In general, wind energy has been found to be more prevalent in winter months, and solar more prevalent in summer months. Some hydro sites have been identified that are capable of meeting or exceeding the forecasted demand. In further studies, investigation into storage potential at these sites would be required before they could be installed with the intention to completely replace the existing diesel plants. Hydro sites with interconnection potential have also been identified. These plants have been identified as capable of serving the system load of all communities in the interconnection with required extra costs, as detailed in the Section 4.3 Hydraulic Potential.

4.1 Wind Energy

Wind energy is thought to have the most promise for the future of alternative energy in coastal Labrador. Most sites studied were found to be able to economically integrate some quantity of wind energy into their generation plan. The amount of energy that could be integrated varied between sites. For detailed, site specific information, please refer to Section 5 Site Evaluation. Monthly wind speed plots, wind duration curves, and average wind speed trends are provided by community in the appropriate appendix.

4.2 Solar Energy

Though Labrador has a moderate solar resource, the development and deployment of solar installations remains very expensive and existing technologies have poor energy conversion efficiency. Should the cost of solar energy decrease significantly, it would be worth revisiting the economic feasibility assessment to account for this decrease and determine if solar energy has become a more attractive choice. Monthly solar radiation plots and clearness index plots are provided by community in the appropriate appendix.

4.3 Hydraulic Potential

Hatch Ltd. performed a screening-level study of the hydraulic potential available in the seven communities. For detailed information on this exercise please refer to the report, Review of Hydraulic Potential of Coastal Labrador, released in November 2009.

Section 6 of the report ranks the potential sites by the ratio of cost to average annual energy in $/kWh. The following tables expand on this estimate and have ranked the hydro options in terms of nominal levelized unit energy costs (LUEC). The LUEC is the estimated cost of producing energy at a specific site. It reflects the minimum price at which the energy can be sold to break even on the project. Table 4 - LUEC based on actual system load ranks the projects by unit energy cost as if the plants to be installed meet but do not exceed the system demand. System load growth is accounted for using the Operating Load Forecast Fall 2009 provided by Market Analysis in the System Planning department and extended through 2068. Table 5 - LUEC based on proposed plant capacity ranks the projects by unit energy cost if the plants were built to full potential, regardless of system load. Though cost values are significantly lower in Table 5 than Table 4, it is important to note that the energy in exceedance of the system load is essentially wasted.

Site Number	Nearest Town	Plant Capacity (MW)	Direct Project Cost ($ Millions)	Total Project Cost* ($ Millions)	2009 System Energy from Hydro Plant (GWh)	Maximum Possible Plant Output (GWh)	Nominal LUEC (¢/kWh in 2009$)
4	Mary's Harbour	0.450	2.60	**3.17**	**2.92**	**2.92**	8
MK S-1	**Makkovik**	**0.240**	**1.90**	**2.32**	**1.48**	**1.48**	**10**
5.b	**Charlottetown Port Hope Simpson and**	**1.46**	**22.40**	**28.45**	**9.55**	**9.55**	**12**
5.a	Charlottetown and Port Hope Simpson	1.46	13.00	**16.63**	**8.38**	**9.55**	13
1	Makkovik	0.660	6.90	**8.42**	**3.22**	**4.13**	14
5	Charlottetown	1.460	8.90	**11.38**	**5.31**	**9.55**	15
MH S-2A	Mary's Harbour	0.580	8.00	**9.76**	**3.80**	**3.80**	16
2	**Mary's Harbour**	**0.54**	**7.50**	**9.15**	**3.51**	**3.51**	**17**
MK S-2	Makkovik	0.220	3.30	**4.03**	**1.37**	**1.37**	18
MH S-4	**Mary's Harbour**	**0.24**	**4.00**	**4.88**	**1.60**	**1.60**	**19**
PHS S-1	Port Hope Simpson	0.090	1.70	**2.07**	**0.60**	**0.60**	21
CH S-3	Charlottetown	0.140	2.90	**3.54**	**0.94**	**0.94**	23
12	**Hopedale**	**0.53**	**10.10**	**12.32**	**3.21**	**3.21**	**24**
PHS S-3	**Port Hope Simpson**	**0.17**	**3.50**	**4.27**	**1.09**	**1.09**	**24**
PHS S-5	**Port Hope Simpson**	**0.150**	**3.20**	**3.90**	**0.95**	**0.95**	**25**
9.c	**Port Hope Simpson, Mary's Harbour, & Charlottetown**	**5.38**	**42.10**	**59.42**	**12.08**	**35.14**	**26**
3	**Port Hope Simpson**	**1.11**	**13.20**	**16.88**	**3.07**	**7.28**	**26**
6	Charlottetown	0.670	16.40	**20.01**	**4.35**	**4.35**	28
10	**Cartwright**	**2.00**	**17.70**	**21.63**	**4.15**	**13.00**	**29**
9.b	Port Hope Simpson & Charlottetown	5.380	34.80	**49.12**	**8.38**	**35.14**	31
CH S-1	Charlottetown	0.210	6.10	**7.13**	**1.37**	**1.37**	32
MK S-3	Makkovik	0.200	5.60	**6.83**	**1.28**	**1.28**	33
MH S-5	**Mary's Harbour**	**0.16**	**4.70**	**5.73**	**1.06**	**1.06**	**33**
PHS S-4	**Port Hope Simpson**	**0.09**	**3.40**	**4.15**	**0.62**	**0.62**	**36**
9.a	**Port Hope Simpson & Mary's Harbour**	**5.38**	**35.10**	**49.54**	**6.77**	**35.14**	**37**
CA S-1	Cartwright	0.070	2.20	**2.68**	**0.43**	**0.43**	38
8.c	Port Hope Simpson, Mary's Harbour, & Charlottetown	7.790	64.40	**90.90**	**12.08**	**50.87**	40
13	Nain	4.830	55.50	**67.84**	**7.04**	**26.37**	46
7	**Charlottetown**	**1.99**	**34.80**	**42.53**	**5.31**	**13.01**	**46**
CH S-5	Charlottetown	0.100	4.30	**5.25**	**0.68**	**0.68**	47
CH S-4	Charlottetown	0.070	3.20	**3.90**	**0.47**	**0.47**	50
8.b	**Port Hope Simpson & Charlottetown**	**7.79**	**57.30**	**80.88**	**8.38**	**50.87**	**50**
14	Nain	0.110	4.60	**5.61**	**0.59**	**0.59**	57
FH S-2	Mary's Harbour	0.100	5.00	**6.10**	**0.62**	**0.62**	59
PHS S-2	Port Hope Simpson	0.050	2.60	**3.17**	**0.32**	**0.32**	59
9	**Port Hope Simpson**	**5.38**	**27.70**	**39.10**	**3.07**	**35.14**	**60**
8.a	**Port Hope Simpson & Mary's Harbour**	**7.79**	**57.30**	**80.88**	**6.77**	**50.87**	**60**
11	**Hopedale**	**10.550**	**35.90**	**50.67**	**3.79**	**64.16**	**72**
FH S-1	Mary's Harbour	0.080	6.90	**8.42**	**0.54**	**0.54**	93
8	Port Hope Simpson	7.790	50.20	**70.86**	**3.07**	**50.87**	106
PHS S-6	Port Hope Simpson	0.060	1.70	**7.42**	**0.36**	**0.36**	122
CH S-2	Charlottetown	0.020	2.50	**3.05**	**0.13**	**0.13**	139
MH S-3	Mary's Harbour	0.010	1.70	**2.07**	**0.06**	**0.06**	204
MH S-6	Mary's Harbour	0.010	3.70	**4.51**	**0.06**	**0.06**	443

* Please note: The total capital costs have been calculated using the Nalcor Energy Project Proposal Form
** Please note: Forecasted system energy was calculated based on the Nalcor Energy 2009 Corporate Planning Assumptions.
This is the maximum amount of energy the diesel system could consume from the hydro plant. If value is less than 'Maximum possible plant output' this indicates that the hydro plant is not being fully utilized.

Table 4 - LUEC based on actual system load

Site Number	Nearest Town	Plant Capacity (MW)	Direct Project Cost ($ Millions)	Total Project Cost* ($ Millions)	Average Annual Energy (GWh)	Nominal LUEC (¢/kWh 2009$)
11	**Hopedale**	**10.55**	**35.90**	**50.67**	**64.16**	**5**
9	**Port Hope Simpson**	**5.38**	**27.70**	**39.10**	**35.14**	**7**
9.a	**Port Hope Simpson & Mary's Harbour**	**5.38**	**35.10**	**49.54**	**35.14**	**9**
9.b	**Port Hope Simpson & Charlottetown**	**5.38**	**34.80**	**49.12**	**35.14**	**9**
9.c	**Port Hope Simpson, Mary's Harbour, & Charlottetown**	**5.38**	**42.10**	**59.42**	**35.14**	**11**
4	**Mary's Harbour**	**0.450**	**2.60**	**3.17**	**2.920**	**8**
5	**Charlottetown**	**1.46**	**8.90**	**11.38**	**9.55**	**9**
5.a	**Charlottetown and Port Hope Simpson**	**1.46**	**13.00**	**16.63**	**9.55**	**17**
5.b	**Charlottetown, Port Hope Simpson, & Mary's Harbour**	**1.46**	**22.40**	**28.45**	**9.55**	**27**
8	**Port Hope Simpson**	**7.79**	**50.20**	**70.86**	**50.87**	**9**
8.a	**Port Hope Simpson & Mary's Harbour**	**7.79**	**57.30**	**80.88**	**50.87**	**14**
8.b	**Port Hope Simpson & Charlottetown**	**7.79**	**57.30**	**80.88**	**50.87**	**10**
8.c	**Port Hope Simpson, Mary's Harbour, & Charlottetown**	**7.79**	**64.40**	**90.90**	**50.87**	**16**
MK S-1	**Makkovik**	**0.240**	**1.90**	**2.32**	**1.480**	**10**
10	**Cartwright**	**2.00**	**17.70**	**21.63**	**13.00**	**16**
1	**Makkovik**	**0.660**	**6.90**	**8.42**	**4.13**	**13**
3	**Port Hope Simpson**	**1.11**	**13.20**	**16.88**	**7.28**	**16**
13	**Nain**	**4.83**	**55.50**	**67.84**	**26.37**	**17**
MH S-2A	Mary's Harbour	0.580	8.00	9.76	3.800	16
2	Mary's Harbour	0.540	7.50	9.15	3.510	17
MK S-2	Makkovik	0.220	3.30	4.03	1.370	18
MH S-4	Mary's Harbour	0.240	4.00	4.88	1.600	19
7	Charlottetown	1.99	34.80	42.53	13.01	21
PHS S-1	Port Hope Simpson	0.090	1.70	2.07	0.600	21
CH S-3	Charlottetown	0.140	2.90	3.54	0.940	23
12	Hopedale	0.530	10.10	12.32	3.210	24
PHS S-3	Port Hope Simpson	0.170	3.50	4.27	1.090	24
PHS S-5	Port Hope Simpson	0.150	3.20	3.90	0.950	25
6	Charlottetown	0.670	16.40	20.01	4.350	28
MK S-3	Makkovik	0.200	5.60	6.83	1.280	33
CH S-1	Charlottetown	0.210	6.10	7.13	1.370	32
MH S-5	Mary's Harbour	0.160	4.70	5.73	1.060	33
PHS S-6	Port Hope Simpson	0.060	1.70	7.42	0.360	122
CA S-1	Cartwright	0.070	2.20	2.68	0.430	38
PHS S-4	Port Hope Simpson	0.090	3.40	4.15	0.620	40
CH S-5	Charlottetown	0.100	4.30	5.25	0.680	47
CH S-4	Charlottetown	0.070	3.20	3.90	0.470	50
14	Nain	0.110	4.60	5.61	0.590	57
FH S-2	Mary's Harbour	0.100	5.00	6.10	0.620	59
PHS S-2	Port Hope Simpson	0.050	2.60	3.17	0.320	59
FH S-1	Mary's Harbour	0.080	6.90	8.42	0.540	93
CH S-2	Charlottetown	0.020	2.50	3.05	0.130	139
MH S-3	Mary's Harbour	0.010	1.70	2.07	0.060	204
MH S-6	Mary's Harbour	0.010	3.70	4.51	0.060	443
* Please note: The total project cost been escalated to include contingencies and interest during construction using the Nalcor Energy Project Proposal Form						

Table 5 - LUEC based on proposed plant capacity

Interconnection potential for hydro projects was also investigated. Due to the requirement for the interconnected towns to have fairly close proximity to one another for the option to remain economically viable, for the purposes of this study, this arrangement was only considered feasible for the communities of Charlottetown, Mary's Harbour, and Port Hope Simpson.

There were three possible sites large enough to consider for interconnection. Site 8, a 7.79 MW site approximately 11 km south of Port Hope Simpson, and Site 9, a 5.38 MW site approximately 13 km south of Port Hope Simpson, and Site 5, a 1.46 MW site approximately 12 km south of Charlottetown. The generation capacity of site 8 and site 9 are capable of supporting an interconnection between Port Hope Simpson and Mary's Harbour, Port Hope Simpson and Charlottetown, or all three communities. Site 5 is not considered capable of supporting the system load of all three communities, however a larger plant could be considered for this site. Table 6 provides site specific information on the additional cost associated with each of the interconnection opportunities. For further detailed information, please refer to Section 7 of Hatch's Review of Hydraulic Potential of Coastal Labrador.

Interconnection	Additional Overland Transmission (km)	Additional Submarine Transmission (km)	Additional Cost ($M)	System Load (GWh)	Project Cost		Maximum Possible Plant Output (GWh)	Nominal LUEC (¢/kWh)
					Without inter-connection ($M)	With inter-connection ($M)		
Site 8								
Mary's Harbour	35	0	7.1	6.77	50.2	57.3	50.9	60
Charlottetown	27	2	7.1	8.38	50.2	57.3	50.9	50
Mary's Harbour / Charlottetown	62	2	14.1	12.08	50.2	64.3	50.9	40
Site 9								
Mary's Harbour	37	0	7.4	6.77	27.7	35.2	35.1	37
Charlottetown	27	2	7.1	8.38	27.7	34.8	35.1	31
Mary's Harbour / Charlottetown	64	2	14.4	12.08	27.7	42.2	35.1	26
Site 5								
Port Hope Simpson	17.2	0.8	4.1	8.38	8.9	13.0	9.6	13
Port Hope Simpson/ Mary's Harbour	56.2	2.8	13.5	12.08	8.9	22.4	9.6	12

Table 6 – Summary of Site Interconnectivity Cost

5 SITE EVALUATION

The following site evaluations are based on the information collected from the site-specific weather stations and the developed HOMER models. More detailed results from these sources are available by location in the appropriate appendix. Though cost estimates are the basis for the comparison of systems, these costs are preliminary, and much more detailed work would be required to obtain more accurate cost information.

5.1 Nain

5.1.1 Energy Potential Analysis

Nain possesses a good wind resource. The discrepancies between the data available from the diesel plant station and the two local Environment Canada stations is the result of poor siting of the diesel plant weather station anemometer. Looking at the average wind speed trends in Nain, it is readily apparent that though wind speeds are somewhat lower in the summer months, they increase steadily throughout the fall and into the winter. This is an excellent fit with Nain's winter peaking energy requirements. Based on the wind duration curves available for the fall months, wind speeds measured at the diesel plant are in exceedance of 5m/s approximately 30% of the time. As it has been determined that the diesel plant weather station is not optimally sited, it is reasonable to assume that the percentage of time with wind speeds greater than the 5 m/s threshold is in fact higher. Based on daily check of the weather station communications feed, the anemometer has frozen several times during December. This suggests that any wind installations in Nain would have to be arctic grade as icing will surely be a factor, as with all sites on the Labrador Coast. For data plots for Nain, please refer to Appendix A.

Site 13 is one identified economically feasible hydro site capable of serving Nain. Its cost of energy is lower than both that of diesel generation and the predicted cost of a wind diesel hybrid system. It is advised that further analysis of site 13 be performed to ascertain its true hydro potential.

Nain possesses a moderate solar resource in late spring and throughout summer, but extremely short days mean its solar resource is poor in winter months. This does not suggest a good fit for solar energy with the system's winter peaking nature.

5.1.2 Economic Analysis

Based on simulation results, using current estimates of wind, hydro and solar potential, Nain could easily use wind turbine to supply 30% of its required system load. As forecasted system growth occurs and diesel fuel prices rise, the percentage of load that could be supplied by wind energy increases slightly to 31% with the addition of an extra turbine. There is an immediate financial benefit to using wind energy in comparison with diesel fuel prices, and this benefit increases as fuel prices rise.

5.2 Hopedale

5.2.1 Energy Potential Analysis

There is a reasonable amount of potential in wind energy in Hopedale. Wind speed measurements obtained from the diesel plant weather station provide lower monthly averages than those of the local Environment Canada weather station. Looking at the monthly wind speed plots, it is evident that on average the diesel plant is seeing lower winds on a daily basis; however the general behaviour of the wind is the same in both locations. The similarity in the shape of the wind speed curves but discrepancy in measured speeds suggests that the weather station at the diesel plant is not optimally sited and better wind potential exists than that indicated by the diesel plant weather station. For data plots for Hopedale, please refer to Appendix B.

One economically viable hydro plant was identified for Hopedale. Site 12 could potentially supply the community with 3.21 GWh annually at a cost of energy 2-3 ¢/kWh less expensive than diesel generation.

Hopedale has one of the smaller solar resources examined in the study based on available data. Though moderate solar potential is available in the few summer months, the majority of months do not exhibit this potential.

5.2.2 Economic Analysis

The simulation of wind turbines in the Hopedale system provides the largest savings through use of wind energy over diesel fuel in the study. Based on the 2011 forecasted system load, turbines could be used to supply 43% of the community's energy requirements. As the system load and fuel prices increase, an additional turbine could be integrated to increase the system load met by wind energy to 47%. In addition, as these increases in costs are encountered, the margin in savings over diesel fuel increases as well, making wind energy even more economically beneficial.

5.3 Makkovik

5.3.1 Energy Potential Analysis

In terms of wind energy, Makkovik has more wind potential than the diesel plant weather station would suggest. Environment Canada has a much better situated weather station in Makkovik that consistently records higher wind speeds than those recorded at the diesel plant with discrepancies between the two sources reaching as high as 10 m/s. This suggests that the weather station at the diesel plant is not optimally sited for wind speed measurement. The full potential of Makkovik is still not understood as the Environment Canada station only records data for eight hours per day. Based on the available data Makkovik has an excellent wind resource, with average speeds estimated in exceedance of 10m/s throughout autumn. For data plots for Makkovik, please refer to Appendix C.

In addition, Makkovik has excellent hydro resources that can provide extremely cheap electricity in comparison to diesel fuel generated electricity. Sites MK S-1, 1 and MK S-2 all offer unit energy costs below the current price of diesel fuel. If storage solutions were considered, Site 1 could be capable of completely displacing the Makkovik diesel plant. Sites MK S-1 and MK S-2, while too small to displace the diesel plant do offer inexpensive energy compared to diesel generation.

In comparison with the promise offered by the other alternative energies, solar is thought to have the least potential for a viable solution for Makkovik.

5.3.2 Economic Analysis

Makkovik has a choice of viable alternative energy solutions: both wind and hydro offer financially attractive options. With respect to wind energy, Makkovik could potentially integrate multiple wind turbines. Based on the 2011 load forecast, the turbines could supply the system with 35% of its required energy. As fuel prices and system load increase, the model suggests that no additional wind turbines be added to the system. Consequently, the proportion of wind energy supplied to the system remains constant.

Hydro generation appears to be an economically attractive option for Makkovik. The unit energy costs of Sites MK S-1, 1, and MK S-2 are lower than the current costs of diesel energy, and the cost of energy from the hybrid system noted above. As the price of diesel rises, these hydro options become increasingly attractive. Site 1 could possibly replace the Makkovik diesel plant, but will require the inclusion of the cost of reservoir storage as part of the project.

5.4 Cartwright

5.4.1 Energy Potential Analysis

In Cartwright, wind energy holds the highest promise in terms of alternative energies. Examining the data collected by the diesel plant weather station, it is evident that the during summer periods, the wind speeds in Cartwright are smaller than those experienced during winter months. As illustrated in the wind duration curves, the amount of time with winds in excess of 5 m/s is at its lowest in July and increases steadily throughout the remaining months of the year. For data plots for Cartwright, please refer to Appendix D.

The close correlation of daily wind speeds between the measured data with that of the Cartwright Environment Canada weather station increases the confidence in the measurements obtained at the Cartwright diesel plant. Looking at the plots in Appendix D, it is easy to verify that the same peak speeds and periods of low winds are encountered at both sites, with slightly higher measurements recorded at the Environment Canada location. This suggests the placement of the weather station at the Cartwright diesel plant is not indicative of the highest wind speeds in the area. To ensure the wind energy potential in Cartwright is accurately understood, it is advised that additional measurements be obtained by deploying a met tower in a location optimally sited for a wind farm.

Though hydro sites have been identified for Cartwright, the high cost of energy associated with these plants does not make hydro an economically feasible option.

In terms of solar energy, Cartwright possesses a moderate solar resource. However, in comparison to the same system served with wind energy, solar remains a more expensive option. This summer peaking alternative energy coincides nicely with Cartwright's load profile.

5.4.2 Economic Analysis

During modeling, the addition of wind turbines resulted in an extremely small decline in the cost of energy. This makes the integration a financially neutral choice when compared to the continued operating cost of the Cartwright diesel plant. In HOMER simulation, the wind turbines were capable of supplying 12% of the community load. In addition, the excess electricity produced by the system was approximately 0%, meaning no wind energy was wasted in simulation.

As system load and diesel fuel prices are increased in the model, an additional turbine is suggested and the margin between the cost of energy of the hybrid grid versus the diesel plant widens slightly. This increase remains well below 1¢/kWh, however. Therefore, even as the system grows and fuel becomes more expensive, there is no forecasted significant financial benefit in moving to a hybrid system. Such a project is considered viable for environmental reasons.

5.5 Charlottetown

5.5.1 Energy Potential Analysis

Measured wind speeds in Charlottetown are among the lowest of those obtained in the study. Analysis of the Charlottetown data suggests that though there are some periods of prolonged high wind speeds, lower wind speeds tend to dominate during the months for which data is available. For data plots for Charlottetown, please refer to Appendix E.

In this case, there is no Environment Canada station in Charlottetown to compare the collected data with. As such, there is only six months of collected data available for Charlottetown at this point, meaning that its wind energy potential is not fully understood at this point. It is advised to continue monitoring the wind speeds in Charlottetown and revisit the analysis once one complete year of data is available.

Hydro options exist for Charlottetown both in terms of shared interconnections with Mary's Harbour and/or Port Hope Simpson and plants that would serve Charlottetown alone. The interconnection options are discussed in Section 5.8 Interconnection Possibilities. Sites 5 and CH S-3 both offer costs of energy lower than those of diesel generation.

In terms of solar energy, Charlottetown presents a moderate solar resource, peaking in July. This summer peak fits well with the Charlottetown load profile.

5.5.2 Economic Analysis

Based on simulation results, with the current estimates of wind, solar, and hydraulic potential, there are no economic benefits in integrating renewable energies into the Charlottetown system. The integration of a wind turbine is the most economic renewable option, however this option remains slightly more expensive than the continued operation of the diesel plant. As the system grows and the price of fuel increases, the diesel plant remains the most economical option.

Charlottetown could possibly benefit from interconnection to a larger hydro plant, shared with Port Hope Simpson and/or Mary's Harbour. The results of this hydraulic analysis are found in Section 5.8 Interconnection Possibilities.

5.6 Port Hope Simpson

5.6.1 Energy Potential Analysis

Port Hope Simpson has one of the lower wind resources identified in the study. With low monthly averages from June through November it is thought that wind energy is not the best match for Port Hope Simpson in terms of alternative energies. For data plots for Port Hope Simpson, please refer to Appendix F.

Hydro offers promising options for Port Hope Simpson on its own or as an interconnection with Charlottetown and/or Mary's Harbour. The interconnection possibilities are examined in Section 5.8 Interconnection Possibilities. Though the proximity of site 9 and site 8 to Port Hope Simpson makes it possible for them to serve Port Hope Simpson alone, the plants are far too large for the needs of the community and the associated cost of energy would be too high. Sites 3 and PHS S-1 offer attractive alternatives for hydro plants that would serve only Port Hope Simpson. Both have costs of energy less expensive than that of diesel fuel generation.

Though solar resources are moderate in the area, when compared to the hydro potential, they are more expensive, less efficient and technically challenging.

5.6.2 Economic Analysis

Diesel energy remains less expensive than hybrid installations with solar or wind energy. In analysis of the modeling results, Port Hope Simpson could potentially integrate one wind turbine at a slightly higher cost compared to diesel fuel. As the system load increases, the number of suggested turbines remains constant at one. In addition, the percentage of system load supplied by the wind turbine is 5% in both cases. This suggests that the wind resource in Port Hope Simpson is not the most economic alternative energy solution and has little potential for growth as the towns energy requirements increase. It is worth nothing, however, that Port Hope Simpson is located in a valley surrounded by hills. Wind resources may be good at the hill tops, but these resources have not been assessed.

As reflected in both Table 4 - LUEC based on actual system load and Table 5 - LUEC based on proposed plant capacity, site 8 exists as a Hydro option that could supplement the community energy supply with clean, renewable energy at a considerable savings over diesel fuel.

5.7 Mary's Harbour

5.7.1 Energy Potential Analysis

Based on measured data, average wind speeds in Mary's Harbour would classify the resource as having small wind potential. Mary's Harbour has three sources of wind speed data; the diesel plant station, and two local Environment Canada stations. All data sets in a given monthly wind plot have the same shape and roughly the same peak values. Discrepancies in measurement results from the time interval between measurements; the diesel plant provides data values at ten minute intervals, whereas one Environment Canada station samples every hour and the other once per hour for eight hours per day. In this case, for the months where data from the diesel plant is available, it is thought that this data provides the most accurate picture of the wind behaviour in Mary's Harbour. Based on the wind duration curves for June through August, the available wind potential in Mary's Harbour is not high enough for turbines to support a large percent of the load. However, an increase in wind speed is evident throughout

October and November and it is expected that this increase would continue through the rest of winter. Therefore, it is advised to continue monitoring the wind speeds in Mary's Harbour using the current diesel plant weather station. For data plots for Mary's Harbour, please refer to Appendix G.

Potential hydro sites have been identified for Mary's Harbour, both in terms of interconnection possibilities and sites that would serve Mary's Harbour alone. Interconnection opportunities are discussed in Section 5.8 Interconnection Possibilities. With respect to sites identified to serve Mary's Harbour alone, Site 4 was identified as a good potential site as well as Sites MH S-2A and MH S-4. These sites indicate energy prices lower than that of diesel fuel, but have a higher energy cost than Site 4. All three sites merit further consideration for possible development.

Mary's Harbour does have moderate solar potential which would fit nicely with its summer peaking load shape. Should solar technology become more efficient and less expensive, it should be reconsidered as an option for Mary's Harbour.

5.7.2 Economic Analysis

Diesel energy remains less expensive than hybrid installations with solar or wind energy. In analysis of the modeling results, Mary's Harbour could potentially integrate one wind turbine at a slightly higher cost compared to diesel fuel. However as system load increases and fuel prices rise, the number of suggested turbines remains constant at one turbine. In addition, the percentage of the system load served by wind remains constant at five percent. This suggests that wind energy is not the most suitable fit for Mary's Harbour.

As reflected in both Table 4 - LUEC based on actual system load and Table 5 - LUEC based on proposed plant capacity, Hydro options exist that could supplement the community energy supply with clean, renewable energy at a considerable savings over diesel fuel.

5.8 Interconnection Possibilities

Interconnection possibilities exist at Sites 5, 8, and 9. As discussed in Section 4.3 Hydraulic Potential, both site 8 and site 9 have average annual energies that could support the load of Charlottetown, Port Hope Simpson and Mary's Harbour. If further analysis was conducted and storage solutions were explored, either of these plants could potentially replace all three community diesel plants. In the unit energy cost analysis performed, the extra costs associated with interconnection did not increase the unit energy cost by a significant amount. All interconnection possibilities (i.e. Site 8 to Port Hope Simpson and Mary's Harbour and/or Charlottetown, Site 9 to Port Hope Simpson and Mary's Harbour and/or Charlottetown) remain economically favourable when compared to the price of diesel fuel (estimated at an average cost of 25¢/kWh across the three communities). The estimated cost of energy for the interconnection sites are reflected in Table 4 - LUEC based on actual system load and Table 5 - LUEC based on proposed plant capacity.

Site 5 differs from the other sites identified for interconnection as, based on proposed capacity; it can only sustain the load of two out of three communities; Charlottetown and Port Hope Simpson or Mary's Harbour. The estimated cost of energy remains low for an interconnection to either town. In addition, the proposed plant size could possibly be increased to accommodate an interconnection to the third town.

6 CONCLUSIONS AND RECOMMENDATIONS

6.1 Conclusions

Based on the existing weather data, it is reasonable to confirm that Labrador possesses alternative energy resources that, under the right economic conditions, could be developed to reduce the usage of diesel generation in many communities. In general, the most promising potential lies with wind and hydro power.

The wind data collected indicates that reasonable amounts of resource potential exist in Nain, Hopedale, Makkovik, and Cartwright. Based on the load profiles for each of these communities, the best fits for wind energy are in Nain, Hopedale, and Makkovik.

The solar data collected indicates that resource potential exists across Labrador, however due to the extremely high cost of solar energy and its relative energy conversion inefficiency solar energy is not recommended for further consideration at this time.

Hatch's Review of Hydraulic Potential of Coastal Labrador identified numerous potential sites with estimated cost of energy less than that of diesel generation. In addition, some opportunities were identified that possessed sufficient energy at low cost to completely replace one or more diesel plants. With the identified opportunity for the interconnection of Charlottetown, Port Hope Simpson, and Mary's Harbour it is possible that three plants could be eliminated, making a larger plant more viable.

6.2 Recommendations

Based on the detailed analysis of all data, the following actions are recommended.

- Nain, Hopedale, Makkovik, and Cartwright should have wind energy prefeasibility investigations conducted. This would include a thorough wind farm site selection process and collection of hub height data for analysis (minimum one year).

- Prefeasibility hydro investigations should be conducted at hydro sites that have potentially low energy costs relative to energy produced from burning diesel fuel, as well as those sites that are potentially low cost energy relative to energy from a diesel plant and are large enough to completely replace one or more diesel plants. The list below identifies the sites with a low energy cost relative to diesel fuel:
    - Site 4
    - Site MK S-1
    - Site 1
    - Site 5
    - Site MH S-2A
    - Site 2
    - Site MK S-2
    - Site MH S-4
    - Site PHS S-1
    - Site CH S-3
    - Site 12
    - Site PHS S-3
    - Site PHS S-5

- There is little high resolution mapping available for Labrador. This limits the accuracy of the resource assessment. More detailed mapping should be produced to further delineate the wind and hydro sites. This could be accomplished through a LIDAR Survey covering the sites identified in the study, and could be extended to the whole coast. Such data could potentially yield a greater number of sites, and provide the data necessary to move forward with investigations.

- The diesel plant weather stations should continue to be monitored and recorded on an ongoing basis to collect as much information as possible. In sites where a discrepancy exists between diesel plant data and Environment Canada data, investigations begin into moving the weather station to a more optimally sited location. These sites include:
  - Cartwright
  - Hopedale
  - Makkovik
  - Nain
  - Mary’s Harbour

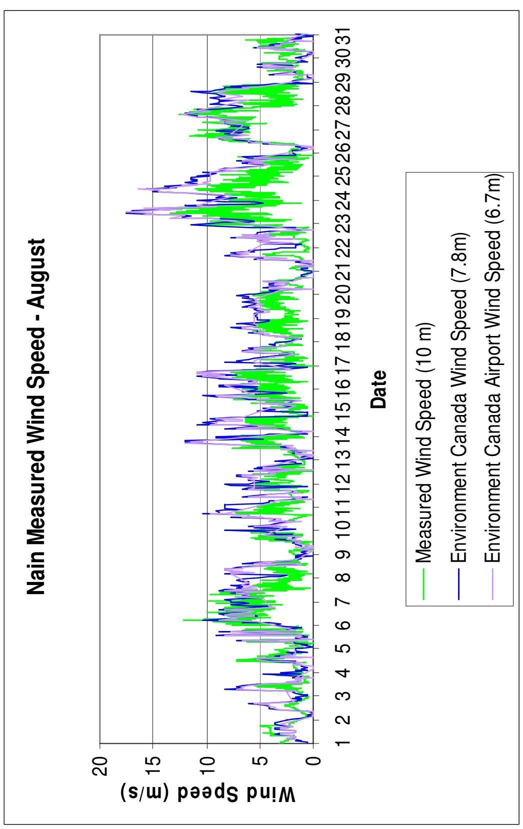
7 REFERENCES

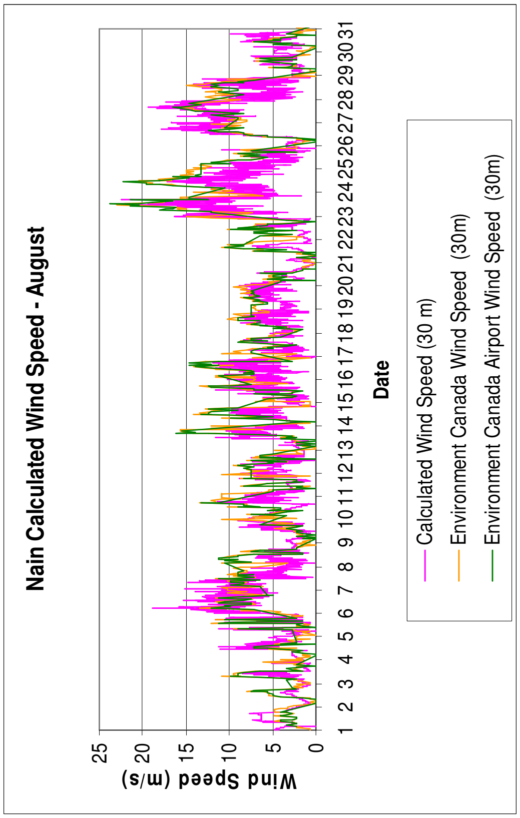
1. Population by Census Subdivision Newfoundland and Labrador 2006 Census Updated March 13, 2007. Newfoundland and Labrador Statistics Agency. Visited December 23, 2009. http://www.stats.gov.nl.ca/Statistics/Census2006/PDF/POP_CSD_Alphabetical_2006.pdf

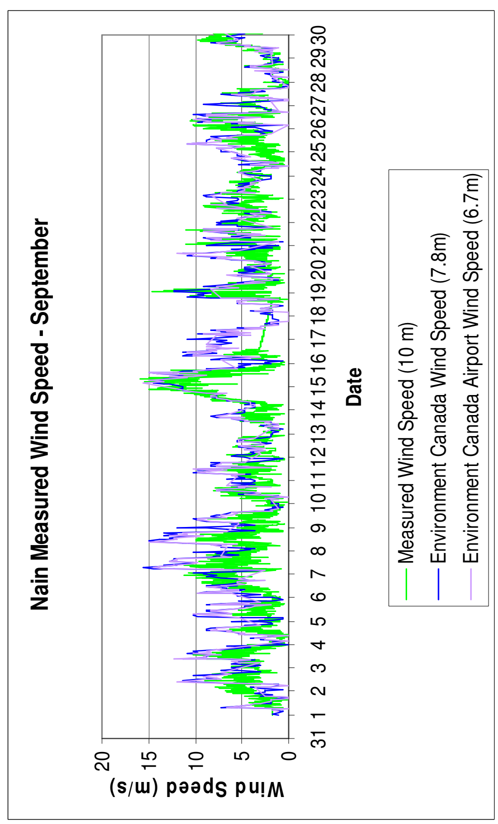
2. Canadian Wind Energy Atlas Updated August 21, 2008. Visited December 23, 2009. http://www.windatlas.ca/en/methodology.php

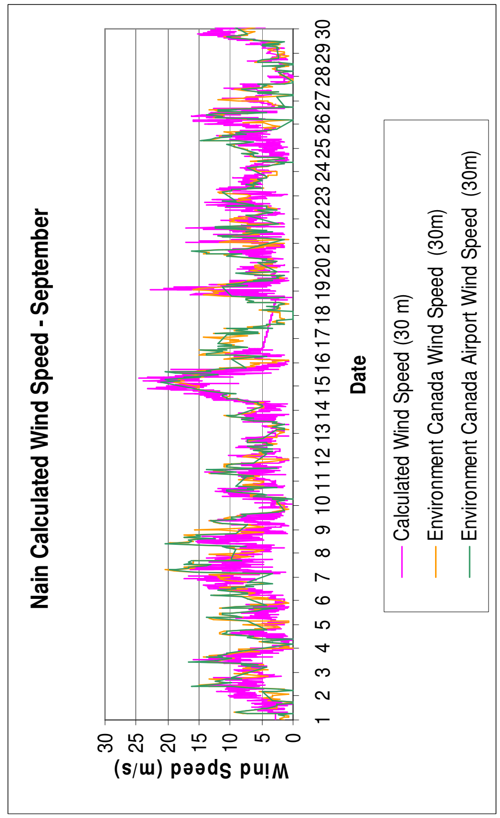
3. Surface Meteorology and Solar Energy Updated December 23, 2009. Atmospheric Science Data Center. Visited December 23, 2009. http://eosweb.larc.nasa.gov/cgi-bin/sse/sse.cgi?+s01

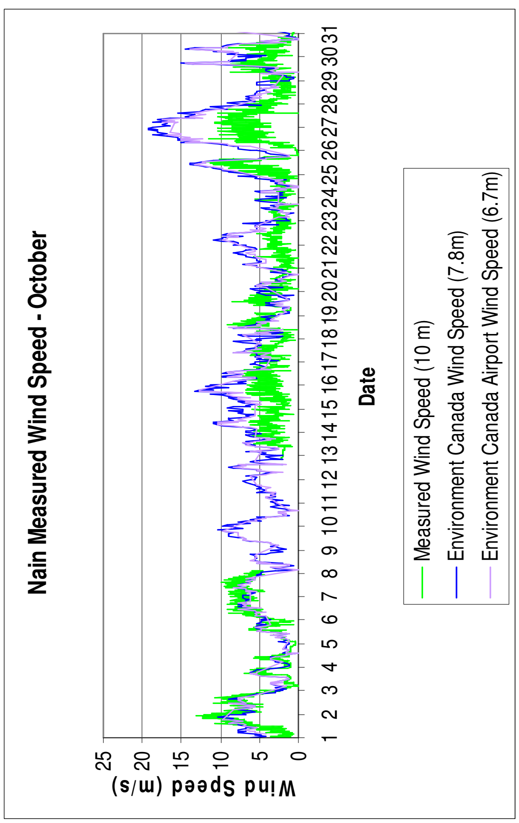
APPENDIX A - NAIN

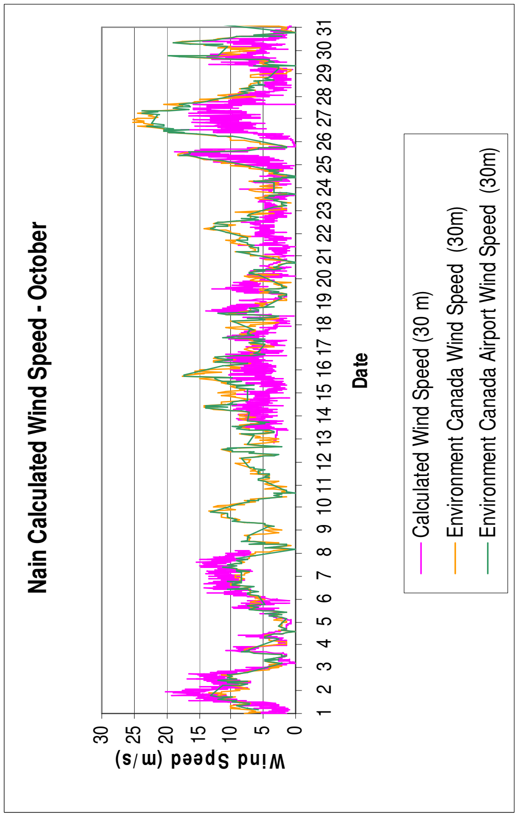

Nain Measured Wind Speed - August
Wind Speed (m/s)
Date
Measured Wind Speed (10 m)
Environment Canada Wind Speed (7.8m)
Environment Canada Airport Wind Speed (6.7m)

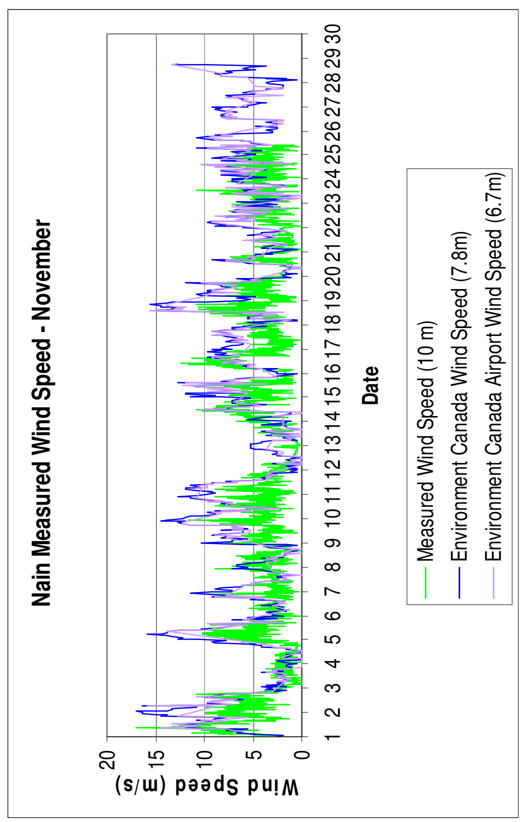

Nain Calculated Wind Speed - August
Wind Speed (m/s)
Date
Calculated Wind Speed (30 m)
Environment Canada Wind Speed (30m)
Environment Canada Airport Wind Speed (30m)

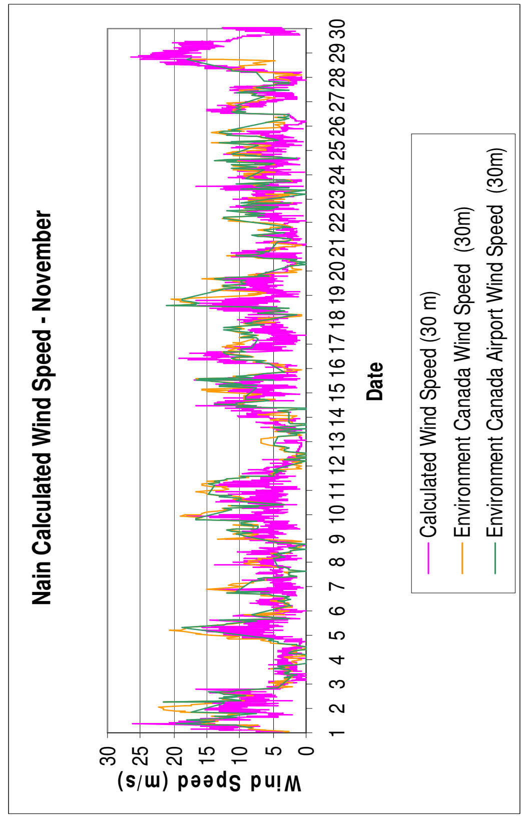

Nain Measured Wind Speed - September
Wind Speed (m/s)
Date
Measured Wind Speed (10 m)
Environment Canada Wind Speed (7.8m)
Environment Canada Airport Wind Speed (6.7m)

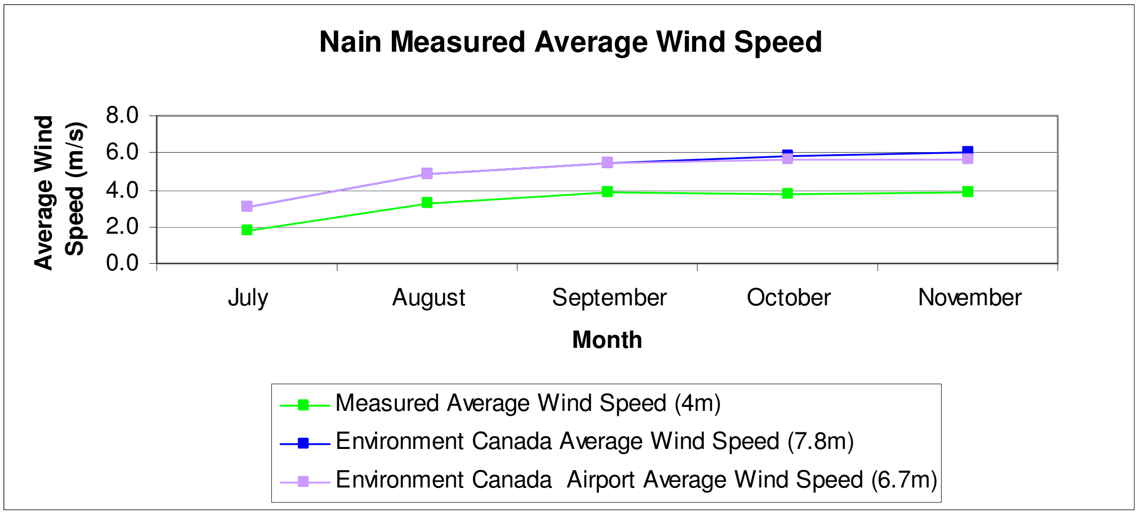

Nain Calculated Wind Speed - September
Wind Speed (m/s)
Date
Calculated Wind Speed (30 m)
Environment Canada Wind Speed (30m)
Environment Canada Airport Wind Speed (30m)

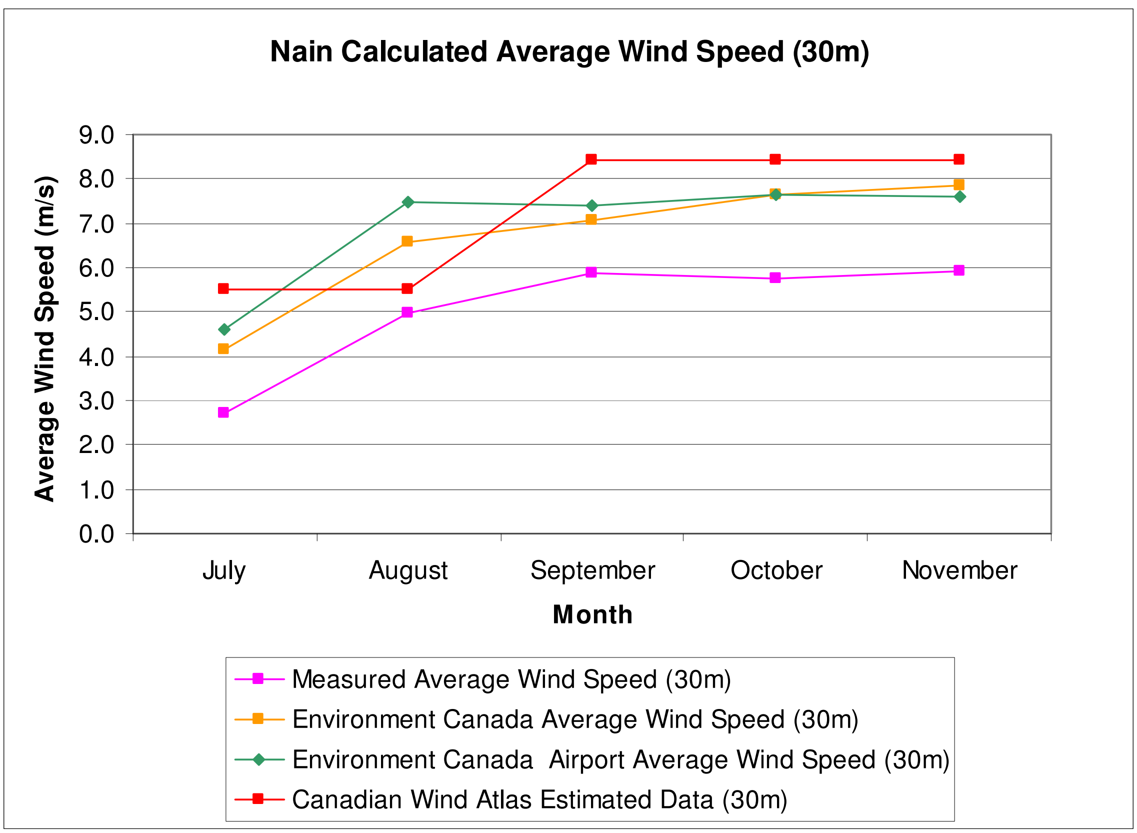

Nain Measured Wind Speed - October
Wind Speed (m/s)
Date
Measured Wind Speed (10 m)
Environment Canada Wind Speed (7.8m)
Environment Canada Airport Wind Speed (6.7m)

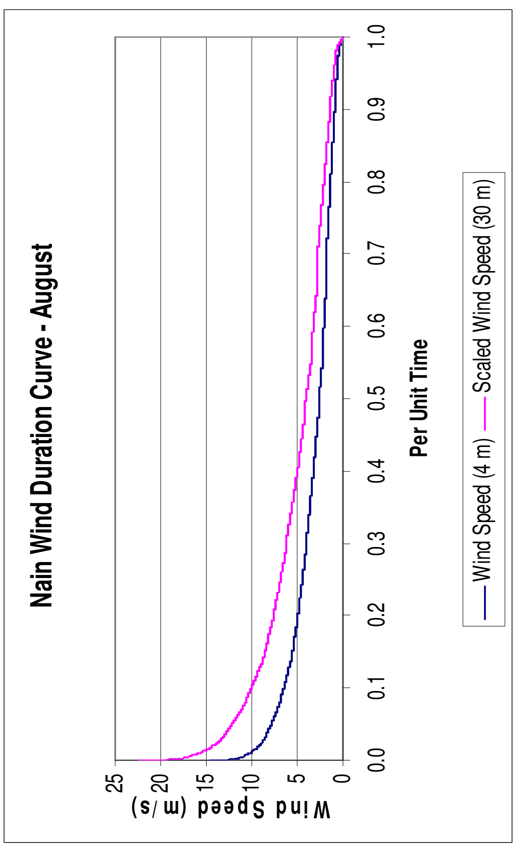

Nain Calculated Wind Speed - October
Wind Speed (m/s)
Date
Calculated Wind Speed (30 m)
Environment Canada Wind Speed (30m)
Environment Canada Airport Wind Speed (30m)

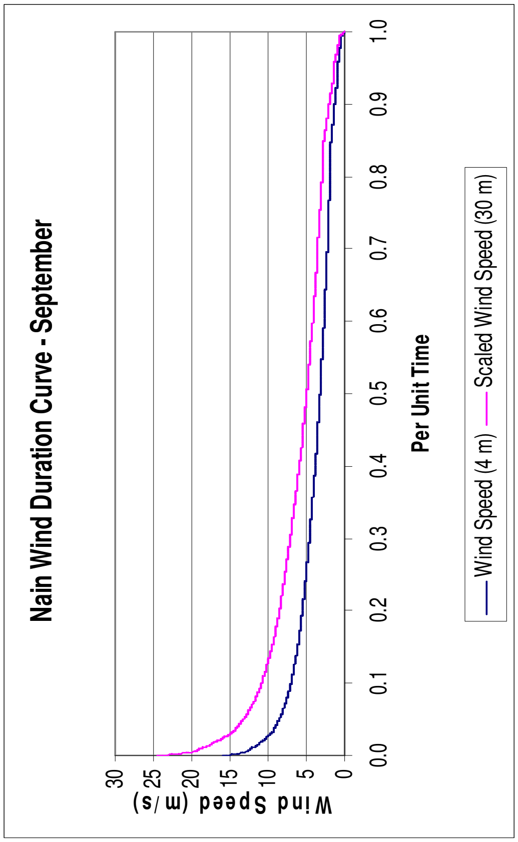

Nain Measured Wind Speed - November
Wind Speed (m/s)
Date
Measured Wind Speed (10 m)
Environment Canada Wind Speed (7.8m)
Environment Canada Airport Wind Speed (6.7m)

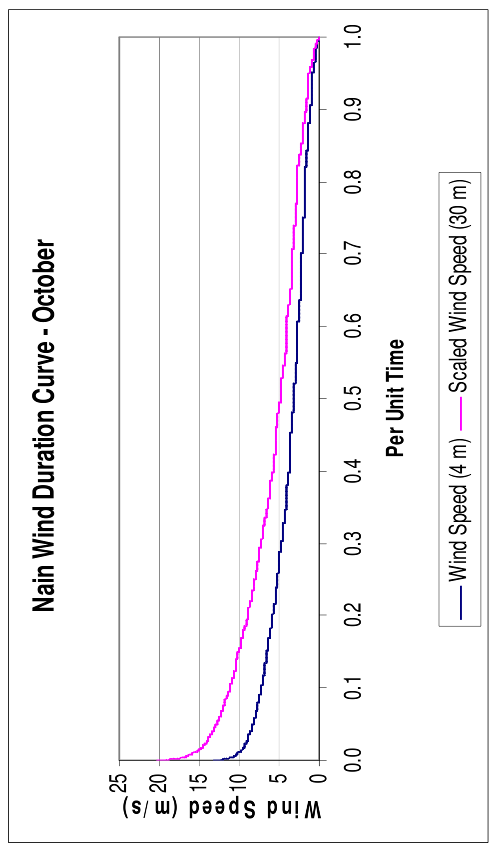

Nain Calculated Wind Speed - November
Wind Speed (m/s)
Date
Calculated Wind Speed (30 m)
Environment Canada Wind Speed (30m)
Environment Canada Airport Wind Speed (30m)

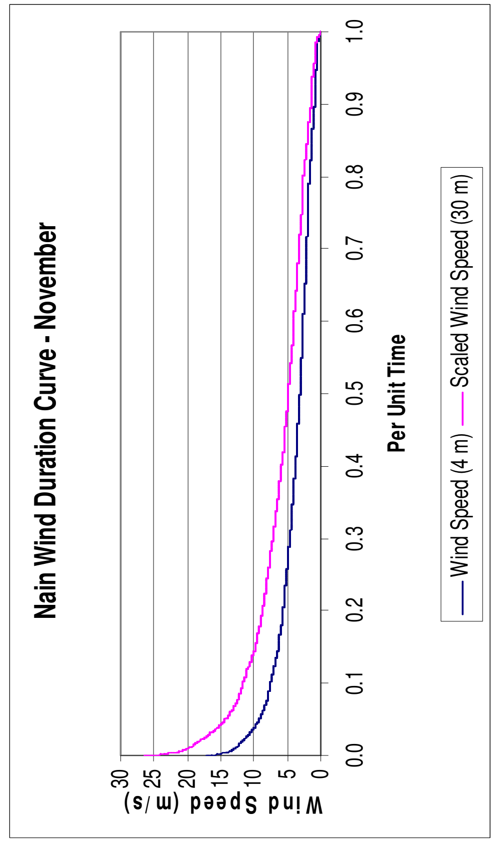

Nain Measured Average Wind Speed
Average Wind Speed (m/s)
8.0
6.0
4.0
2.0
0.0
July
August
September
October
November
Month
Measured Average Wind Speed (4m)
Environment Canada Average Wind Speed (7.8m)
Environment Canada Airport Average Wind Speed (6.7m)

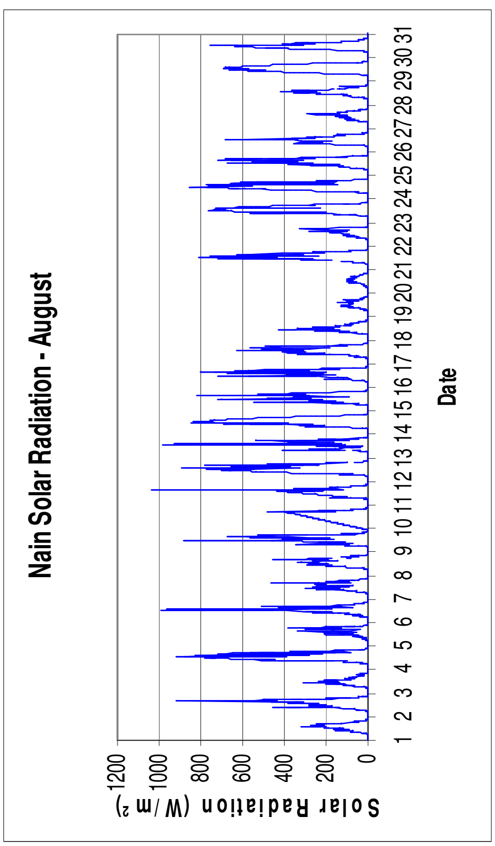

Nain Calculated Average Wind Speed (30m)
Average Wind Speed (m/s)
9.0
8.0
7.0
6.0
5.0
4.0
3.0
2.0
1.0
0.0
July
August
September
October
November
Month
Measured Average Wind Speed (30m)
Environment Canada Average Wind Speed (30m)
Environment Canada Airport Average Wind Speed (30m)
Canadian Wind Atlas Estimated Data (30m)

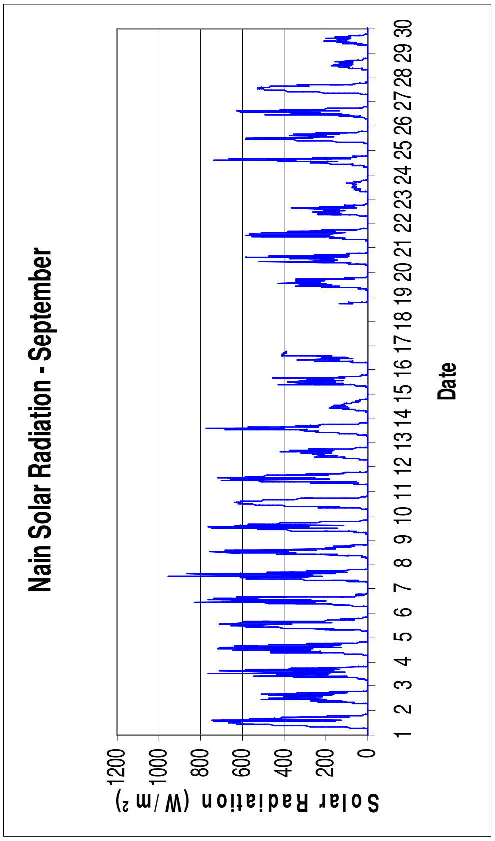

Nain Wind Duration Curve - August
Wind Speed (m/s)
25
20
15
10
5
0
0.0
0.1
0.2
0.3
0.4
0.5
0.6
0.7
0.8
0.9
1.0
Per Unit Time
Wind Speed (4 m)
Scaled Wind Speed (30 m)

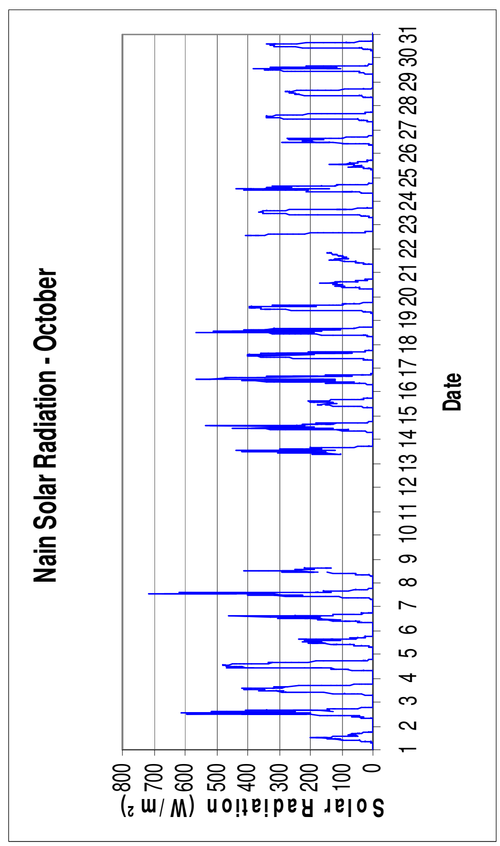

Nain Wind Duration Curve - September
Wind Speed (m/s)
30
25
20
15
10
5
0
0.0
0.1
0.2
0.3
0.4
0.5
0.6
0.7
0.8
0.9
1.0
Per Unit Time
Wind Speed (4 m)
Scaled Wind Speed (30 m)

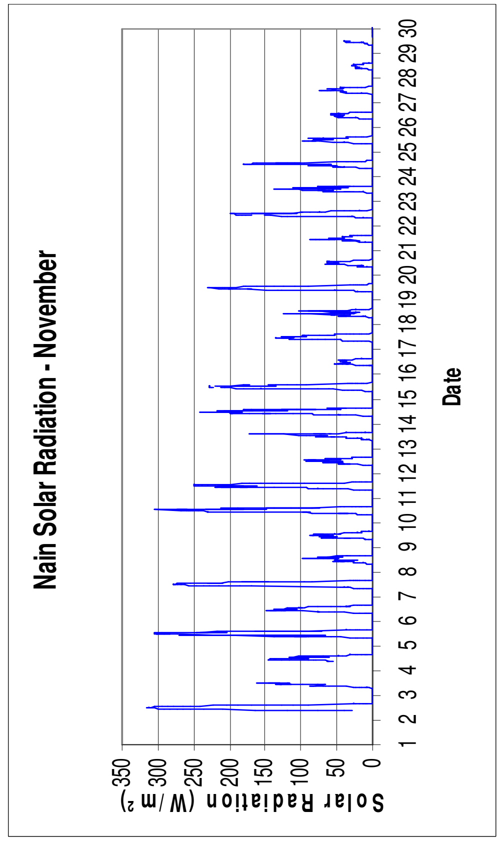

Nain Wind Duration Curve - October
Wind Speed (m/s)
25
20
15
10
5
0
0.0
0.1
0.2
0.3
0.4
0.5
0.6
0.7
0.8
0.9
1.0
Per Unit Time
Wind Speed (4 m)
Scaled Wind Speed (30 m)

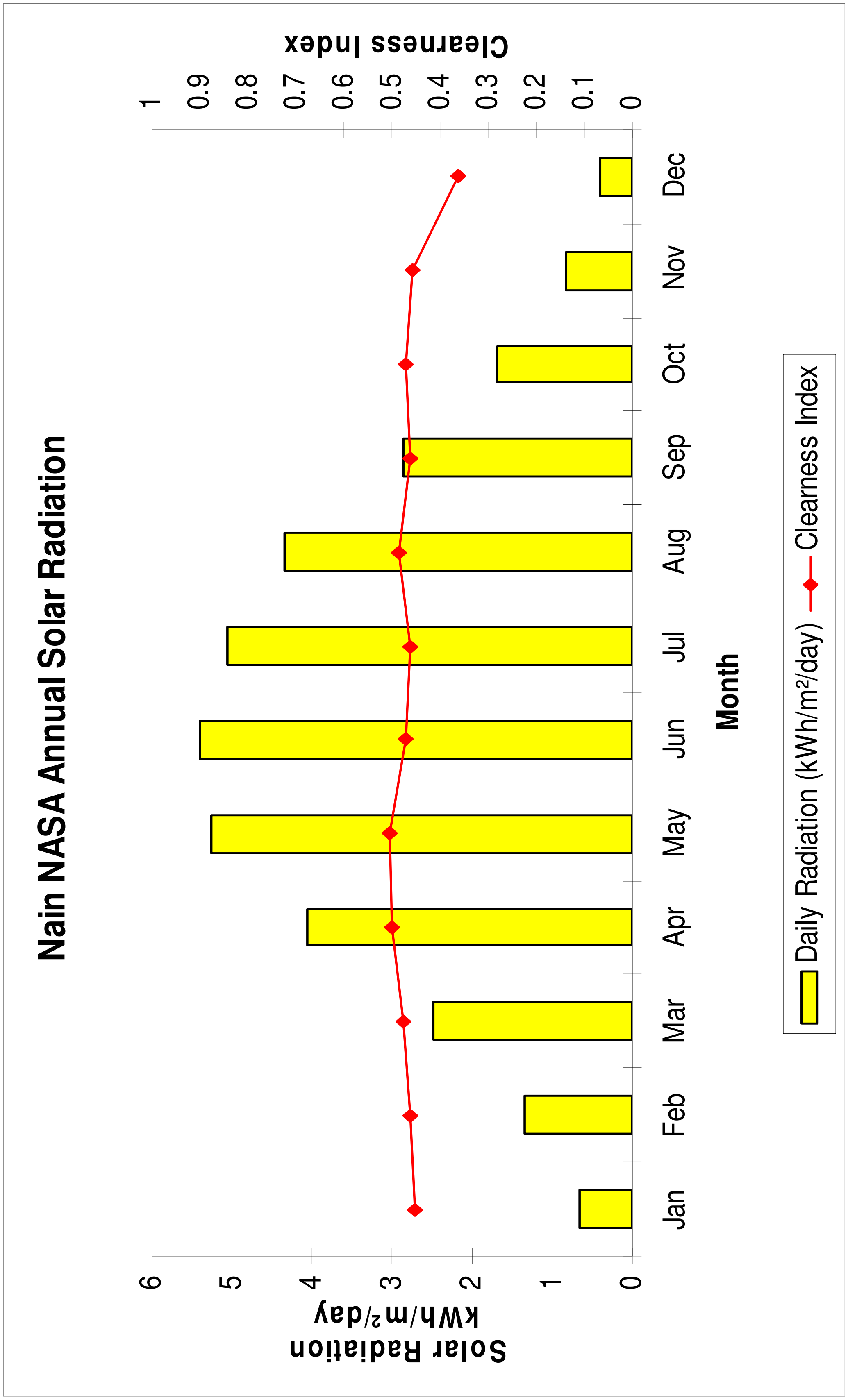

Nain Wind Duration Curve - November
Wind Speed (m/s)
30
25
20
15
10
5
0
0.0
0.1
0.2
0.3
0.4
0.5
0.6
0.7
0.8
0.9
1.0
Per Unit Time
Wind Speed (4 m)
Scaled Wind Speed (30 m)

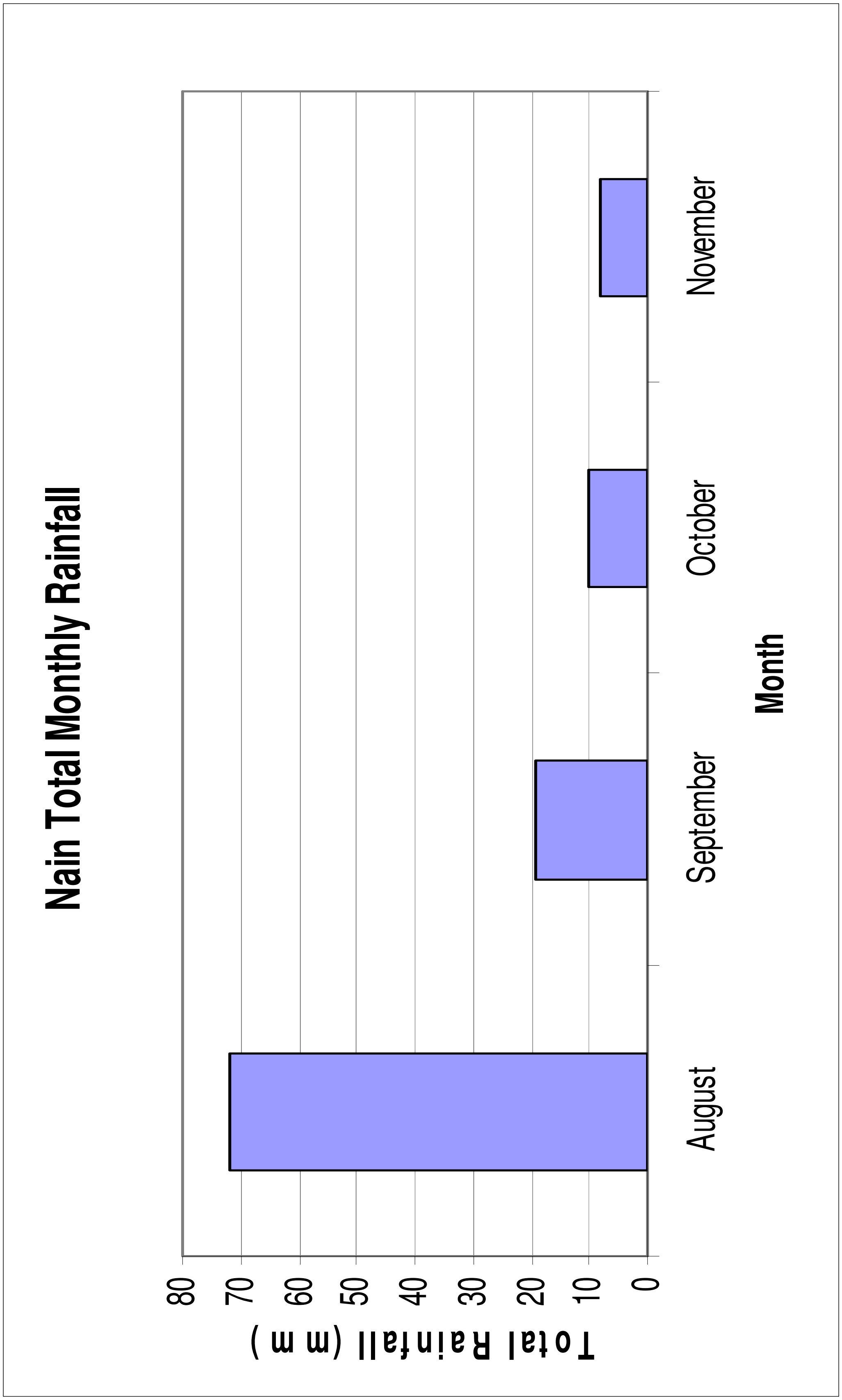

Nain Solar Radiation - August
Solar Radiation (W/m²)
Date


Nain Solar Radiation - September
Solar Radiation (W/m²)
Date


Nain Solar Radiation - October
Solar Radiation (W/m²)
Date


Nain Solar Radiation - November
Solar Radiation (W/m²)
Date


Nain NASA Annual Solar Radiation
Solar Radiation kWh/m²/day
0
1
2
3
4
5
6
Clearness Index
0
0.1
0.2
0.3
0.4
0.5
0.6
0.7
0.8
0.9
1
Jan
Feb
Mar
Apr
May
Jun
Jul
Aug
Sep
Oct
Nov
Dec
Month
Daily Radiation (kWh/m²/day)
Clearness Index

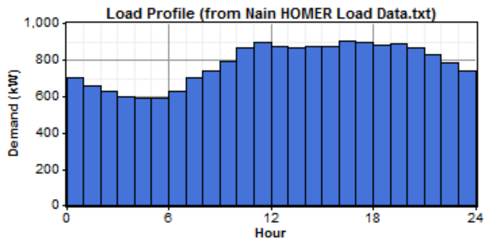

Nain Total Monthly Rainfall
Total Rainfall (mm)
80
70
60
50
40
30
20
10
0
August
September
October
November
Month

HOMER Input Summary

File name: Nain.hmr
File version: 2.67 beta
Author:

AC Load: Nain Net System Load

Data source:	Nain HOMER Load Data.txt
Daily noise:	8.91%
Hourly noise:	8.19%
Scaled annual average:	21,000, 21,414, 21,830, 22,247, 22,668 kWh/d
Scaled peak load:	1,699, 1,733, 1,766, 1,800, 1,834 kW
Load factor:	0.515



PV

Size (kW)	Capital ($)	Replacement ($)	O&M ($/yr)
50.000	400,000	400,000	10,000
100.000	750,000	750,000	15,000

Sizes to consider:	0, 50, 100 kW
Lifetime:	20 yr
Derating factor:	80%
Tracking system:	No Tracking
Slope:	56.5 deg
Azimuth:	0 deg
Ground reflectance:	20%

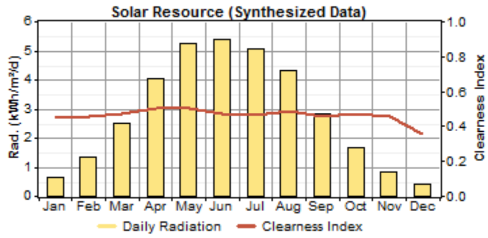
Solar Resource

Latitude: 56 degrees 32 minutes North
Longitude: 61 degrees 41 minutes West
Time zone: GMT -4:00

Data source: Synthetic

Month	Clearness Index	Average Radiation (kWh/m^2/day)
Jan	0.451	0.670
Feb	0.460	1.330
Mar	0.474	2.490
Apr	0.502	4.050
May	0.507	5.260
Jun	0.472	5.400
Jul	0.464	5.050
Aug	0.486	4.330
Sep	0.460	2.850
Oct	0.470	1.680
Nov	0.459	0.820
Dec	0.360	0.400

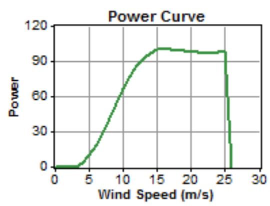
Scaled annual average: 2.86 kWh/m²/d



AC Wind Turbine: Northern Power NW100/21

Quantity	Capital ($)	Replacement ($)	O&M ($/yr)
1	500,000	400,000	10,000

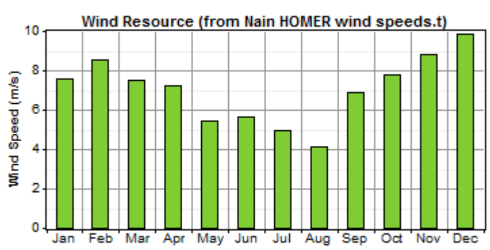
Quantities to consider:	0, 1, 2, 3, 4, 5, 6, 7, 8, 9, 10
Lifetime:	20 yr
Hub height:	37 m



Wind Resource

Data source: Nain HOMER wind speeds.txt

Month	Wind Speed (m/s)
Jan	7.58
Feb	8.52
Mar	7.54
Apr	7.21
May	5.44
Jun	5.67
Jul	4.98
Aug	4.13
Sep	6.90
Oct	7.78
Nov	8.86
Dec	9.90



Weibull k:	1.28
Autocorrelation factor:	0.879
Diurnal pattern strength:	0.127
Hour of peak wind speed:	16
Scaled annual average:	7.03 m/s
Anemometer height:	4 m
Altitude:	29 m

Wind shear profile: Logarithmic
Surface roughness length: 0.01 m

AC Hydro:

Capital cost:	$ 64,892,000, 5,378,000
Replacement cost:	$ 0
O&M cost:	$ 533,650, 6,840/yr
Lifetime:	60 yr
Available head:	45, 30 m
Design flow rate:	12,890, 430 L/s
Min. flow ratio:	5, 15%
Max. flow ratio:	100%
Turbine efficiency:	85%
Pipe head loss:	0, 1%

Consider systems without hydro: Yes

Hydro Resource

Data source: Synthetic

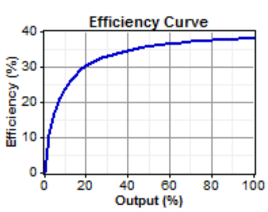
Month	Stream Flow
	(L/s)
Jan	1,824
Feb	1,471
Mar	1,706
Apr	1,647
May	4,706
Jun	4,588
Jul	4,706
Aug	4,706
Sep	4,588
Oct	4,706
Nov	4,588
Dec	3,412

Residual flow: 0 L/s
Scaled annual average: 3,568, 79 L/s

AC Generator: #574

Size (kW)	Capital ($)	Replacement ($)	O&M ($/hr)
865.000	0	600,000	2.489

Sizes to consider:	865 kW
Lifetime:	100,000 hrs
Min. load ratio:	30%
Heat recovery ratio:	0%
Fuel used:	#1 Diesel Arctic Grade
Fuel curve intercept:	0.0167 L/hr/kW
Fuel curve slope:	0.238 L/hr/kW

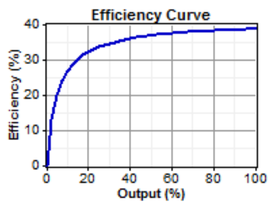


AC Generator: #576

Size (kW)	Capital ($)	Replacement ($)	O&M ($/hr)

865.000	0	600,000	2.489

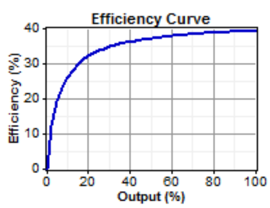
Sizes to consider: 865 kW
Lifetime: 100,000 hrs
Min. load ratio: 30%
Heat recovery ratio: 0%
Fuel used: #1 Diesel Arctic Grade
Fuel curve intercept: 0.0124 L/hr/kW
Fuel curve slope: 0.238 L/hr/kW



AC Generator: #2085

Size (kW)	Capital ($)	Replacement ($)	O&M ($/hr)
1,275.000	0	1,120,000	3.069

Sizes to consider: 1,275 kW
Lifetime: 100,000 hrs
Min. load ratio: 30%
Heat recovery ratio: 0%
Fuel used: #1 Diesel Arctic Grade
Fuel curve intercept: 0.0139 L/hr/kW
Fuel curve slope: 0.233 L/hr/kW



Fuel: #1 Diesel Arctic Grade

Price: $ 0.95, 0.95, 0.97, 1.00, 1.00/L
Lower heating value: 45.8 MJ/kg
Density: 809 kg/m3
Carbon content: 88.0%
Sulfur content: 0.0500%

Converter

Size (kW)	Capital ($)	Replacement ($)	O&M ($/yr)
100.000	64,000	64,000	6,400

Sizes to consider: 0, 100 kW
Lifetime: 15 yr
Inverter efficiency: 90%
Inverter can parallel with AC generator: Yes
Rectifier relative capacity: 100%
Rectifier efficiency: 85%

Economics

Annual real interest rate: 8%
Project lifetime: 60 yr
Capacity shortage penalty: $ 0/kWh
System fixed capital cost: $ 0

System fixed O&M cost: $ 0/yr

Generator control

Check load following: Yes
Check cycle charging: No

Allow systems with multiple generators:	Yes
Allow multiple generators to operate simultaneously:	Yes
Allow systems with generator capacity less than peak load:	No

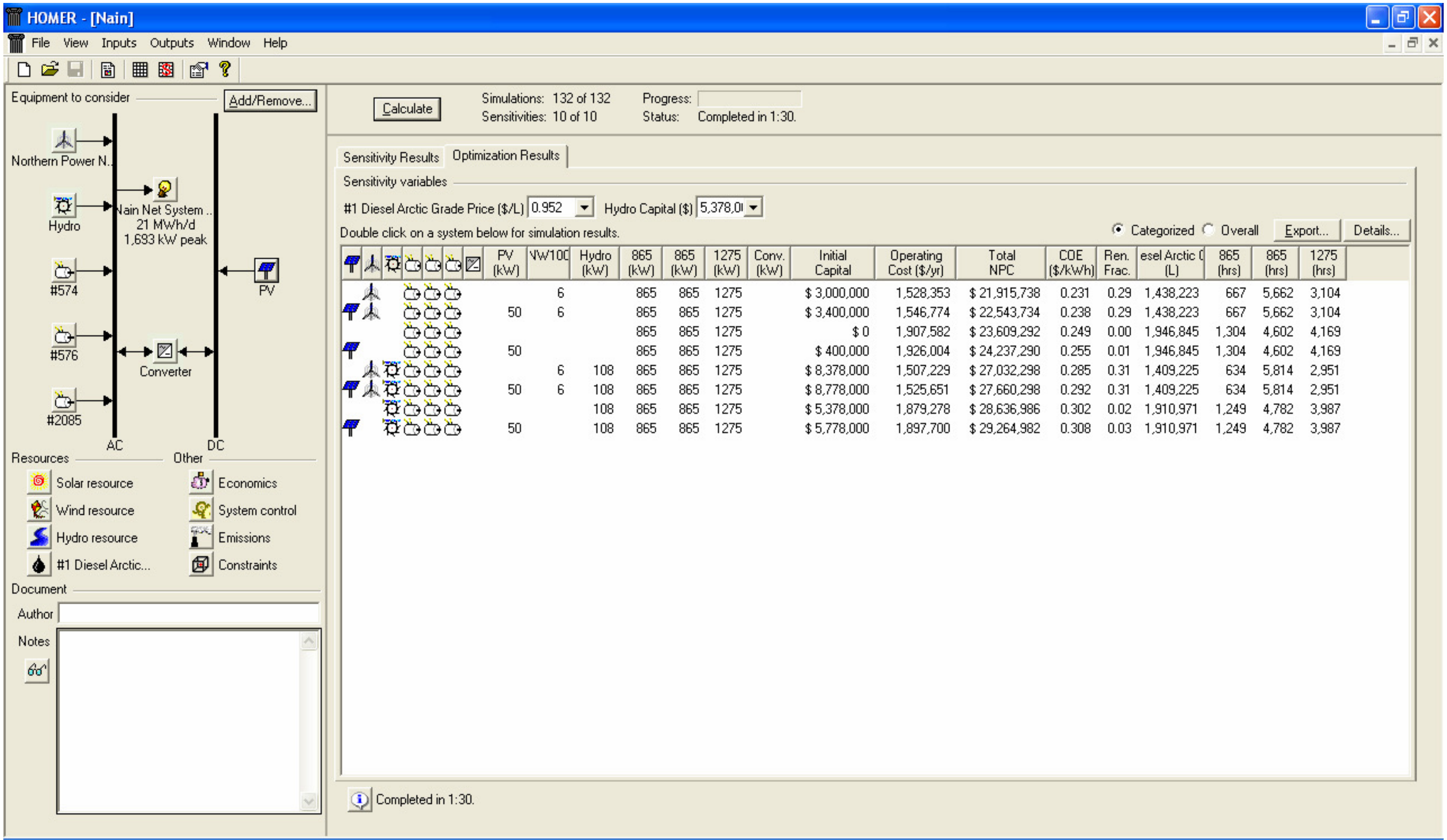
Emissions

Carbon dioxide penalty:	$ 0/t
Carbon monoxide penalty:	$ 0/t
Unburned hydrocarbons penalty:	$ 0/t
Particulate matter penalty:	$ 0/t
Sulfur dioxide penalty:	$ 0/t
Nitrogen oxides penalty:	$ 0/t

Constraints

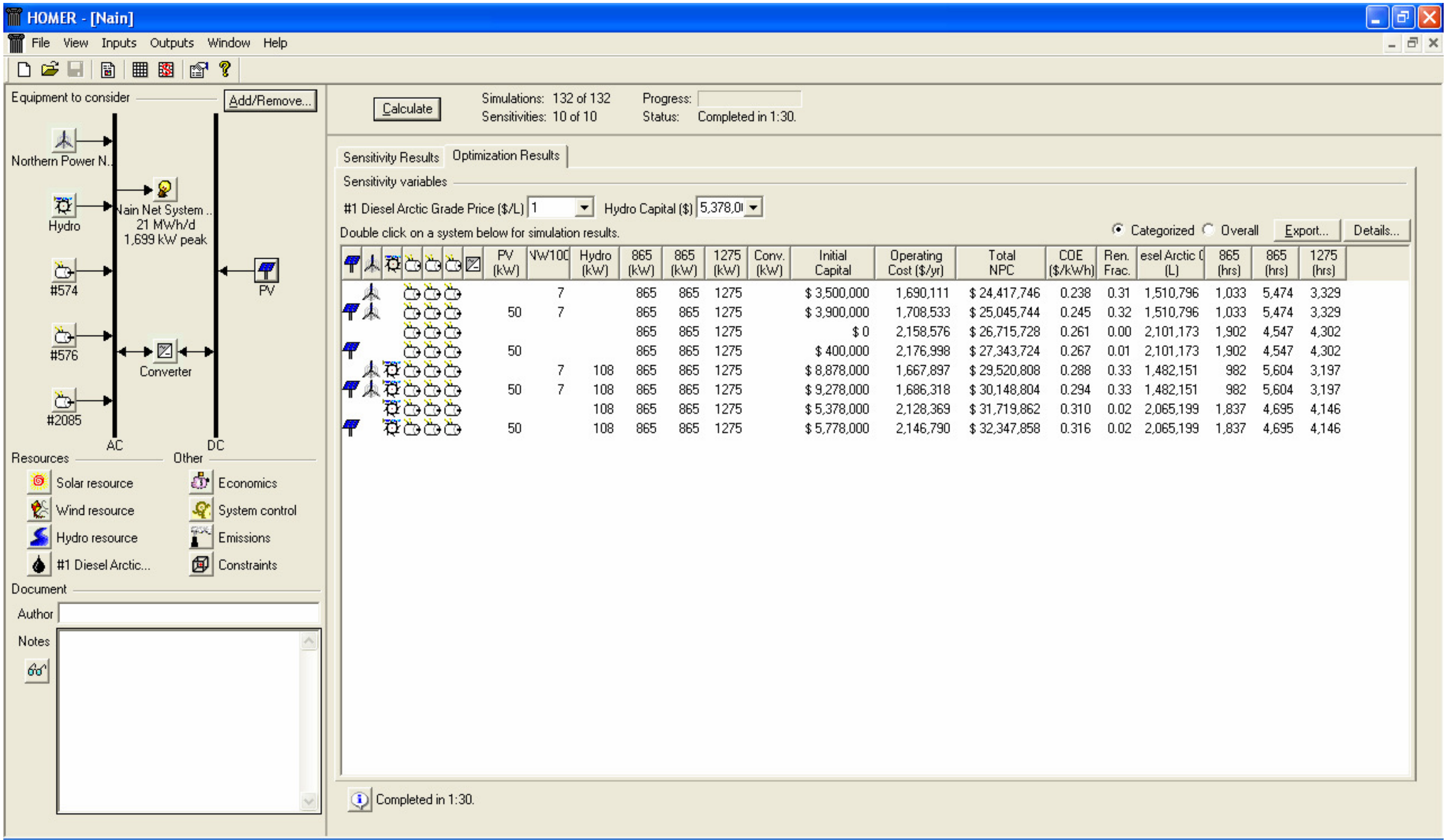
Maximum annual capacity shortage:	0%
Minimum renewable fraction:	0%

Operating reserve as percentage of hourly load:	10%
Operating reserve as percentage of peak load:	0%
Operating reserve as percentage of solar power output:	25%
Operating reserve as percentage of wind power output:	50%



PV (kW)	NW100	Hydro (kW)	865 (kW)	865 (kW)	1275 (kW)	Conv. (kW)	Initial Capital	Operating Cost ($/yr)	Total NPC	COE ($/kWh)	Ren. Frac.	esel Arctic (L)	865 (hrs)	865 (hrs)	1275 (hrs)
	6		865	865	1275		$ 3,000,000	1,528,353	$ 21,915,738	0.231	0.29	1,438,223	667	5,662	3,104
50	6		865	865	1275		$ 3,400,000	1,546,774	$ 22,543,734	0.238	0.29	1,438,223	667	5,662	3,104
			865	865	1275		$ 0	1,907,582	$ 23,609,292	0.249	0.00	1,946,845	1,304	4,602	4,169
50			865	865	1275		$ 400,000	1,926,004	$ 24,237,290	0.255	0.01	1,946,845	1,304	4,602	4,169
	6	108	865	865	1275		$ 8,378,000	1,507,229	$ 27,032,298	0.285	0.31	1,409,225	634	5,814	2,951
50	6	108	865	865	1275		$ 8,778,000	1,525,651	$ 27,660,298	0.292	0.31	1,409,225	634	5,814	2,951
		108	865	865	1275		$ 5,378,000	1,879,278	$ 28,636,986	0.302	0.02	1,910,971	1,249	4,782	3,987
50		108	865	865	1275		$ 5,778,000	1,897,700	$ 29,264,982	0.308	0.03	1,910,971	1,249	4,782	3,987

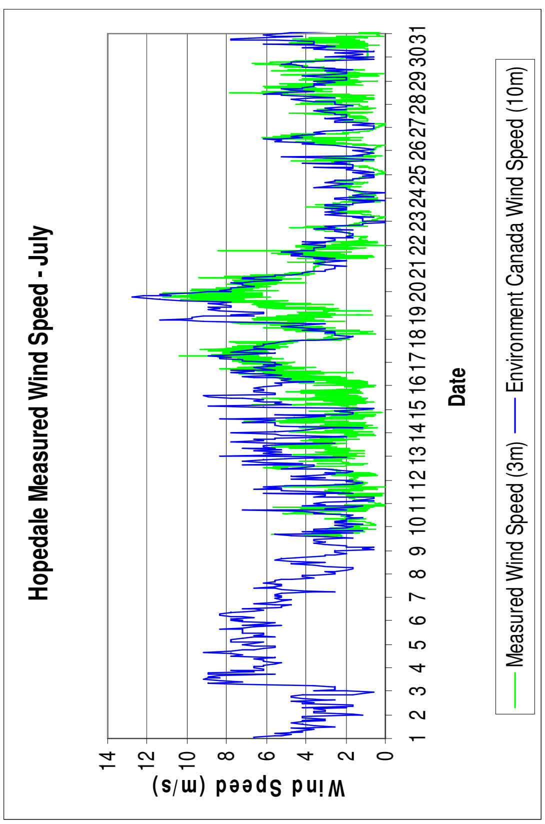
Nain HOMER Results – 2011 System Load

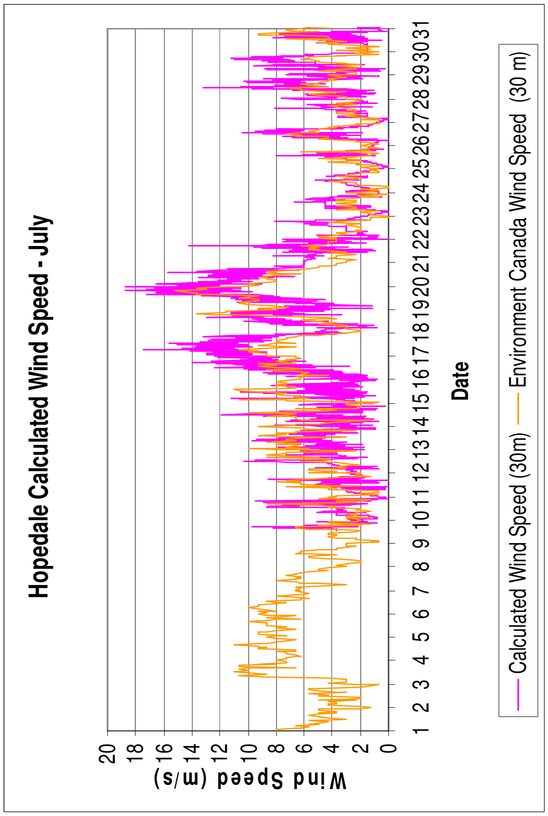


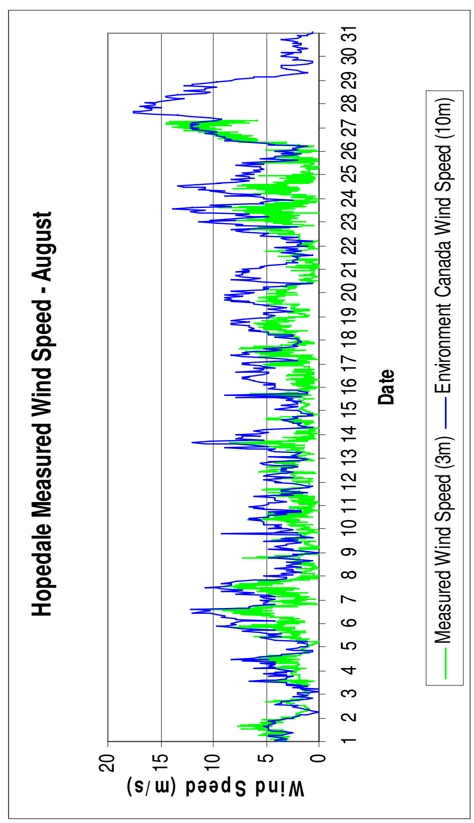
PV (kW)	NW100	Hydro (kW)	865 (kW)	865 (kW)	1275 (kW)	Conv. (kW)	Initial Capital	Operating Cost ($/yr)	Total NPC	COE ($/kWh)	Ren. Frac.	esel Arctic (L)	865 (hrs)	865 (hrs)	1275 (hrs)
	7		865	865	1275		$ 3,500,000	1,690,111	$ 24,417,746	0.238	0.31	1,510,796	1,033	5,474	3,329
50	7		865	865	1275		$ 3,900,000	1,708,533	$ 25,045,744	0.245	0.32	1,510,796	1,033	5,474	3,329
			865	865	1275		$ 0	2,158,576	$ 26,715,728	0.261	0.00	2,101,173	1,902	4,547	4,302
50			865	865	1275		$ 400,000	2,176,998	$ 27,343,724	0.267	0.01	2,101,173	1,902	4,547	4,302
	7	108	865	865	1275		$ 8,878,000	1,667,897	$ 29,520,808	0.288	0.33	1,482,151	982	5,604	3,197
50	7	108	865	865	1275		$ 9,278,000	1,686,318	$ 30,148,804	0.294	0.33	1,482,151	982	5,604	3,197
		108	865	865	1275		$ 5,378,000	2,128,369	$ 31,719,862	0.310	0.02	2,065,199	1,837	4,695	4,146
50		108	865	865	1275		$ 5,778,000	2,146,790	$ 32,347,858	0.316	0.02	2,065,199	1,837	4,695	4,146

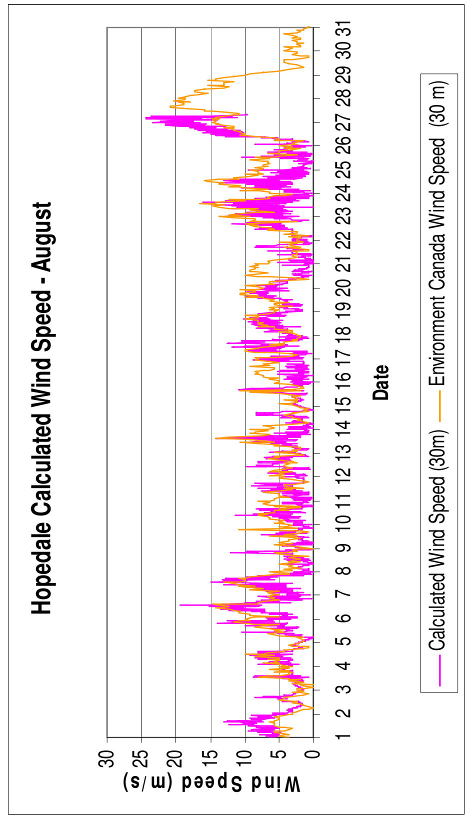
Nain HOMER Results – 2015 System Load

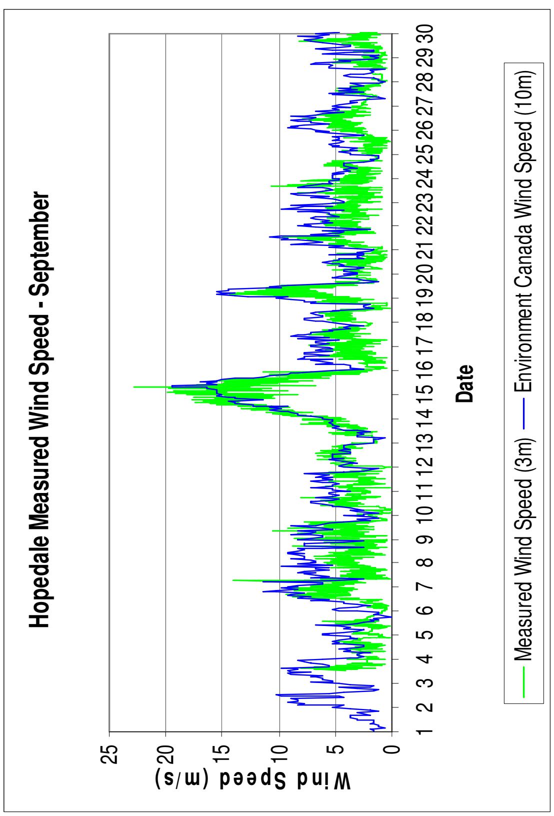
APPENDIX B - HOPEDALE

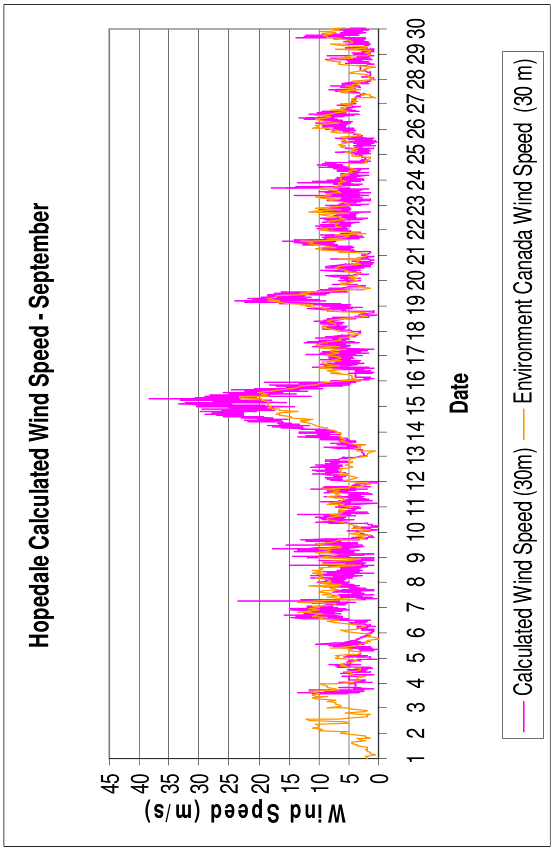

Hopedale Measured Wind Speed - July
Wind Speed (m/s)
Date
Measured Wind Speed (3m)
Environment Canada Wind Speed (10m)

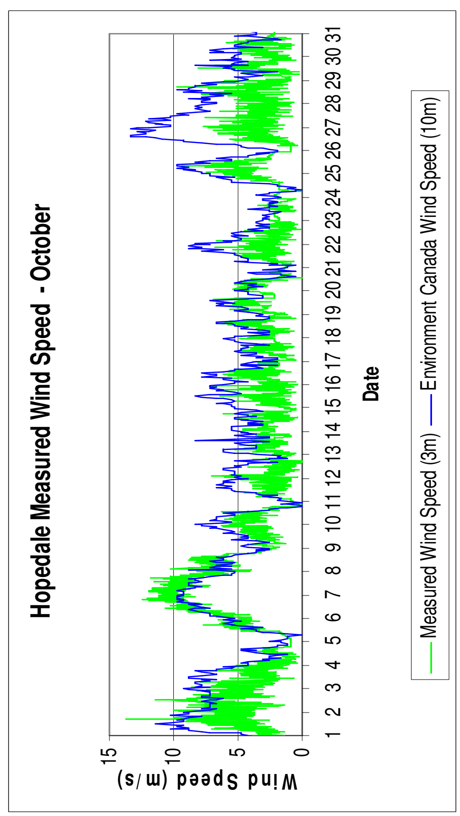

Hopedale Calculated Wind Speed - July
Wind Speed (m/s)
Date
Calculated Wind Speed (30m)
Environment Canada Wind Speed (30 m)

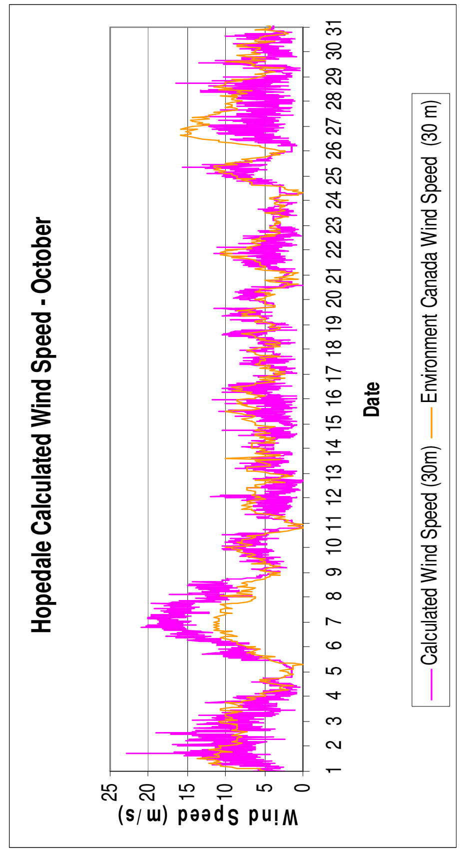

Hopedale Measured Wind Speed - August
Wind Speed (m/s)
Date
Measured Wind Speed (3m)
Environment Canada Wind Speed (10m)

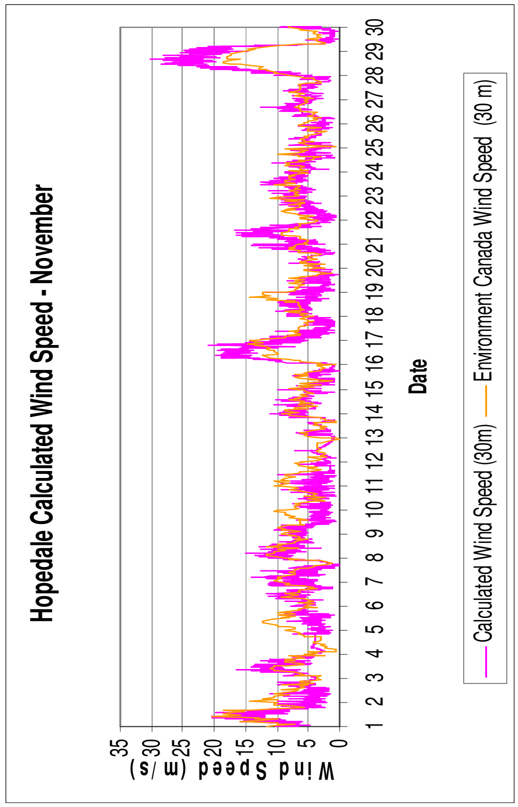

Hopedale Calculated Wind Speed - August
Wind Speed (m/s)
Date
Calculated Wind Speed (30m)
Environment Canada Wind Speed (30 m)

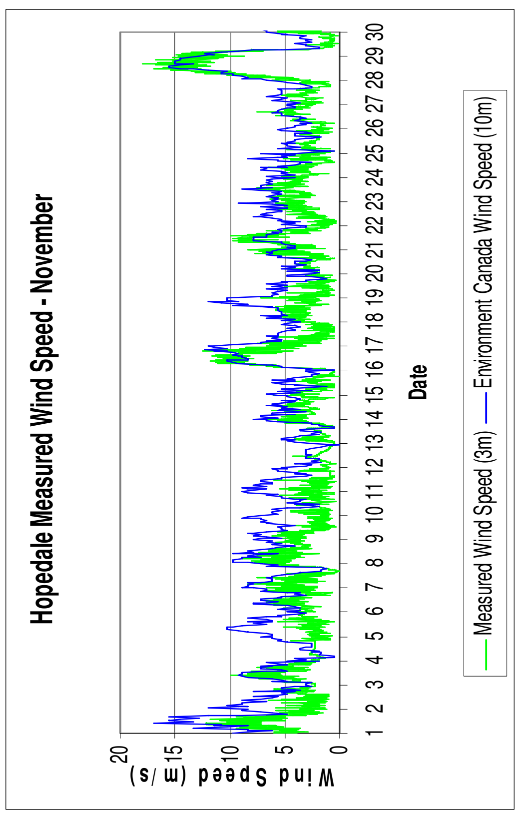

Hopedale Measured Wind Speed - September
Wind Speed (m/s)
Date
Measured Wind Speed (3m)
Environment Canada Wind Speed (10m)

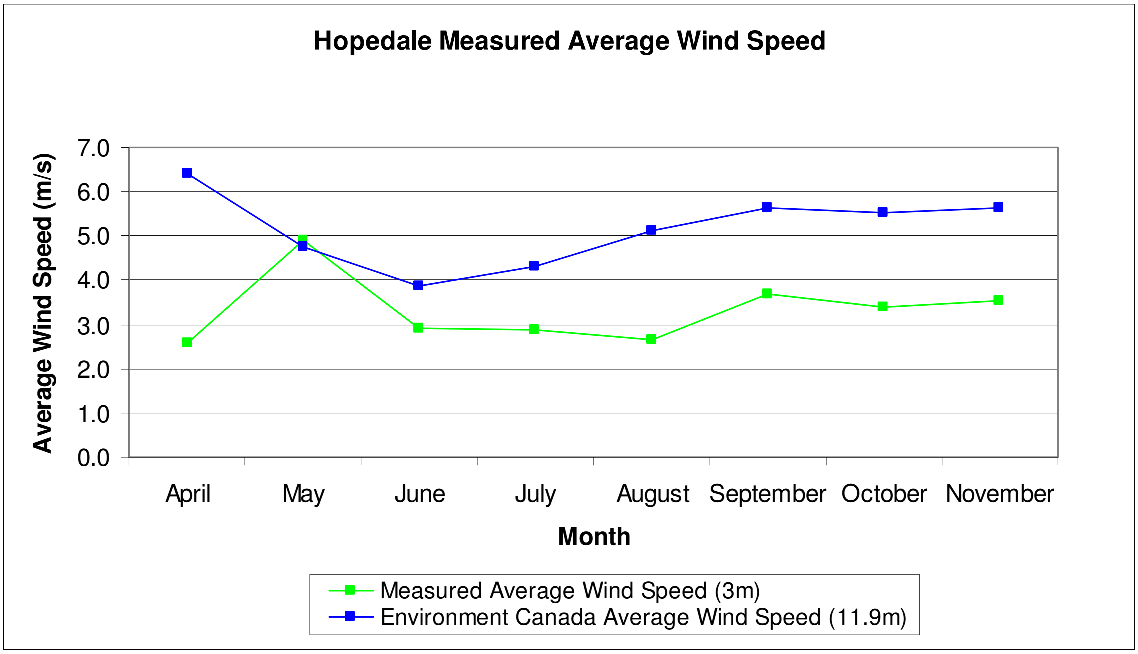

Hopedale Calculated Wind Speed - September
Wind Speed (m/s)
Date
Calculated Wind Speed (30m)
Environment Canada Wind Speed (30 m)

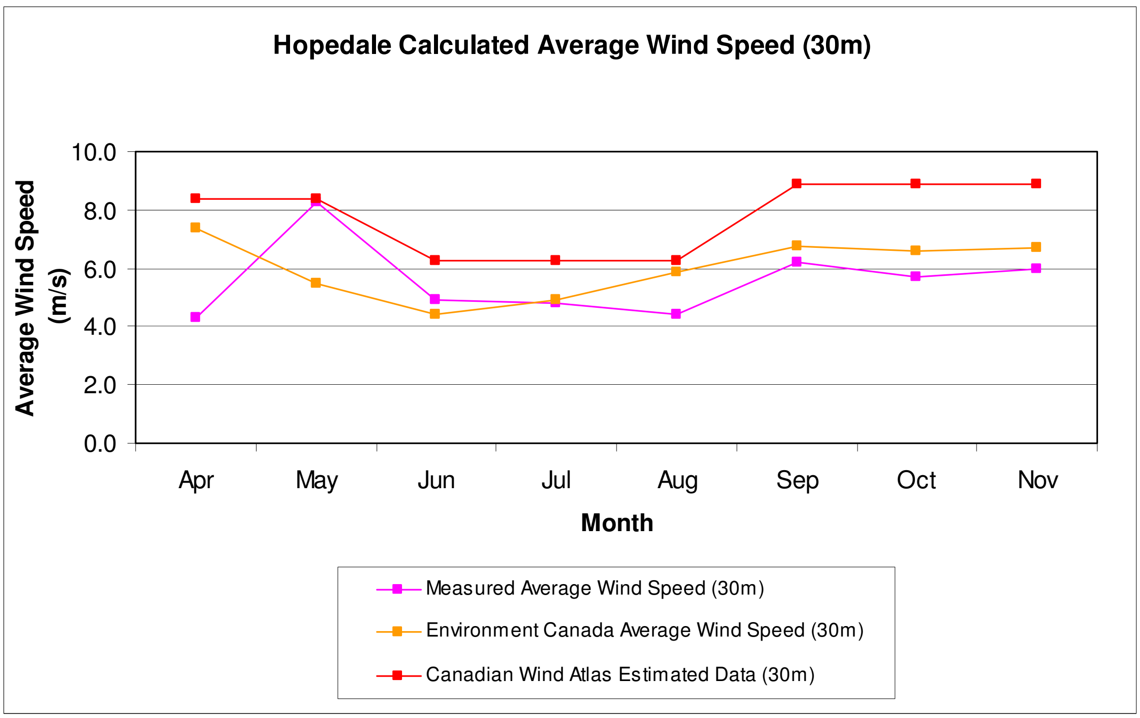

Hopedale Measured Wind Speed - October
Wind Speed (m/s)
Date
Measured Wind Speed (3m)
Environment Canada Wind Speed (10m)

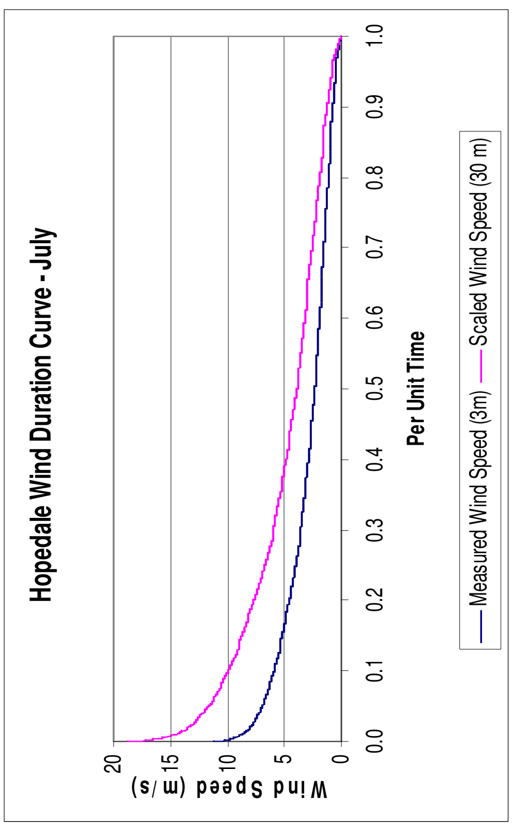

Hopedale Calculated Wind Speed - October
Wind Speed (m/s)
Date
Calculated Wind Speed (30m)
Environment Canada Wind Speed (30 m)

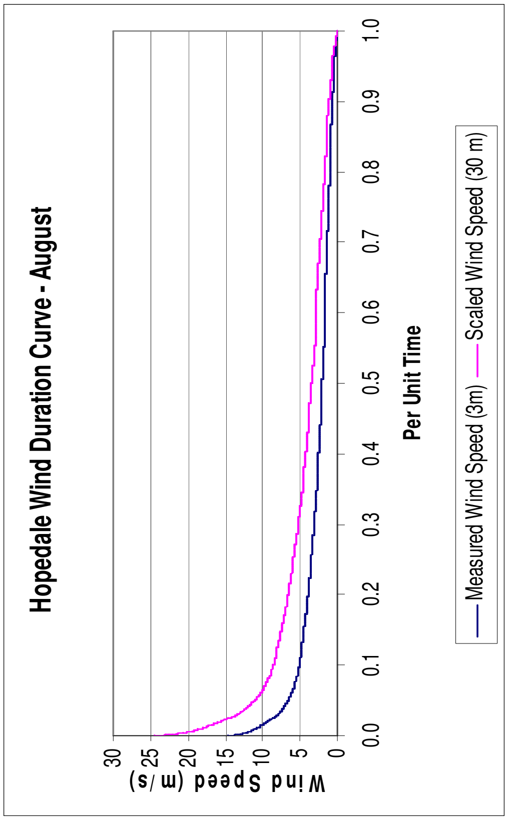

Hopedale Calculated Wind Speed - November
Wind Speed (m/s)
Date
Calculated Wind Speed (30m)
Environment Canada Wind Speed (30 m)

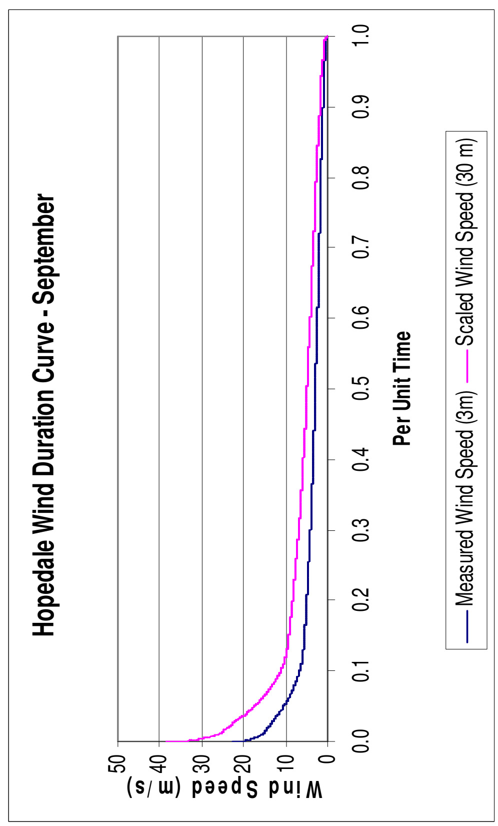

Hopedale Measured Wind Speed - November
Wind Speed (m/s)
Date
Measured Wind Speed (3m)
Environment Canada Wind Speed (10m)

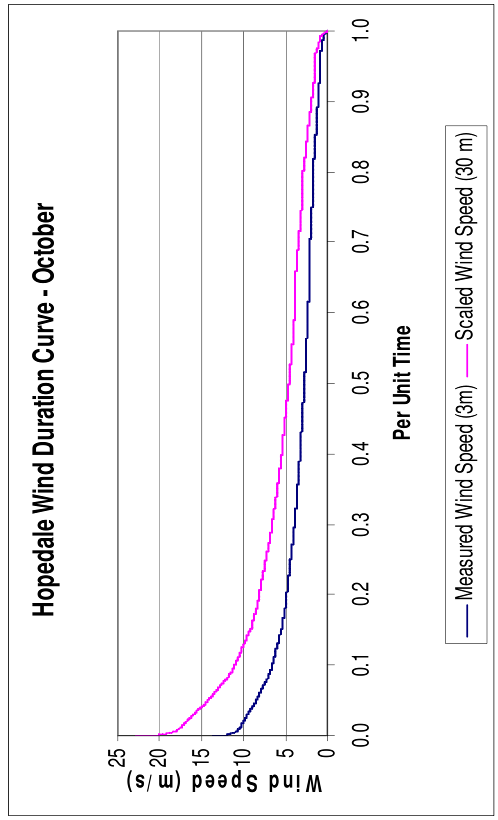

Hopedale Measured Average Wind Speed
Average Wind Speed (m/s)
7.0
6.0
5.0
4.0
3.0
2.0
1.0
0.0
April
May
June
July
August
September
October
November
Month
Measured Average Wind Speed (3m)
Environment Canada Average Wind Speed (11.9m)

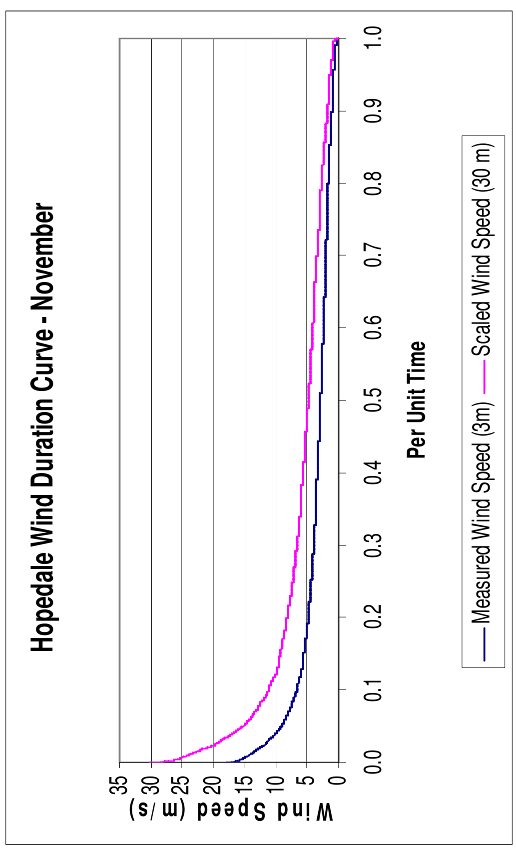

Hopedale Calculated Average Wind Speed (30m)
Average Wind Speed (m/s)
10.0
8.0
6.0
4.0
2.0
0.0
Apr
May
Jun
Jul
Aug
Sep
Oct
Nov
Month
Measured Average Wind Speed (30m)
Environment Canada Average Wind Speed (30m)
Canadian Wind Atlas Estimated Data (30m)

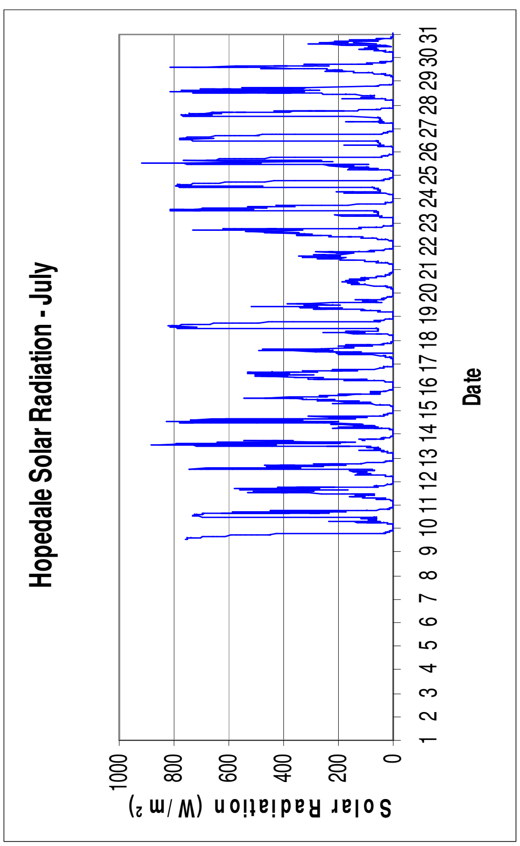

Hopedale Wind Duration Curve - July
Wind Speed (m/s)
20
15
10
5
0
0.0
0.1
0.2
0.3
0.4
0.5
0.6
0.7
0.8
0.9
1.0
Per Unit Time
Measured Wind Speed (3m)
Scaled Wind Speed (30 m)

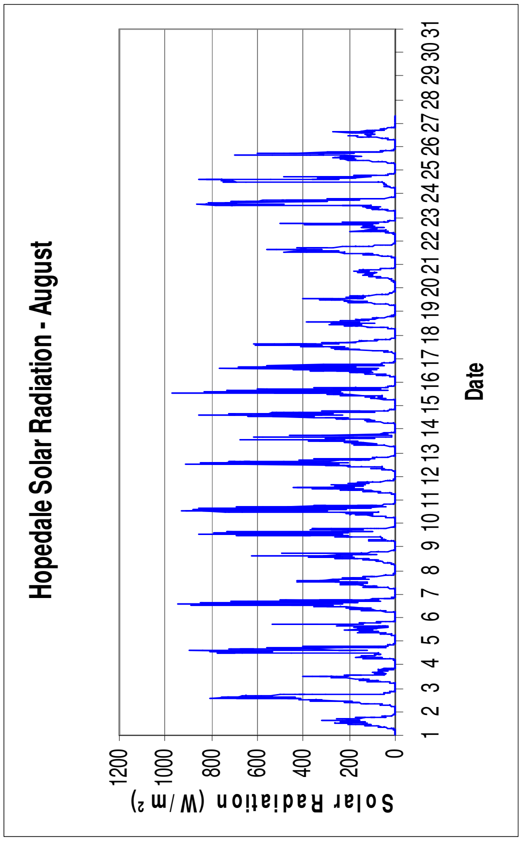

Hopedale Wind Duration Curve - August
Wind Speed (m/s)
30
25
20
15
10
5
0
0.0
0.1
0.2
0.3
0.4
0.5
0.6
0.7
0.8
0.9
1.0
Per Unit Time
Measured Wind Speed (3m)
Scaled Wind Speed (30 m)

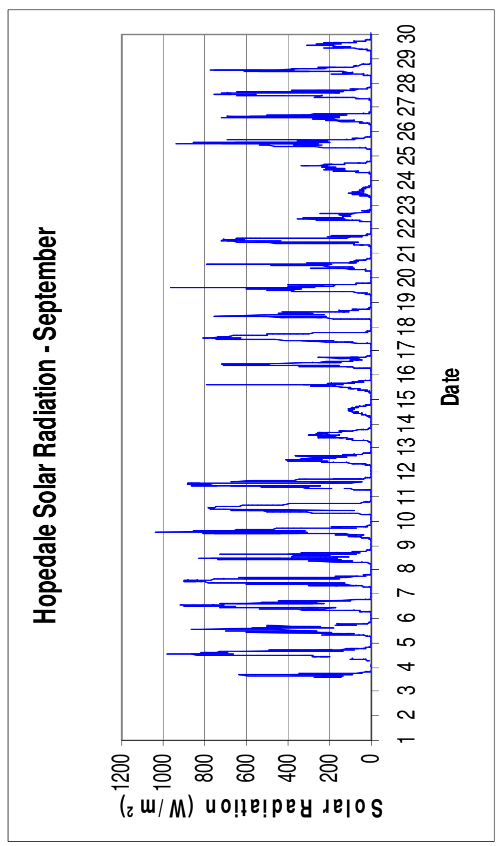

Hopedale Wind Duration Curve - September
Wind Speed (m/s)
50
40
30
20
10
0
0.0
0.1
0.2
0.3
0.4
0.5
0.6
0.7
0.8
0.9
1.0
Per Unit Time
Measured Wind Speed (3m)
Scaled Wind Speed (30 m)

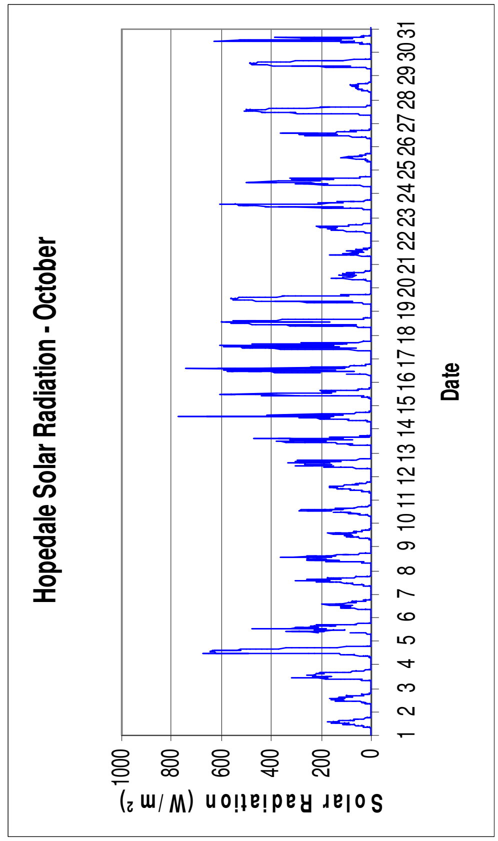

Hopedale Wind Duration Curve - October
Wind Speed (m/s)
25
20
15
10
5
0
0.0
0.1
0.2
0.3
0.4
0.5
0.6
0.7
0.8
0.9
1.0
Per Unit Time
Measured Wind Speed (3m)
Scaled Wind Speed (30 m)

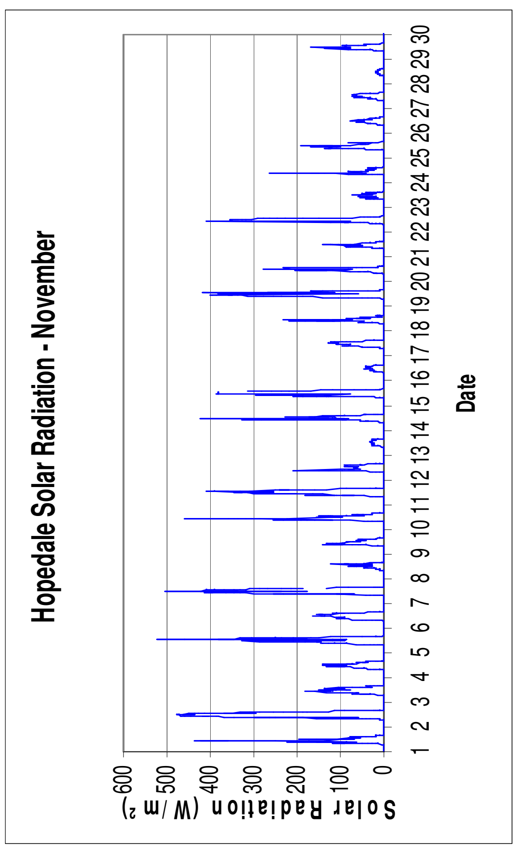

Hopedale Wind Duration Curve - November
Wind Speed (m/s)
35
30
25
20
15
10
5
0
0.0
0.1
0.2
0.3
0.4
0.5
0.6
0.7
0.8
0.9
1.0
Per Unit Time
Measured Wind Speed (3m)
Scaled Wind Speed (30 m)

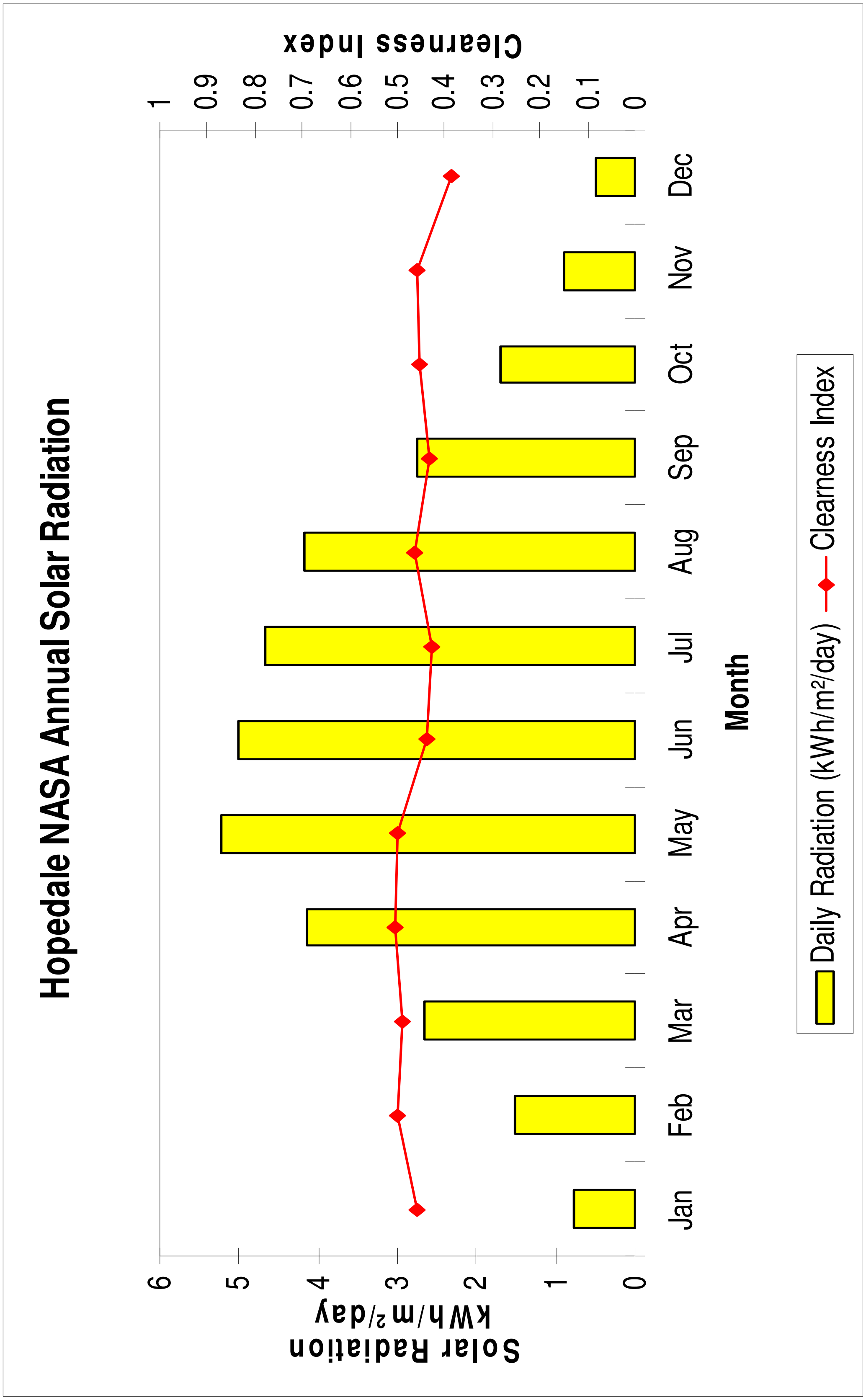

Hopedale Solar Radiation - July
Solar Radiation (W/m²)
Date

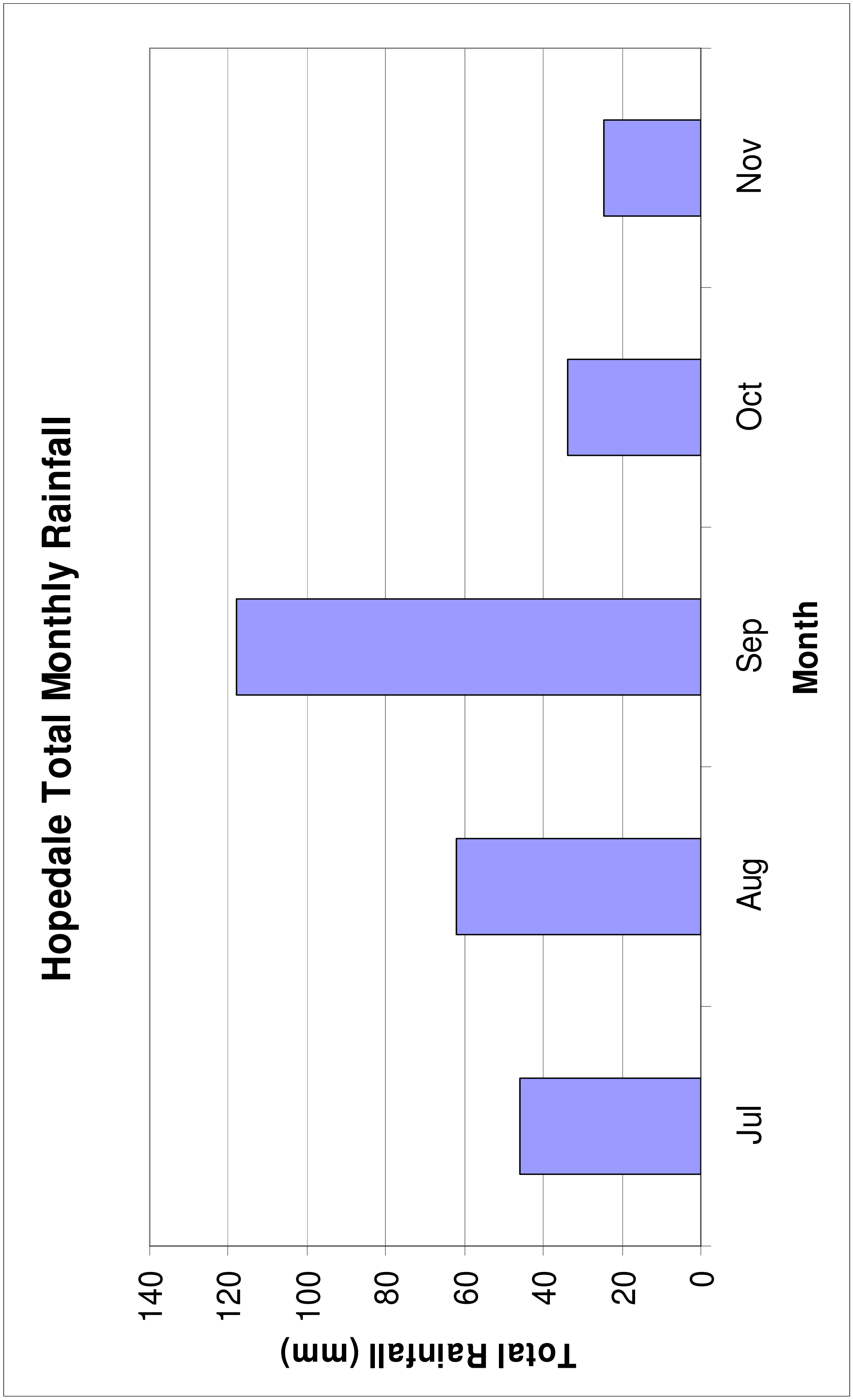

Hopedale Solar Radiation - August
Solar Radiation (W/m²)
Date


Hopedale Solar Radiation - September
Solar Radiation (W/m²)
Date


Hopedale Solar Radiation - October
Solar Radiation (W/m²)
Date


Hopedale Solar Radiation - November
Solar Radiation (W/m²)
600
500
400
300
200
100
0
1 2 3 4 5 6 7 8 9 10 11 12 13 14 15 16 17 18 19 20 21 22 23 24 25 26 27 28 29 30
Date


Hopedale NASA Annual Solar Radiation
Solar Radiation
kWh/m²/day
Clearness Index
Month
Jan
Feb
Mar
Apr
May
Jun
Jul
Aug
Sep
Oct
Nov
Dec
0
1
2
3
4
5
6
0.1
0.2
0.3
0.4
0.5
0.6
0.7
0.8
0.9
Daily Radiation (kWh/m²/day)
Clearness Index

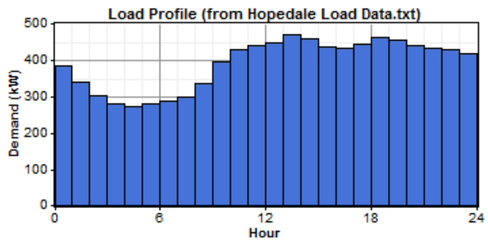

Hopedale Total Monthly Rainfall
Total Rainfall (mm)
140
120
100
80
60
40
20
0
Jul
Aug
Sep
Oct
Nov
Month

HOMER Input Summary

File name: Hopedale.hmr
File version: 2.67 beta
Author:
Notes:

AC Load: Hopedale Net System Load

Data source:	Hopedale Load Data.txt
Daily noise:	16.9%
Hourly noise:	22.5%
Scaled annual average:	11,616, 11,959, 12,252, 12,540, 12,805 kWh/d
Scaled peak load:	991, 1,020, 1,045, 1,070, 1,092 kW
Load factor:	0.488



PV

Size (kW)	Capital ($)	Replacement ($)	O&M ($/yr)
50.000	400,000	400,000	10,000
100.000	750,000	750,000	15,000

Sizes to consider:	0, 50, 100 kW
Lifetime:	20 yr
Derating factor:	80%
Tracking system:	No Tracking
Slope:	55.5 deg
Azimuth:	0 deg
Ground reflectance:	20%

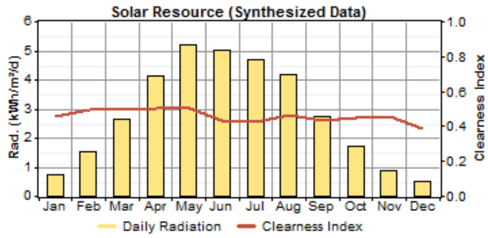
Solar Resource

Latitude: 55 degrees 27 minutes North
Longitude: 60 degrees 11 minutes West
Time zone: GMT -4:00

Data source: Synthetic

Month	Clearness Index	Average Radiation
		(kWh/m^2/day)
Jan	0.460	0.760
Feb	0.498	1.530
Mar	0.492	2.670
Apr	0.506	4.140
May	0.501	5.220
Jun	0.437	5.010
Jul	0.428	4.680
Aug	0.463	4.170
Sep	0.432	2.740
Oct	0.453	1.700
Nov	0.459	0.900
Dec	0.386	0.490

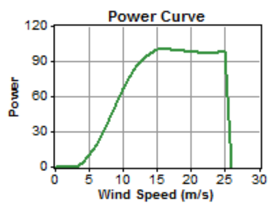
Scaled annual average: 2.83 kWh/m²/d



AC Wind Turbine: Northern Power NW100/21

Quantity	Capital ($)	Replacement ($)	O&M ($/yr)
1	500,000	400,000	10,000

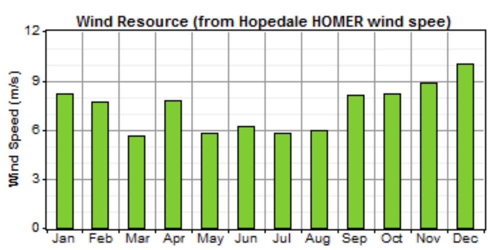
Quantities to consider: 0, 1, 2, 3, 4, 5, 6, 7, 8, 9, 10
Lifetime: 20 yr
Hub height: 37 m



Wind Resource

Data source: Hopedale HOMER wind speed.txt

Month	Wind Speed (m/s)
Jan	8.2
Feb	7.7
Mar	5.6
Apr	7.8
May	5.8
Jun	6.2
Jul	5.8
Aug	6.0
Sep	8.1
Oct	8.2
Nov	8.9
Dec	10.0



Weibull k: 1.55
Autocorrelation factor: 0.902
Diurnal pattern strength: 0.113
Hour of peak wind speed: 14
Scaled annual average: 7.34 m/s
Anemometer height: 3 m
Altitude: 6 m

Wind shear profile: Logarithmic
Surface roughness length: 0.1 m

AC Hydro:

Capital cost:	$ 41,975,000, 31,690,000, 21,230,000, 11,810,000
Replacement cost:	$ 0
O&M cost:	$ 516,880, 516,880, 516,880, 37,220/yr
Lifetime:	60 yr
Available head:	20, 14, 14, 45 m
Design flow rate:	63,280, 63,280, 31,110, 1,410 L/s
Min. flow ratio:	15, 15, 15, 10%
Max. flow ratio:	100%
Turbine efficiency:	85%
Pipe head loss:	0%

Consider systems without hydro: Yes

Hydro Resource

Data source: Synthetic

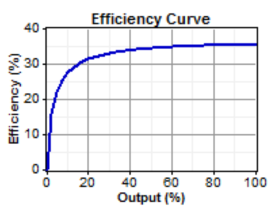
Month	Stream Flow (L/s)
Jan	3,470
Feb	2,235
Mar	2,000
Apr	2,471
May	9,294
Jun	8,941
Jul	9,294
Aug	9,294
Sep	8,941
Oct	9,294
Nov	8,941
Dec	5,765

Residual flow: 0 L/s
Scaled annual average: 6,691, 4,652, 4,652, 327 L/s

AC Generator: #2074

Size (kW)	Capital ($)	Replacement ($)	O&M ($/hr)
569.000	0	600,000	1.850

Sizes to consider:	569 kW
Lifetime:	100,000 hrs
Min. load ratio:	30%
Heat recovery ratio:	0%
Fuel used:	#1 Diesel Arctic Grade
Fuel curve intercept:	0.00881 L/hr/kW
Fuel curve slope:	0.264 L/hr/kW

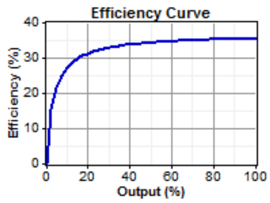


AC Generator: #2053

Size (kW)	Capital ($)	Replacement ($)	O&M ($/hr)

545.000	0	400,000	1.684

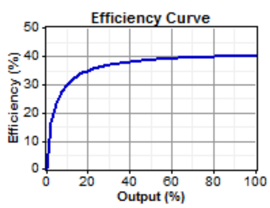
Sizes to consider: 545 kW
Lifetime: 100,000 hrs
Min. load ratio: 30%
Heat recovery ratio: 0%
Fuel used: #1 Diesel Arctic Grade
Fuel curve intercept: 0.0092 L/hr/kW
Fuel curve slope: 0.264 L/hr/kW



AC Generator: #2054

Size (kW)	Capital ($)	Replacement ($)	O&M ($/hr)
475.000	0	400,000	1.684

Sizes to consider: 475 kW
Lifetime: 100,000 hrs
Min. load ratio: 30%
Heat recovery ratio: 0%
Fuel used: #1 Diesel Arctic Grade
Fuel curve intercept: 0.00921 L/hr/kW
Fuel curve slope: 0.233 L/hr/kW



Fuel: #1 Diesel Arctic Grade

Price: $ 0.97, 0.97, 0.99, 1.02, 1.02/L
Lower heating value: 45.8 MJ/kg
Density: 809 kg/m3
Carbon content: 88.0%
Sulfur content: 0.0500%

Converter

Size (kW)	Capital ($)	Replacement ($)	O&M ($/yr)
100.000	64,000	64,000	6,400

Sizes to consider: 0, 100 kW
Lifetime: 15 yr
Inverter efficiency: 90%
Inverter can parallel with AC generator: Yes
Rectifier relative capacity: 100%
Rectifier efficiency: 85%

Economics

Annual real interest rate: 8%
Project lifetime: 60 yr
Capacity shortage penalty: $ 0/kWh
System fixed capital cost: $ 0

System fixed O&M cost:	$ 0/yr

Generator control

Check load following:	Yes
Check cycle charging:	No

Allow systems with multiple generators:	Yes
Allow multiple generators to operate simultaneously:	Yes
Allow systems with generator capacity less than peak load:	No

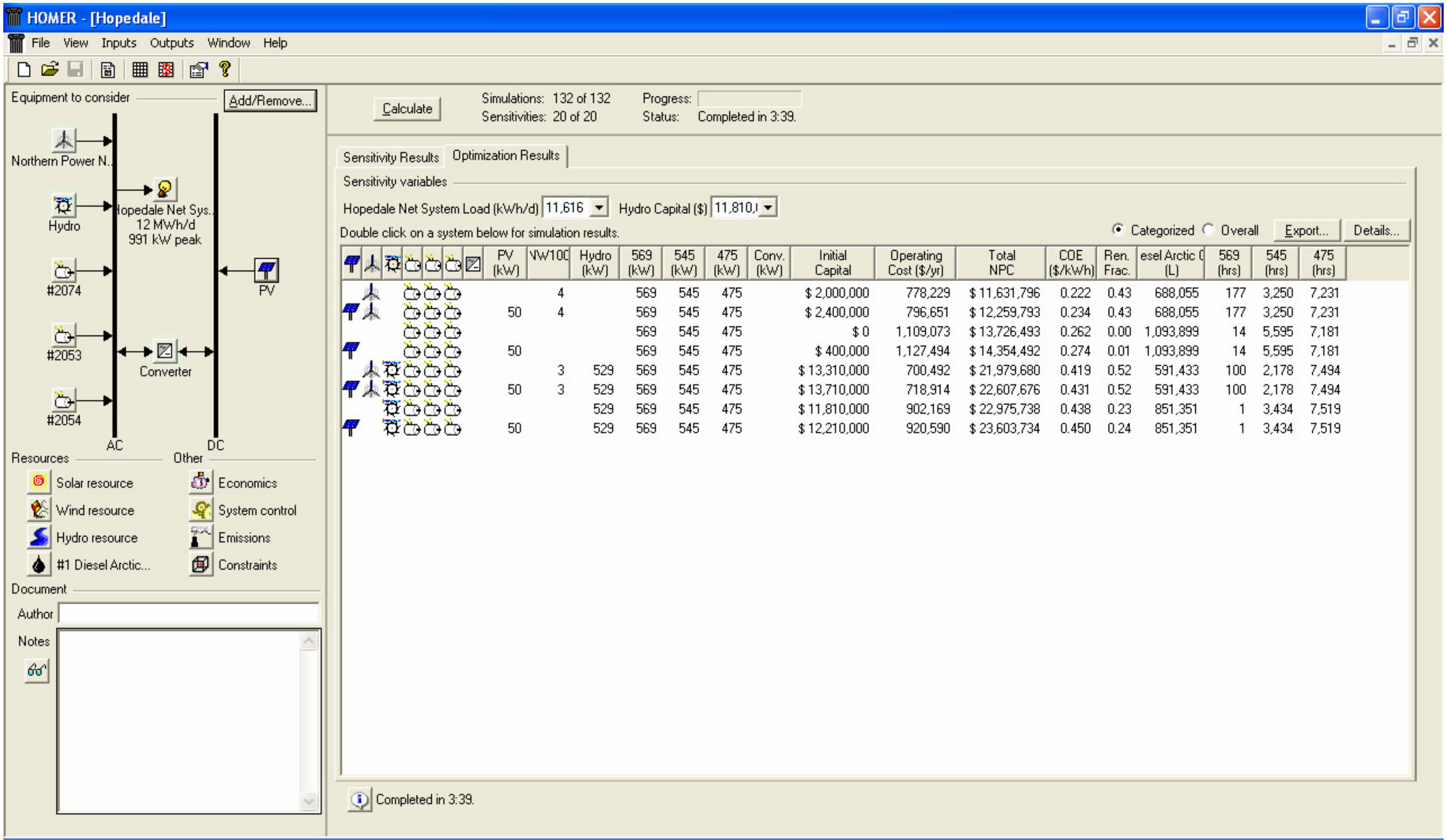
Emissions

Carbon dioxide penalty:	$ 0/t
Carbon monoxide penalty:	$ 0/t
Unburned hydrocarbons penalty:	$ 0/t
Particulate matter penalty:	$ 0/t
Sulfur dioxide penalty:	$ 0/t
Nitrogen oxides penalty:	$ 0/t

Constraints

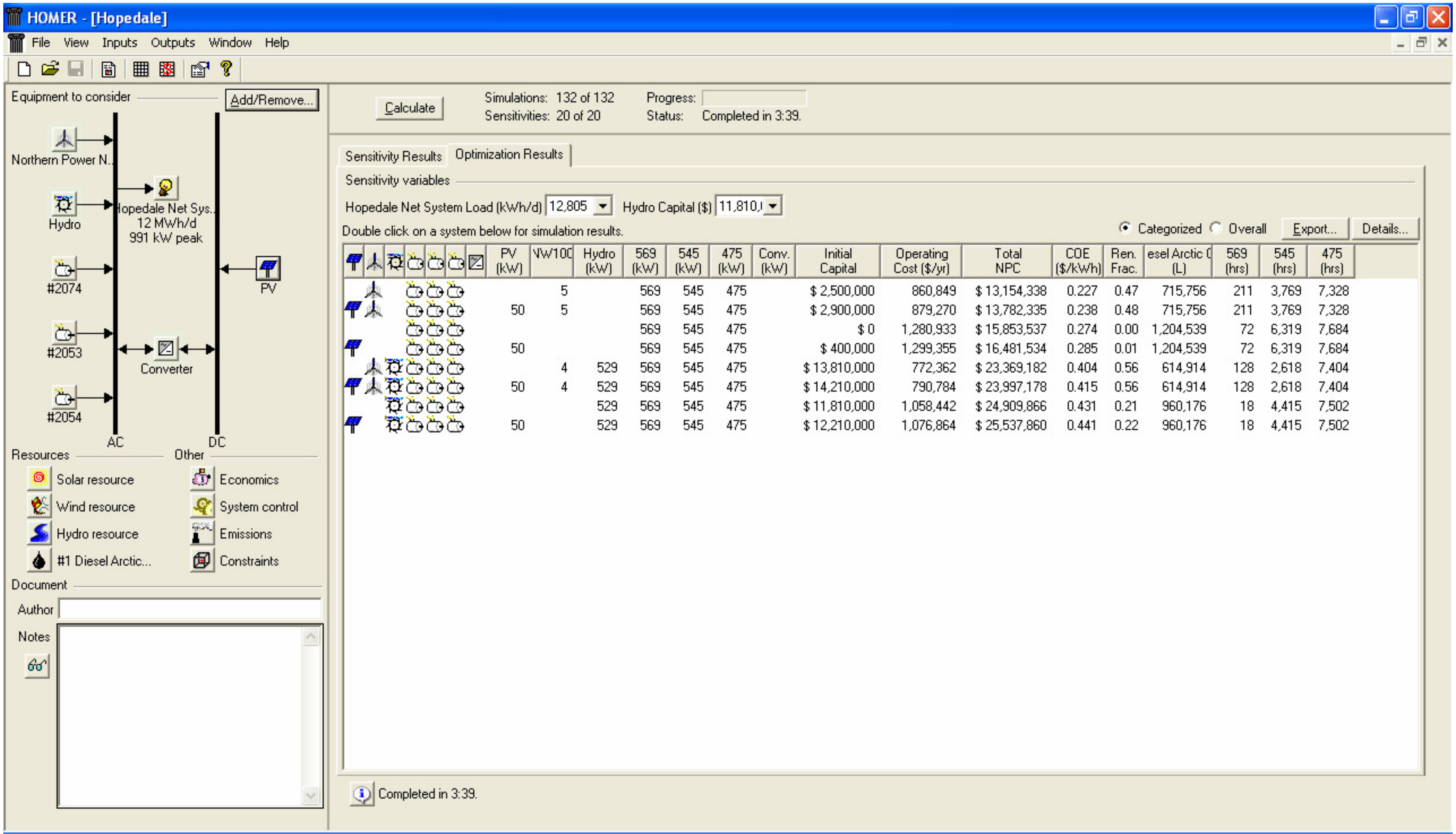
Maximum annual capacity shortage:	0%
Minimum renewable fraction:	0%

Operating reserve as percentage of hourly load:	10%
Operating reserve as percentage of peak load:	0%
Operating reserve as percentage of solar power output:	25%
Operating reserve as percentage of wind power output:	50%



PV (kW)	NW100	Hydro (kW)	569 (kW)	545 (kW)	475 (kW)	Conv. (kW)	Initial Capital	Operating Cost ($/yr)	Total NPC	COE ($/kWh)	Ren. Frac.	esel Arctic ((L)	569 (hrs)	545 (hrs)	475 (hrs)
	4		569	545	475		$ 2,000,000	778,229	$ 11,631,796	0.222	0.43	688,055	177	3,250	7,231
50	4		569	545	475		$ 2,400,000	796,651	$ 12,259,793	0.234	0.43	688,055	177	3,250	7,231
			569	545	475		$ 0	1,109,073	$ 13,726,493	0.262	0.00	1,093,899	14	5,595	7,181
50			569	545	475		$ 400,000	1,127,494	$ 14,354,492	0.274	0.01	1,093,899	14	5,595	7,181
	3	529	569	545	475		$ 13,310,000	700,492	$ 21,979,680	0.419	0.52	591,433	100	2,178	7,494
50	3	529	569	545	475		$ 13,710,000	718,914	$ 22,607,676	0.431	0.52	591,433	100	2,178	7,494
		529	569	545	475		$ 11,810,000	902,169	$ 22,975,738	0.438	0.23	851,351	1	3,434	7,519
50		529	569	545	475		$ 12,210,000	920,590	$ 23,603,734	0.450	0.24	851,351	1	3,434	7,519

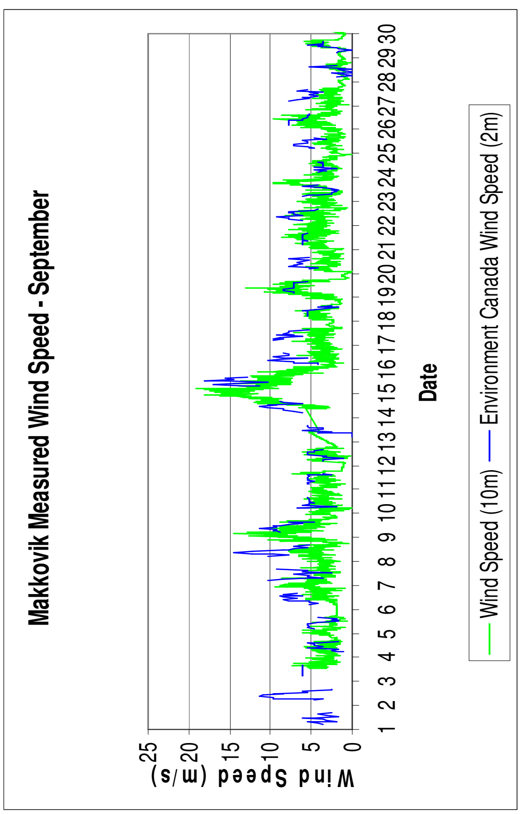
Hopedale HOMER Results – 2011 System Load

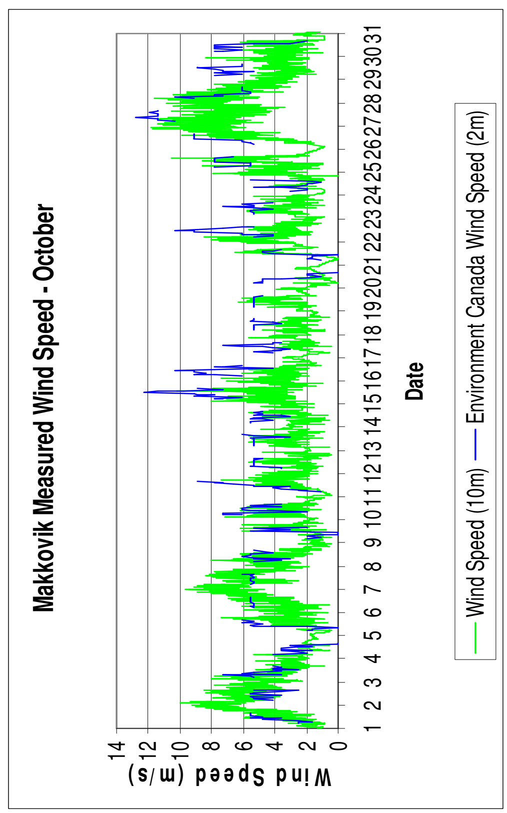


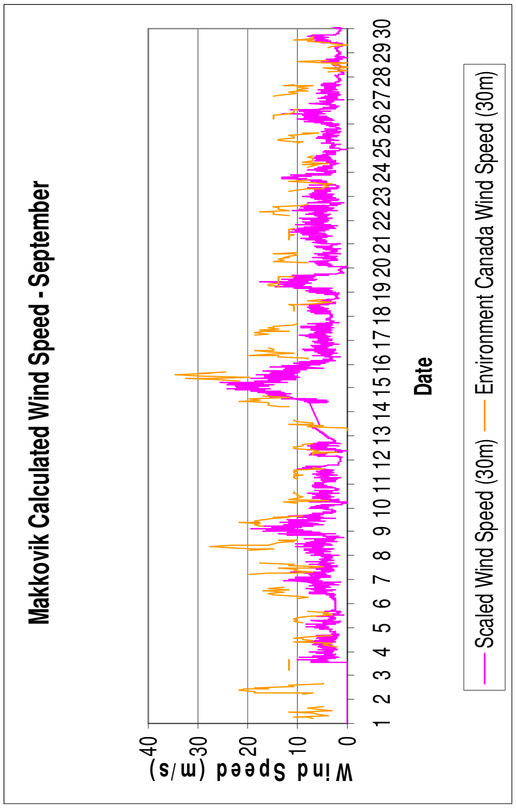
PV (kW)	VW100	Hydro (kW)	569 (kW)	545 (kW)	475 (kW)	Conv. (kW)	Initial Capital	Operating Cost ($/yr)	Total NPC	COE ($/kWh)	Ren. Frac.	esel Arctic (L)	569 (hrs)	545 (hrs)	475 (hrs)
	5		569	545	475		$ 2,500,000	860,849	$ 13,154,338	0.227	0.47	715,756	211	3,769	7,328
50	5		569	545	475		$ 2,900,000	879,270	$ 13,782,335	0.238	0.48	715,756	211	3,769	7,328
			569	545	475		$ 0	1,280,933	$ 15,853,537	0.274	0.00	1,204,539	72	6,319	7,684
50			569	545	475		$ 400,000	1,299,355	$ 16,481,534	0.285	0.01	1,204,539	72	6,319	7,684
	4	529	569	545	475		$ 13,810,000	772,362	$ 23,369,182	0.404	0.56	614,914	128	2,618	7,404
50	4	529	569	545	475		$ 14,210,000	790,784	$ 23,997,178	0.415	0.56	614,914	128	2,618	7,404
		529	569	545	475		$ 11,810,000	1,058,442	$ 24,909,866	0.431	0.21	960,176	18	4,415	7,502
50		529	569	545	475		$ 12,210,000	1,076,864	$ 25,537,860	0.441	0.22	960,176	18	4,415	7,502

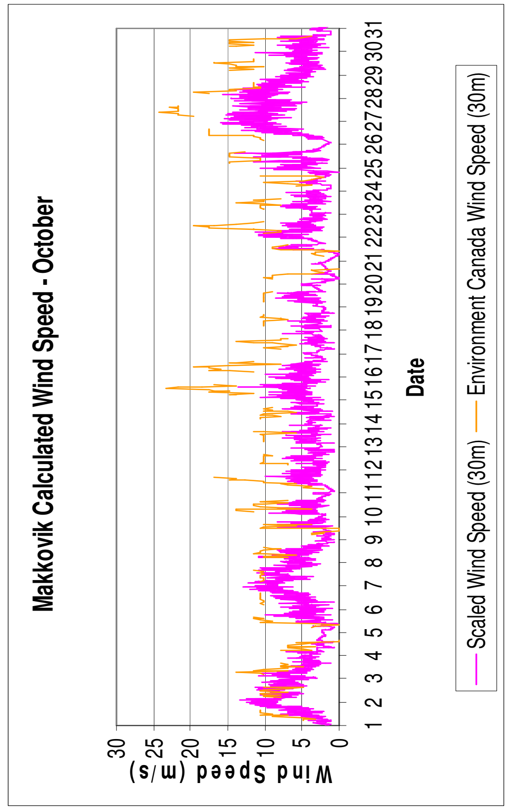
Hopedale HOMER Results – 2015 System Load

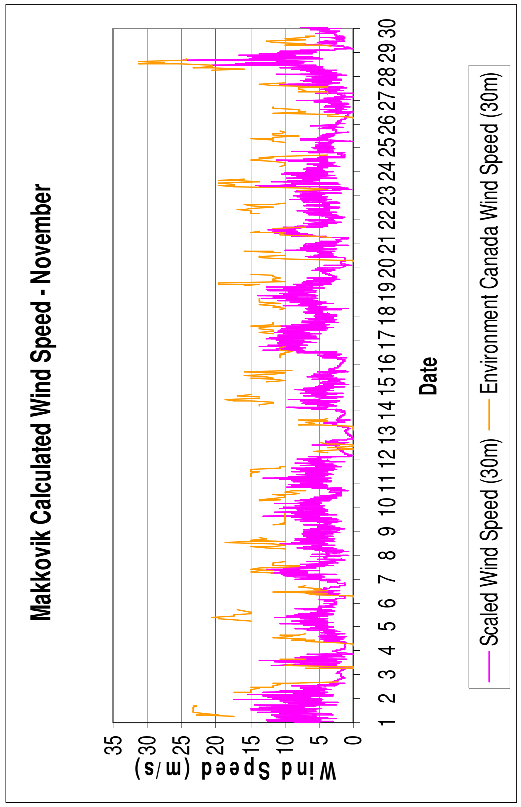
APPENDIX C - MAKKOVIK

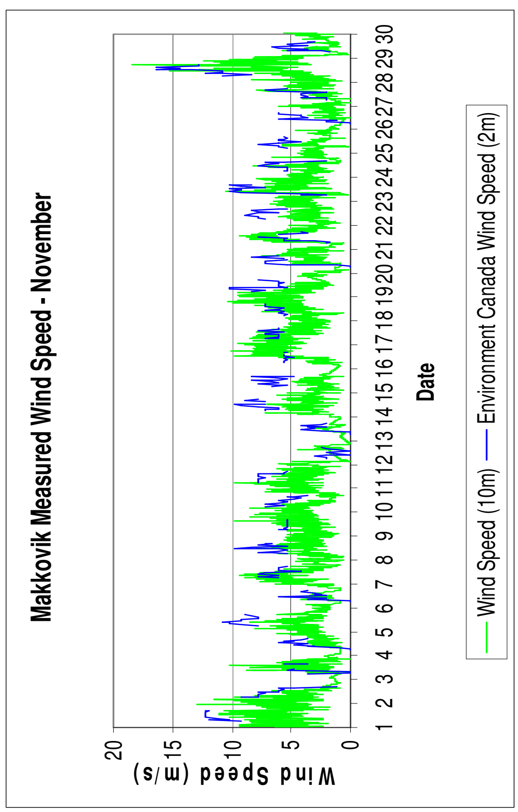

Makkovik Measured Wind Speed - September
Wind Speed (m/s)
Date
Wind Speed (10m)
Environment Canada Wind Speed (2m)

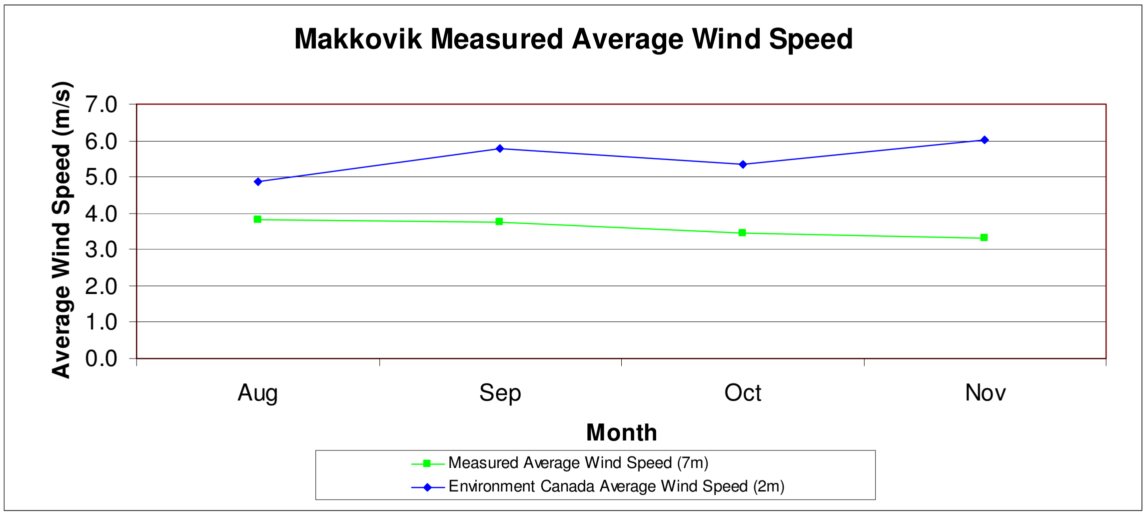

Makkovik Measured Wind Speed - October
Wind Speed (m/s)
Date
Wind Speed (10m)
Environment Canada Wind Speed (2m)

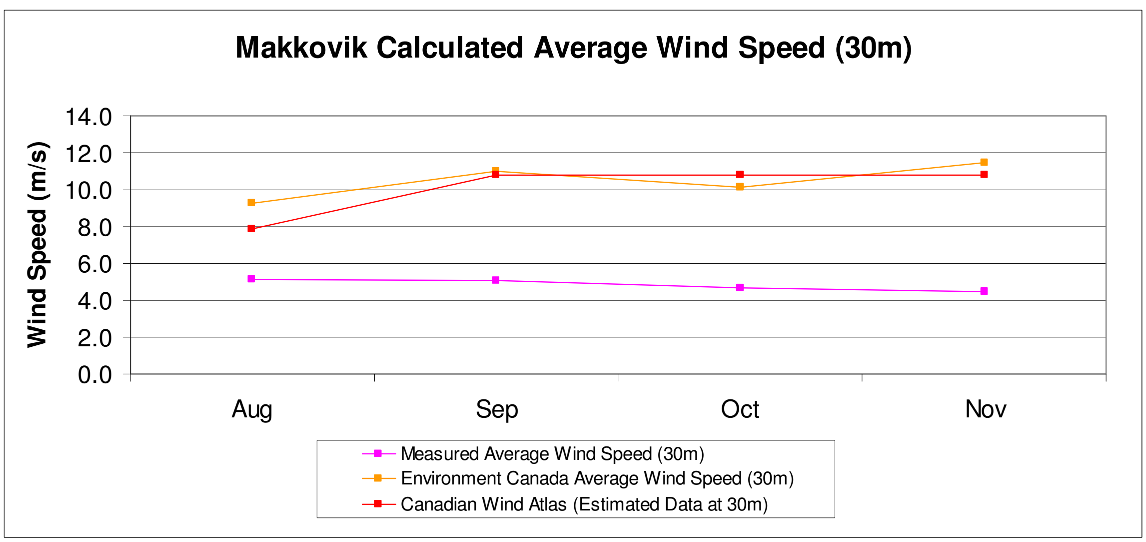

Makkovik Calculated Wind Speed - September
Wind Speed (m/s)
Date
Scaled Wind Speed (30m)
Environment Canada Wind Speed (30m)

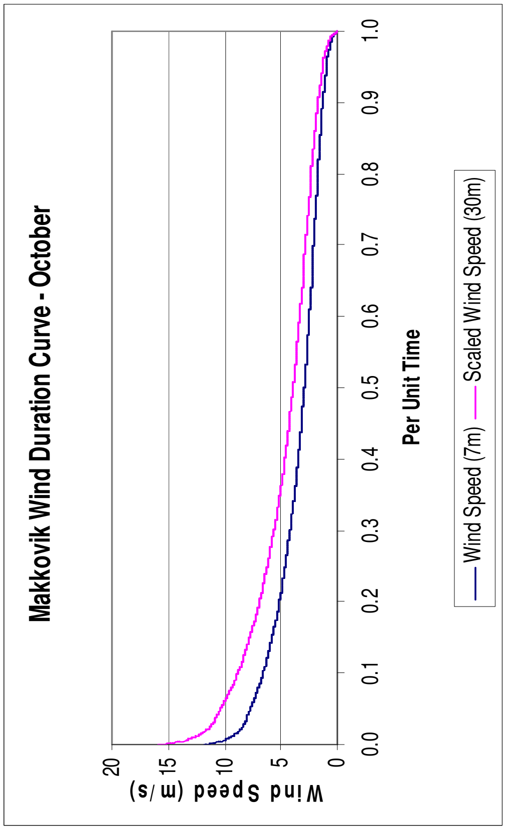

Makkovik Calculated Wind Speed - October
Wind Speed (m/s)
Date
Scaled Wind Speed (30m)
Environment Canada Wind Speed (30m)

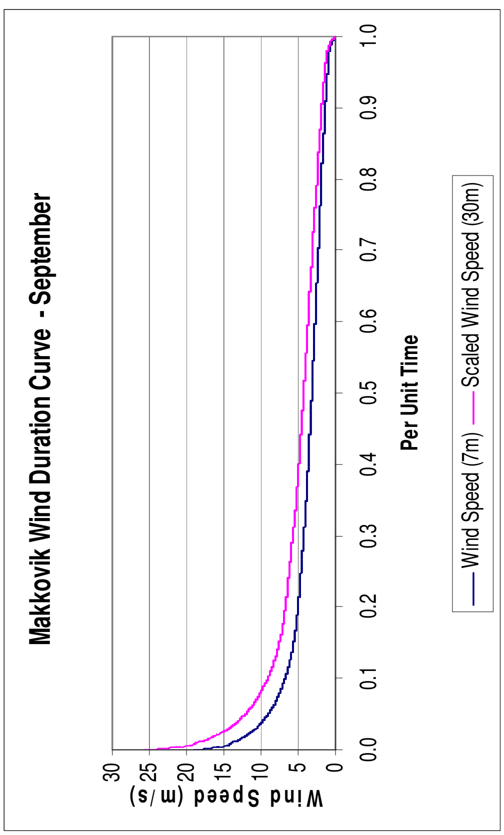

Makkovik Calculated Wind Speed - November
Wind Speed (m/s)
0
5
10
15
20
25
30
35
1 2 3 4 5 6 7 8 9 10 11 12 13 14 15 16 17 18 19 20 21 22 23 24 25 26 27 28 29 30
Date
Scaled Wind Speed (30m)
Environment Canada Wind Speed (30m)

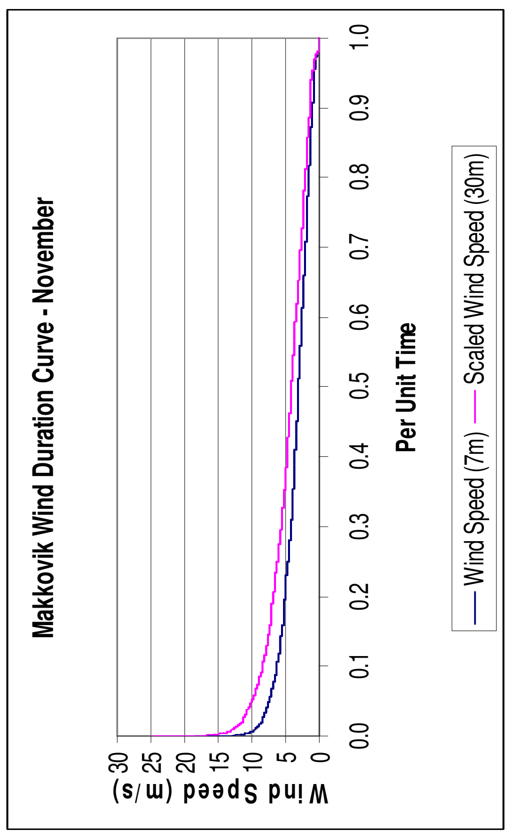

Makkovik Measured Wind Speed - November
Wind Speed (m/s)
0
5
10
15
20
1 2 3 4 5 6 7 8 9 10 11 12 13 14 15 16 17 18 19 20 21 22 23 24 25 26 27 28 29 30
Date
Wind Speed (10m)
Environment Canada Wind Speed (2m)

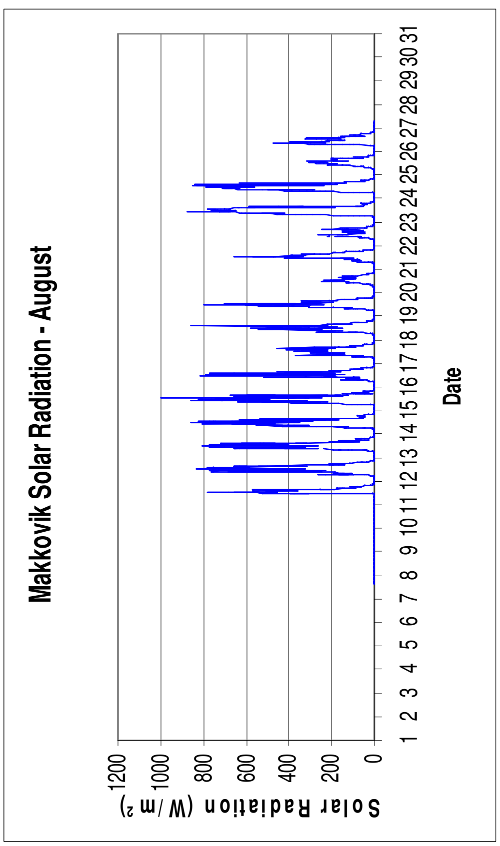

Makkovik Measured Average Wind Speed
Average Wind Speed (m/s)
7.0
6.0
5.0
4.0
3.0
2.0
1.0
0.0
Aug
Sep
Oct
Nov
Month
Measured Average Wind Speed (7m)
Environment Canada Average Wind Speed (2m)

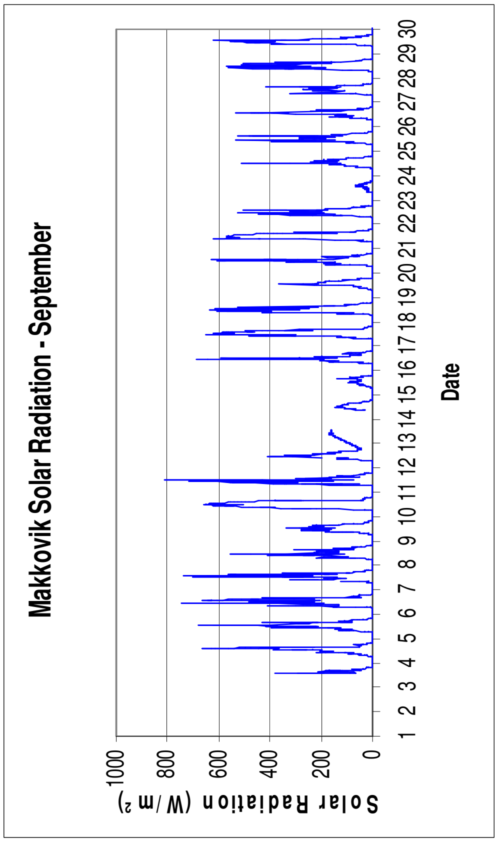

Makkovik Calculated Average Wind Speed (30m)
Wind Speed (m/s)
14.0
12.0
10.0
8.0
6.0
4.0
2.0
0.0
Aug
Sep
Oct
Nov
Measured Average Wind Speed (30m)
Environment Canada Average Wind Speed (30m)
Canadian Wind Atlas (Estimated Data at 30m)

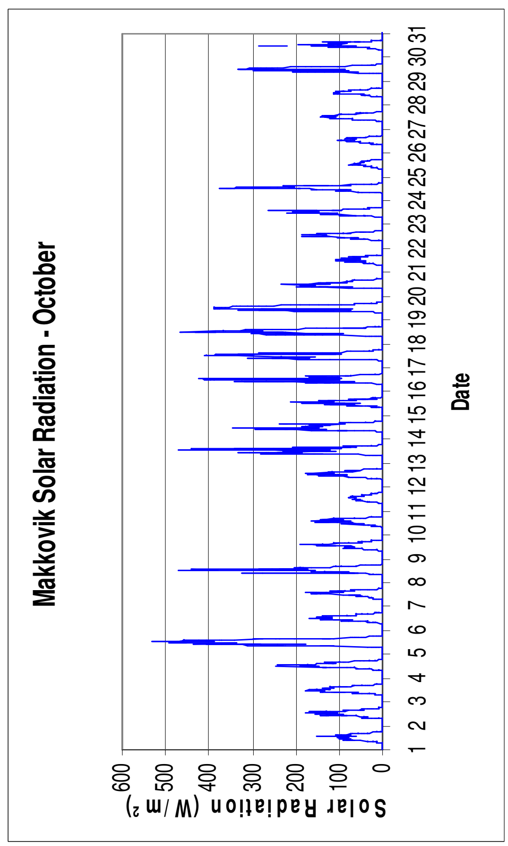

Makkovik Wind Duration Curve - October
Wind Speed (m/s)
20
15
10
5
0
0.0
0.1
0.2
0.3
0.4
0.5
0.6
0.7
0.8
0.9
1.0
Per Unit Time
Wind Speed (7m)
Scaled Wind Speed (30m)

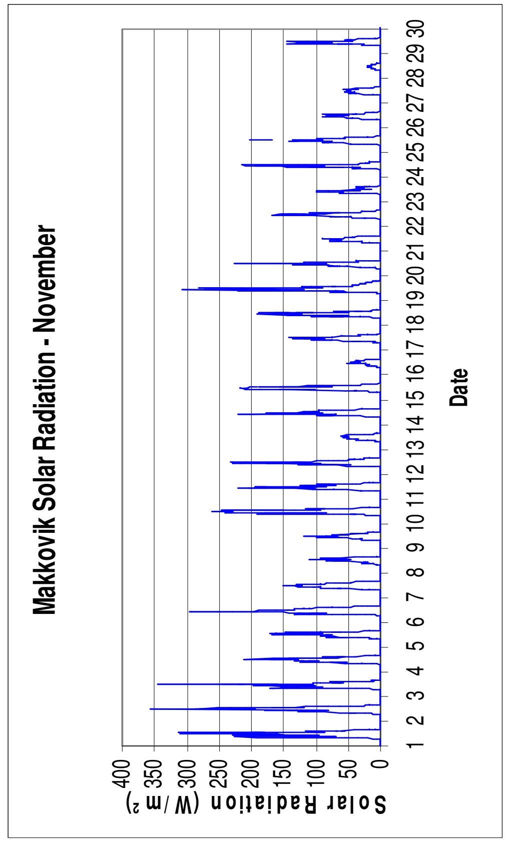

Makkovik Wind Duration Curve - September
Wind Speed (m/s)
30
25
20
15
10
5
0
0.0
0.1
0.2
0.3
0.4
0.5
0.6
0.7
0.8
0.9
1.0
Per Unit Time
Wind Speed (7m)
Scaled Wind Speed (30m)

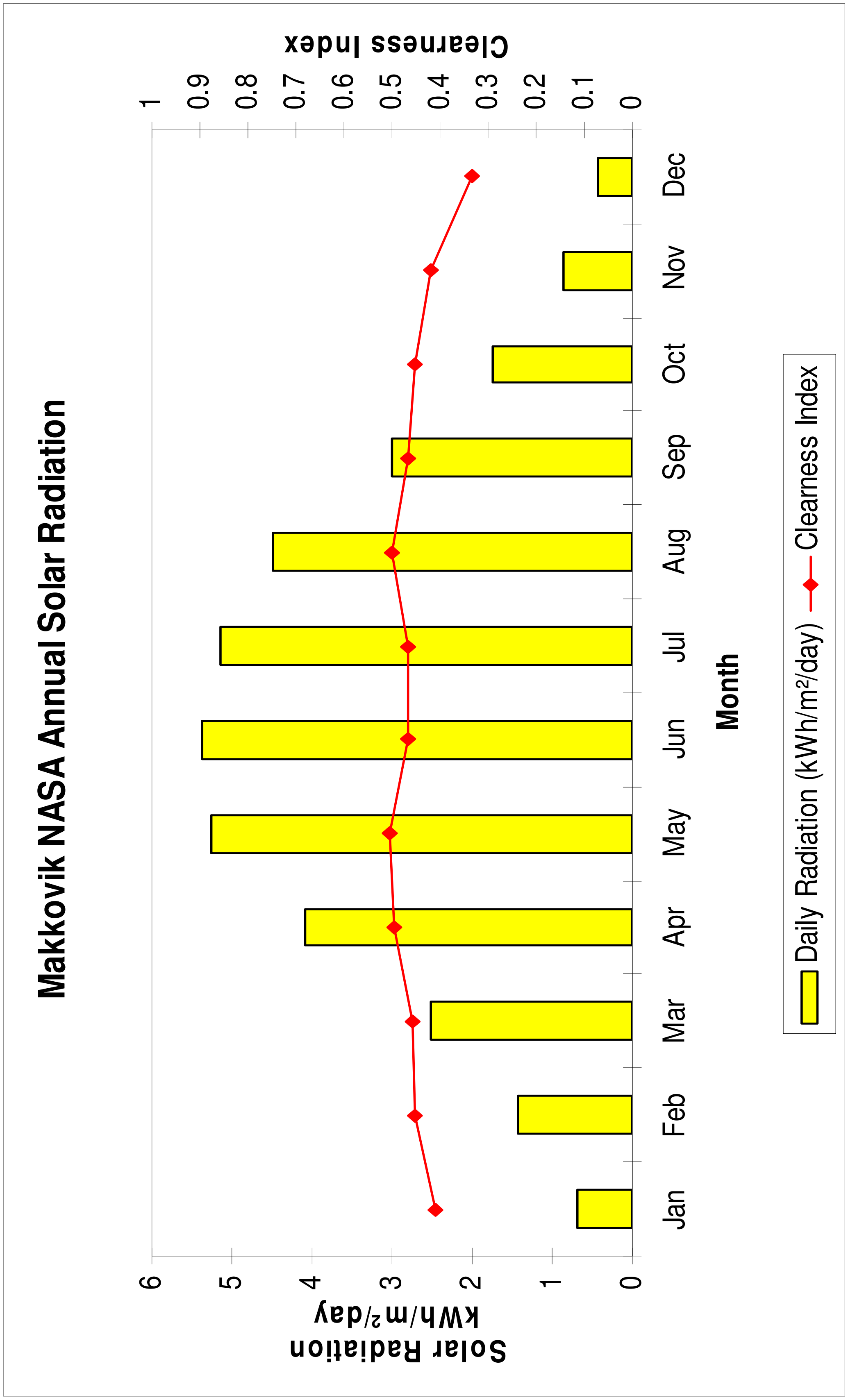

Makkovik Wind Duration Curve - November
Wind Speed (m/s)
30
25
20
15
10
5
0
0.0
0.1
0.2
0.3
0.4
0.5
0.6
0.7
0.8
0.9
1.0
Per Unit Time
Wind Speed (7m)
Scaled Wind Speed (30m)

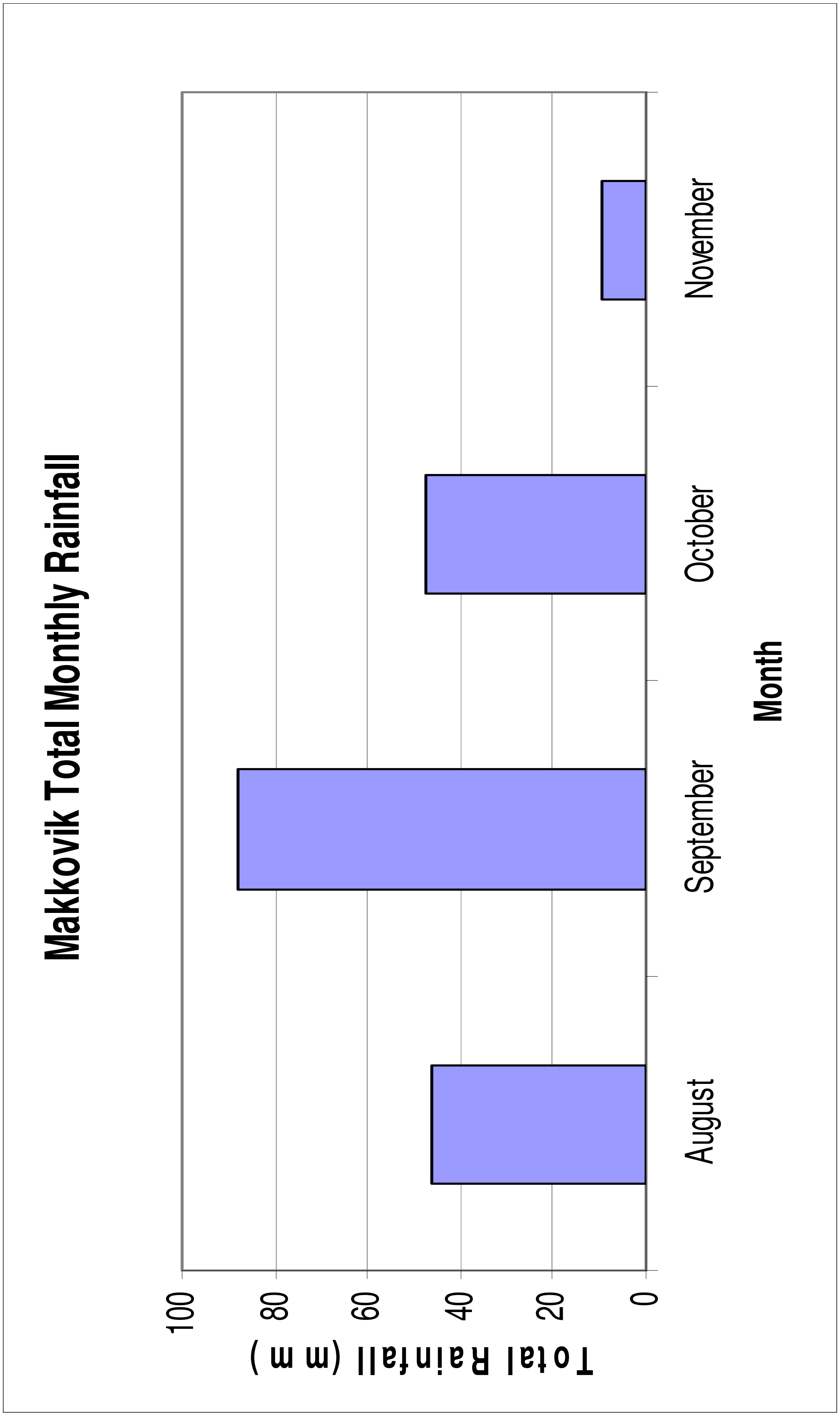

Makkovik Solar Radiation - August
Solar Radiation (W/m²)
0
200
400
600
800
1000
1200
1 2 3 4 5 6 7 8 9 10 11 12 13 14 15 16 17 18 19 20 21 22 23 24 25 26 27 28 29 30 31
Date


Makkovik Solar Radiation - September
Solar Radiation (W/m²)
0
200
400
600
800
1000
1 2 3 4 5 6 7 8 9 10 11 12 13 14 15 16 17 18 19 20 21 22 23 24 25 26 27 28 29 30
Date


Makkovik Solar Radiation - October
Solar Radiation (W/m²)
0
100
200
300
400
500
600
1 2 3 4 5 6 7 8 9 10 11 12 13 14 15 16 17 18 19 20 21 22 23 24 25 26 27 28 29 30 31
Date


Makkovik Solar Radiation - November
Solar Radiation (W/m²)
0
50
100
150
200
250
300
350
400
1 2 3 4 5 6 7 8 9 10 11 12 13 14 15 16 17 18 19 20 21 22 23 24 25 26 27 28 29 30
Date


Makkovik NASA Annual Solar Radiation
Solar Radiation
kWh/m²/day
0
1
2
3
4
5
6
Clearness Index
0
0.1
0.2
0.3
0.4
0.5
0.6
0.7
0.8
0.9
1
Jan
Feb
Mar
Apr
May
Jun
Jul
Aug
Sep
Oct
Nov
Dec
Month
Daily Radiation (kWh/m²/day)
Clearness Index

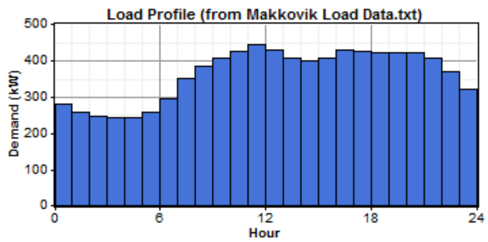

Makkovik Total Monthly Rainfall
Total Rainfall (m m)
0
20
40
60
80
100
August
September
October
November
Month

HOMER Input Summary

File name: Makkovik.hmr
File version: 2.67 beta
Author:

AC Load: Makkovik Net System Load

Data source: Makkovik Load Data.txt
Daily noise: 7.08%
Hourly noise: 8.85%
Scaled annual average: 9,205, 9,370, 9,504, 9,767, 9,885 kWh/d
Scaled peak load: 749, 763, 774, 795, 805 kW
Load factor: 0.512



PV

Size (kW)	Capital ($)	Replacement ($)	O&M ($/yr)
50.000	400,000	400,000	10,000
100.000	750,000	750,000	15,000

Sizes to consider: 0, 50, 100 kW
Lifetime: 20 yr
Derating factor: 80%
Tracking system: No Tracking
Slope: 55.1 deg
Azimuth: 0 deg
Ground reflectance: 20%

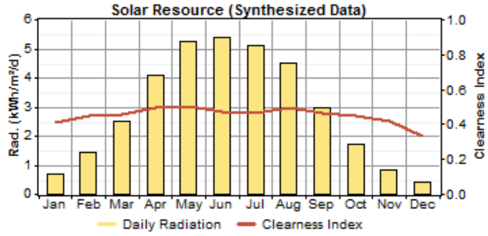
Solar Resource

Latitude: 55 degrees 4 minutes North
Longitude: 59 degrees 10 minutes West
Time zone: GMT -4:00

Data source: Synthetic

Month	Clearness Index	Average Radiation
		($kWh/m^2/day$)
Jan	0.408	0.700
Feb	0.452	1.420
Mar	0.458	2.510
Apr	0.497	4.090
May	0.505	5.270
Jun	0.469	5.380
Jul	0.469	5.130
Aug	0.498	4.500
Sep	0.467	2.990
Oct	0.453	1.730
Nov	0.420	0.850
Dec	0.331	0.440

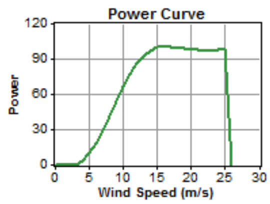
Scaled annual average: 2.91 $kWh/m^2/d$



AC Wind Turbine: Northern Power NW100/21

Quantity	Capital ($)	Replacement ($)	O&M ($/yr)
1	500,000	400,000	10,000

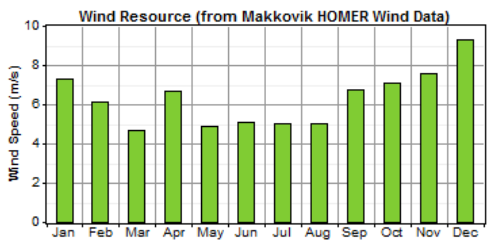
Quantities to consider: 0, 1, 2, 3, 4, 5, 6, 7, 8, 9, 10
Lifetime: 20 yr
Hub height: 37 m



Wind Resource

Data source: Makkovik HOMER Wind Data.txt

Month	Wind Speed (m/s)
Jan	7.32
Feb	6.11
Mar	4.66
Apr	6.72
May	4.93
Jun	5.11
Jul	5.00
Aug	5.06
Sep	6.75
Oct	7.12
Nov	7.55
Dec	9.29



Weibull k: 1.53
Autocorrelation factor: 0.854
Diurnal pattern strength: 0.0568
Hour of peak wind speed: 20
Scaled annual average: 6.3 m/s
Anemometer height: 7 m
Altitude: 10 m

Wind shear profile:	Logarithmic
Surface roughness length:	0.2 m

AC Hydro:

Capital cost:	$ 2,222,000, 8,068,000, 3,858,000, 6,548,000
Replacement cost:	$ 0
O&M cost:	$ 17,160, 47,890, 15,890, 14,840/yr
Lifetime:	60 yr
Available head:	25, 99, 31, 34 m
Design flow rate:	1,140, 800, 850, 720 L/s
Min. flow ratio:	15, 10, 15, 15%
Max. flow ratio:	100%
Turbine efficiency:	85%
Pipe head loss:	0%

Consider systems without hydro: Yes

Hydro Resource

Data source: Synthetic

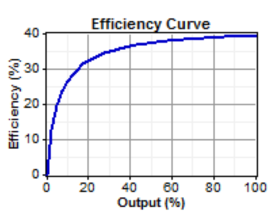
Month	Stream Flow (L/s)
Jan	235
Feb	165
Mar	153
Apr	212
May	582
Jun	565
Jul	582
Aug	582
Sep	565
Oct	582
Nov	565
Dec	347

Residual flow:	0 L/s
Scaled annual average:	153, 428, 141, 131 L/s

AC Generator: 3033

Size (kW)	Capital ($)	Replacement ($)	O&M ($/hr)
450.000	0	400,000	1.684

Sizes to consider:	450 kW
Lifetime:	100,000 hrs
Min. load ratio:	30%
Heat recovery ratio:	0%
Fuel used:	#1 Diesel Arctic Grade
Fuel curve intercept:	0.0133 L/hr/kW
Fuel curve slope:	0.233 L/hr/kW

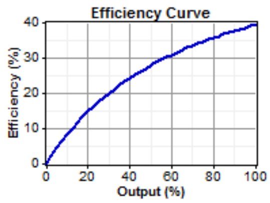


AC Generator: 2029

Size (kW)	Capital ($)	Replacement ($)	O&M ($/hr)

620.000	0	600,000	1.850

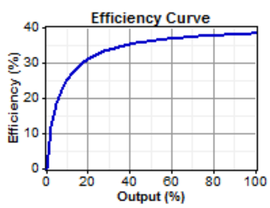
Sizes to consider: 620 kW
Lifetime: 100,000 hrs
Min. load ratio: 30%
Heat recovery ratio: 0%
Fuel used: #1 Diesel Arctic Grade
Fuel curve intercept: 0.102 L/hr/kW
Fuel curve slope: 0.144 L/hr/kW



AC Generator: 2059

Size (kW)	Capital ($)	Replacement ($)	O&M ($/hr)
635.000	0	600,000	1.850

Sizes to consider: 635 kW
Lifetime: 100,000 hrs
Min. load ratio: 30%
Heat recovery ratio: 0%
Fuel used: #1 Diesel Arctic Grade
Fuel curve intercept: 0.0146 L/hr/kW
Fuel curve slope: 0.239 L/hr/kW



Fuel: #1 Diesel Arctic Grade

Price: $ 0.921, 0.920, 0.940, 0.969, 0.969/L
Lower heating value: 45.8 MJ/kg
Density: 809 kg/m3
Carbon content: 88.0%
Sulfur content: 0.0500%

Converter

Size (kW)	Capital ($)	Replacement ($)	O&M ($/yr)
100.000	64,000	64,000	6,400

Sizes to consider: 0, 100 kW
Lifetime: 15 yr
Inverter efficiency: 90%
Inverter can parallel with AC generator: Yes
Rectifier relative capacity: 100%
Rectifier efficiency: 85%

Economics

Annual real interest rate: 8%
Project lifetime: 60 yr
Capacity shortage penalty: $ 0/kWh
System fixed capital cost: $ 0

System fixed O&M cost: $ 0/yr

Generator control

Check load following: Yes
Check cycle charging: No

Allow systems with multiple generators:	Yes
Allow multiple generators to operate simultaneously:	Yes
Allow systems with generator capacity less than peak load:	No

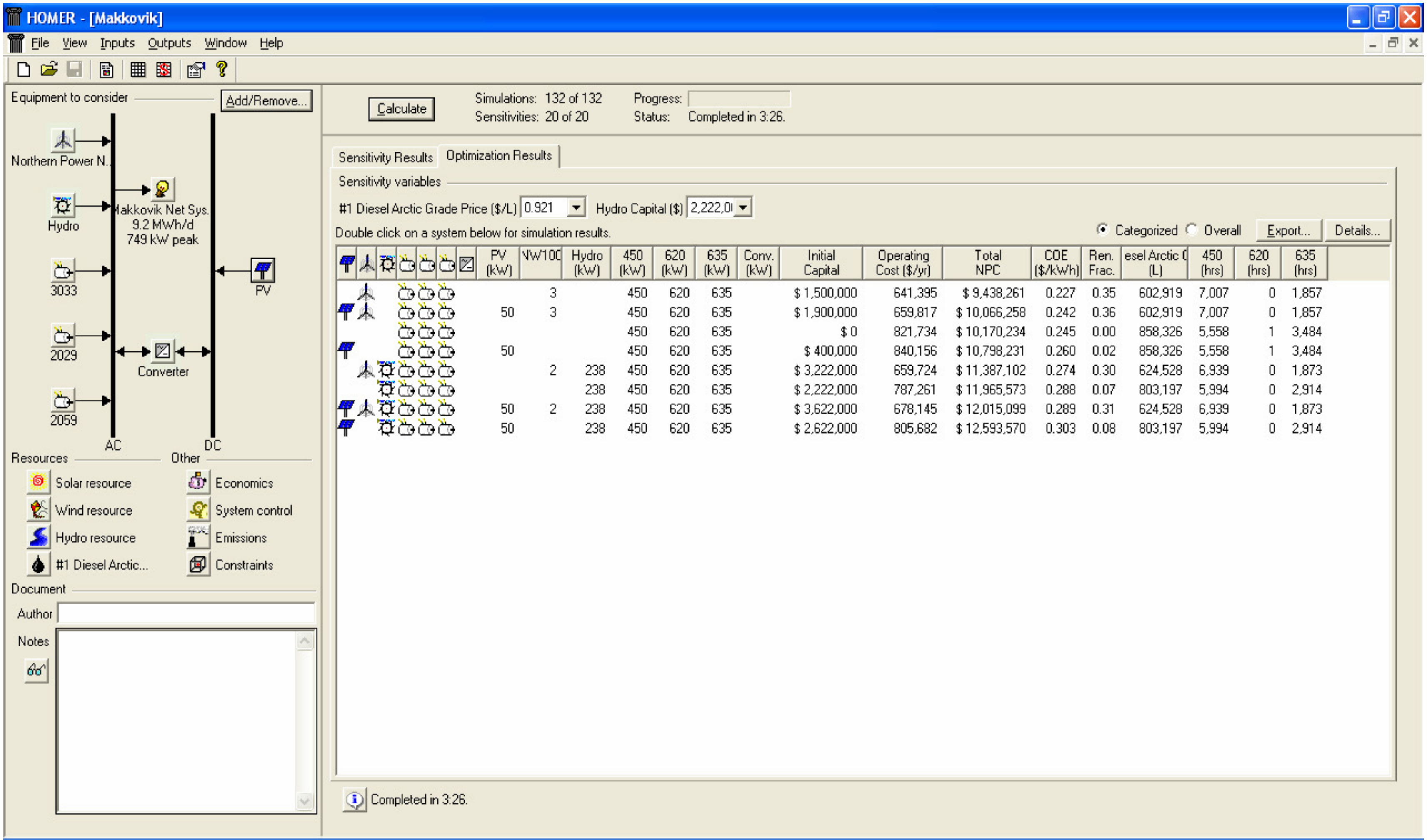
Emissions

Carbon dioxide penalty:	$ 0/t
Carbon monoxide penalty:	$ 0/t
Unburned hydrocarbons penalty:	$ 0/t
Particulate matter penalty:	$ 0/t
Sulfur dioxide penalty:	$ 0/t
Nitrogen oxides penalty:	$ 0/t

Constraints

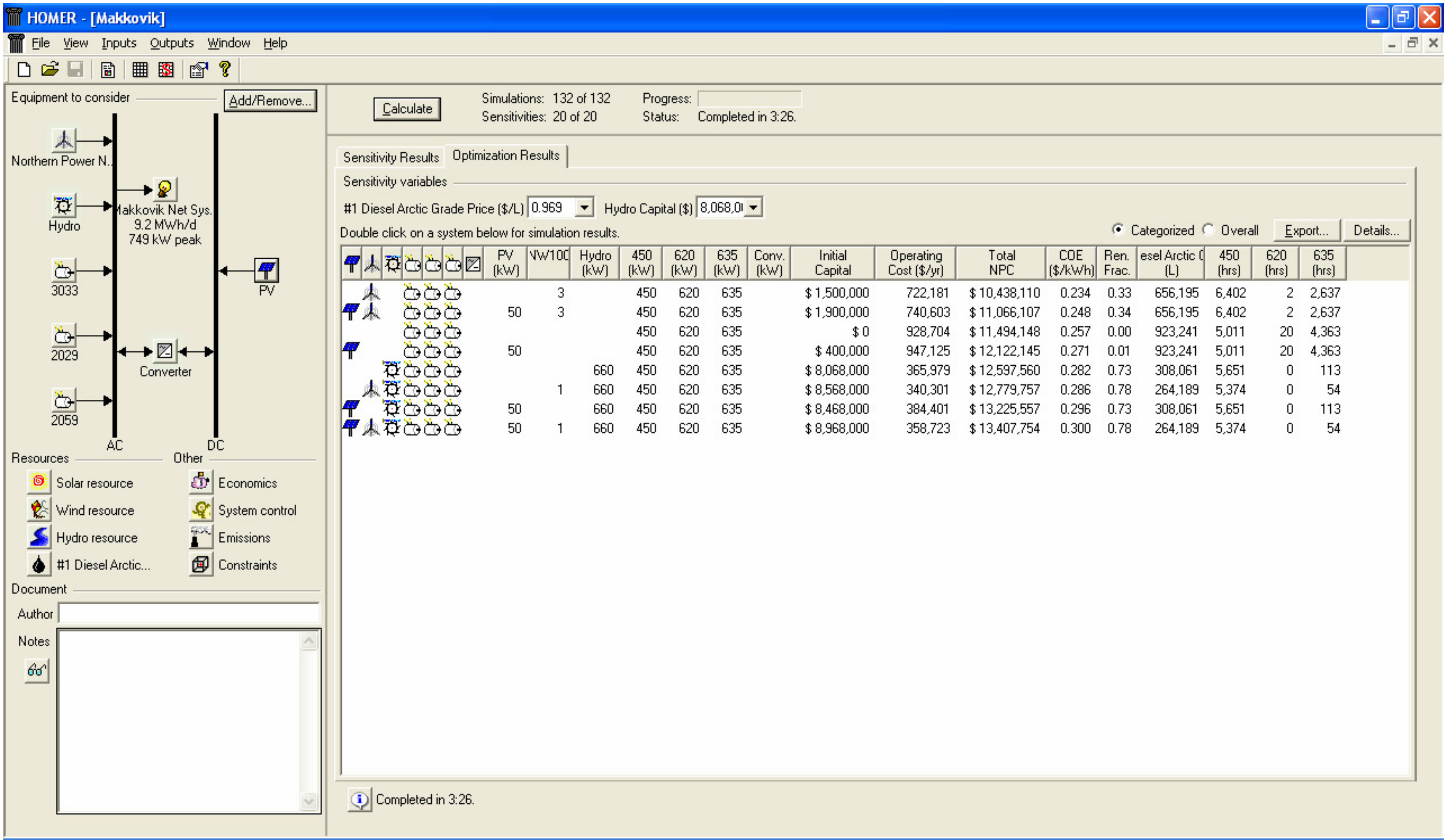
Maximum annual capacity shortage:	0%
Minimum renewable fraction:	0%

Operating reserve as percentage of hourly load:	10%
Operating reserve as percentage of peak load:	0%
Operating reserve as percentage of solar power output:	25%
Operating reserve as percentage of wind power output:	50%



PV (kW)	NW100	Hydro (kW)	450 (kW)	620 (kW)	635 (kW)	Conv. (kW)	Initial Capital	Operating Cost ($/yr)	Total NPC	COE ($/kWh)	Ren. Frac.	esel Arctic ((L)	450 (hrs)	620 (hrs)	635 (hrs)
	3		450	620	635		$ 1,500,000	641,395	$ 9,438,261	0.227	0.35	602,919	7,007	0	1,857
50	3		450	620	635		$ 1,900,000	659,817	$ 10,066,258	0.242	0.36	602,919	7,007	0	1,857
			450	620	635		$ 0	821,734	$ 10,170,234	0.245	0.00	858,326	5,558	1	3,484
50			450	620	635		$ 400,000	840,156	$ 10,798,231	0.260	0.02	858,326	5,558	1	3,484
	2	238	450	620	635		$ 3,222,000	659,724	$ 11,387,102	0.274	0.30	624,528	6,939	0	1,873
		238	450	620	635		$ 2,222,000	787,261	$ 11,965,573	0.288	0.07	803,197	5,994	0	2,914
50	2	238	450	620	635		$ 3,622,000	678,145	$ 12,015,099	0.289	0.31	624,528	6,939	0	1,873
50		238	450	620	635		$ 2,622,000	805,682	$ 12,593,570	0.303	0.08	803,197	5,994	0	2,914

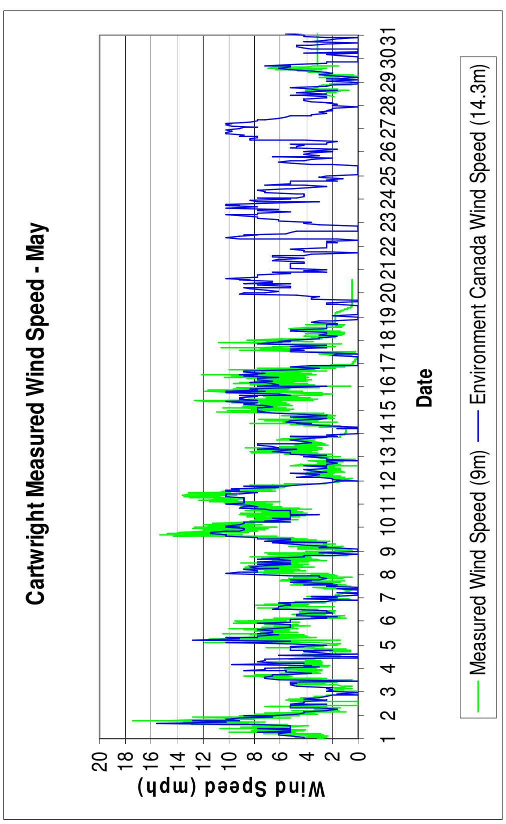
Makkovik HOMER Results – 2011 System Load

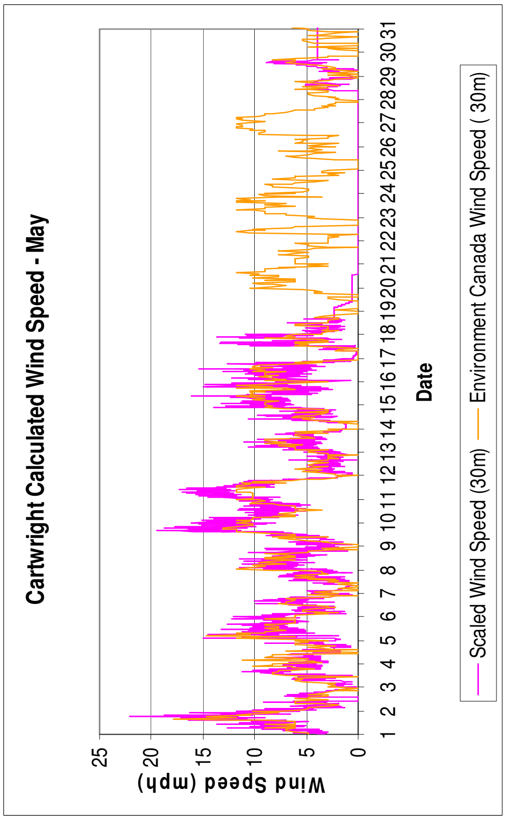


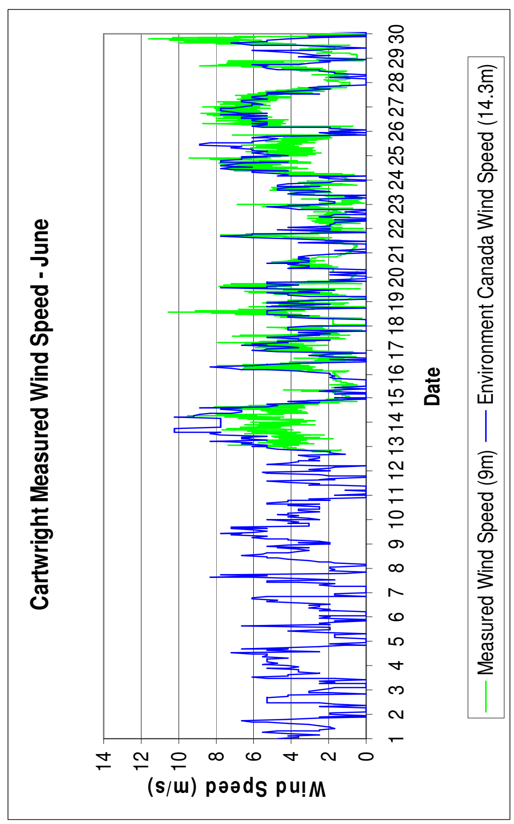
PV (kW)	NW100	Hydro (kW)	450 (kW)	620 (kW)	635 (kW)	Conv. (kW)	Initial Capital	Operating Cost ($/yr)	Total NPC	COE ($/kWh)	Ren. Frac.	Diesel Arctic (L)	450 (hrs)	620 (hrs)	635 (hrs)
	3		450	620	635		$ 1,500,000	722,181	$ 10,438,110	0.234	0.33	656,195	6,402	2	2,637
50	3		450	620	635		$ 1,900,000	740,603	$ 11,066,107	0.248	0.34	656,195	6,402	2	2,637
			450	620	635		$ 0	928,704	$ 11,494,148	0.257	0.00	923,241	5,011	20	4,363
50			450	620	635		$ 400,000	947,125	$ 12,122,145	0.271	0.01	923,241	5,011	20	4,363
		660	450	620	635		$ 8,068,000	365,979	$ 12,597,560	0.282	0.73	308,061	5,651	0	113
	1	660	450	620	635		$ 8,568,000	340,301	$ 12,779,757	0.286	0.78	264,189	5,374	0	54
50		660	450	620	635		$ 8,468,000	384,401	$ 13,225,557	0.296	0.73	308,061	5,651	0	113
50	1	660	450	620	635		$ 8,968,000	358,723	$ 13,407,754	0.300	0.78	264,189	5,374	0	54

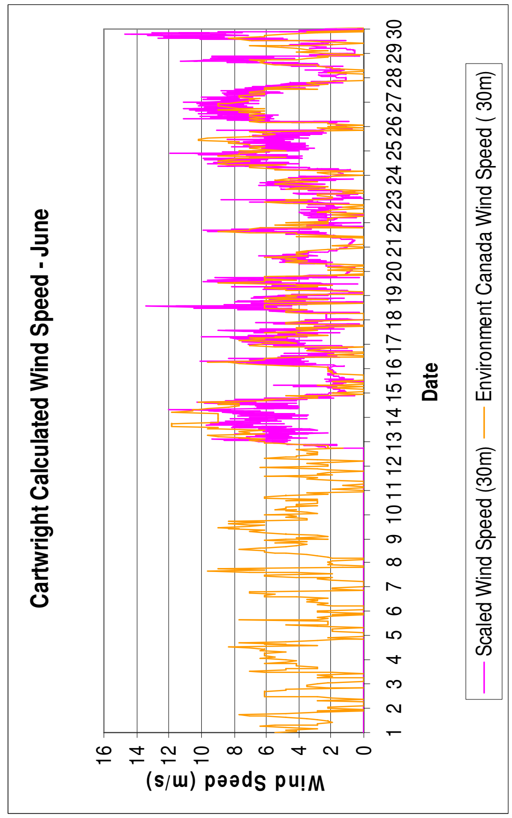
Makkovik HOMER Results – 2015 System Load

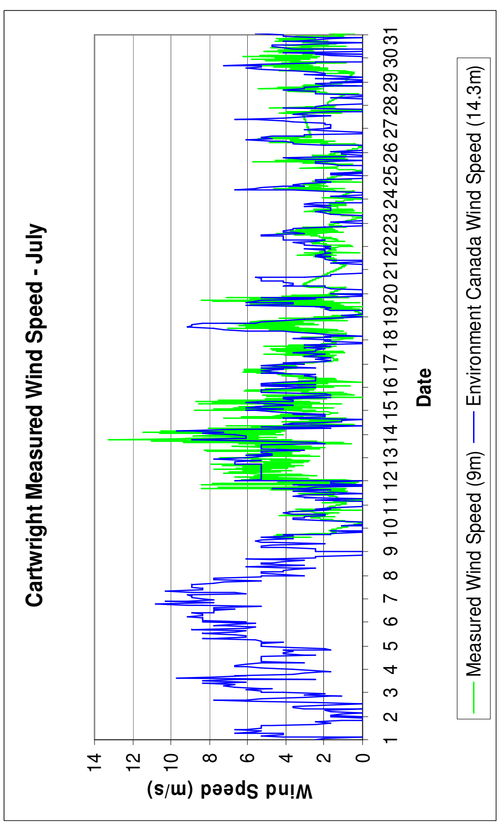
APPENDIX D - CARTWRIGHT

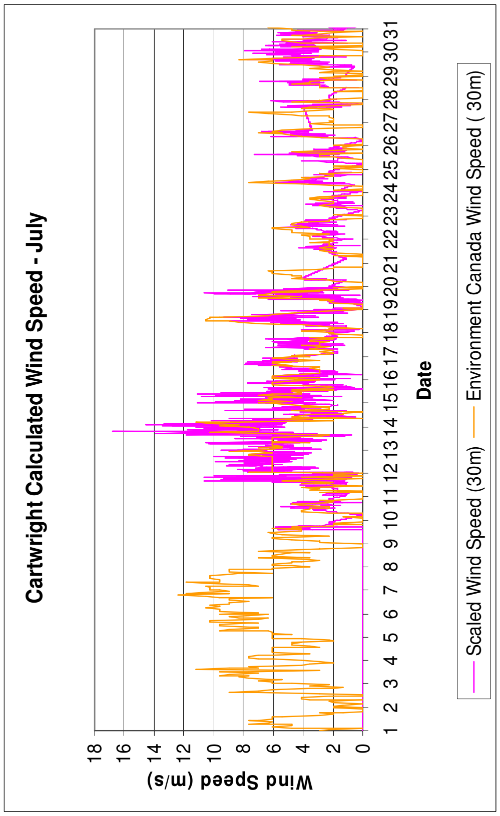

Cartwright Measured Wind Speed - May
Wind Speed (mph)
0 2 4 6 8 10 12 14 16 18 20
1 2 3 4 5 6 7 8 9 10 11 12 13 14 15 16 17 18 19 20 21 22 23 24 25 26 27 28 29 30 31
Date
Measured Wind Speed (9m)
Environment Canada Wind Speed (14.3m)

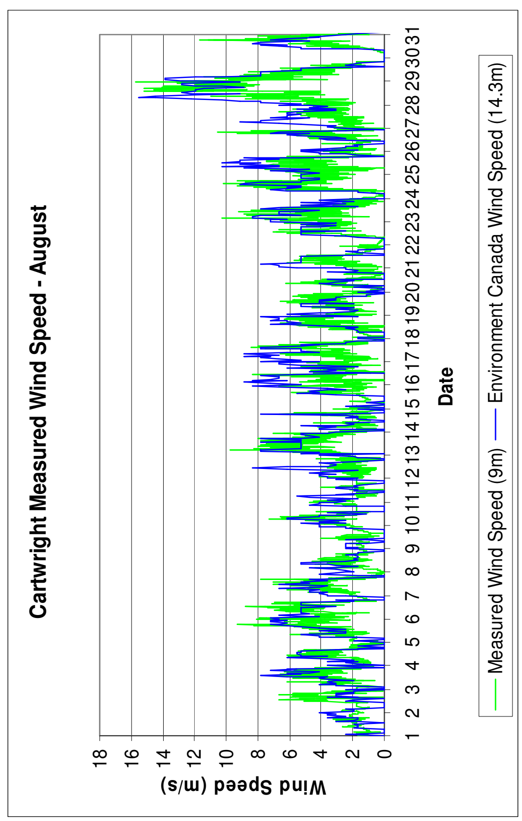

Cartwright Calculated Wind Speed - May
Wind Speed (mph)
0 5 10 15 20 25
1 2 3 4 5 6 7 8 9 10 11 12 13 14 15 16 17 18 19 20 21 22 23 24 25 26 27 28 29 30 31
Date
Scaled Wind Speed (30m)
Environment Canada Wind Speed (30m)

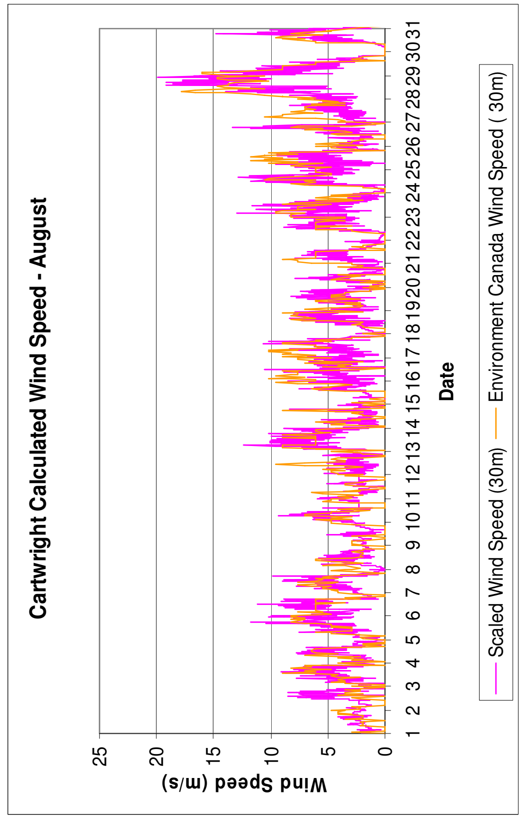

Cartwright Measured Wind Speed - June
Wind Speed (m/s)
0 2 4 6 8 10 12 14
1 2 3 4 5 6 7 8 9 10 11 12 13 14 15 16 17 18 19 20 21 22 23 24 25 26 27 28 29 30
Date
Measured Wind Speed (9m)
Environment Canada Wind Speed (14.3m)

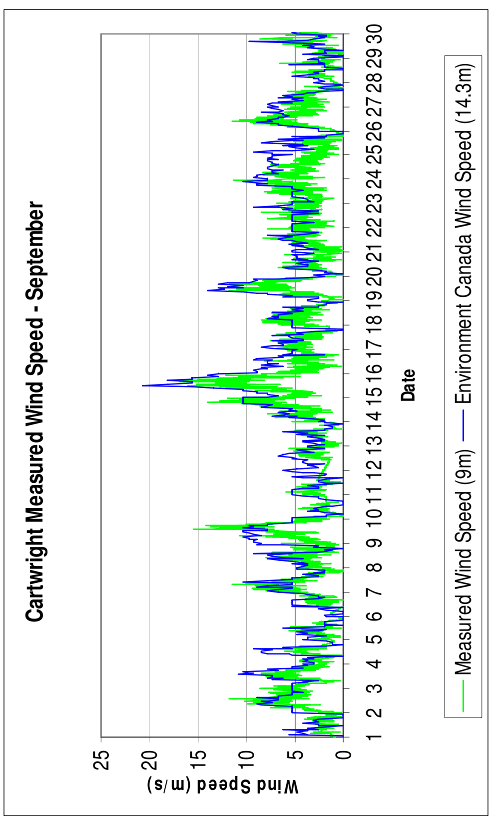

Cartwright Calculated Wind Speed - June
Wind Speed (m/s)
0 2 4 6 8 10 12 14 16
1 2 3 4 5 6 7 8 9 10 11 12 13 14 15 16 17 18 19 20 21 22 23 24 25 26 27 28 29 30
Date
Scaled Wind Speed (30m)
Environment Canada Wind Speed (30m)

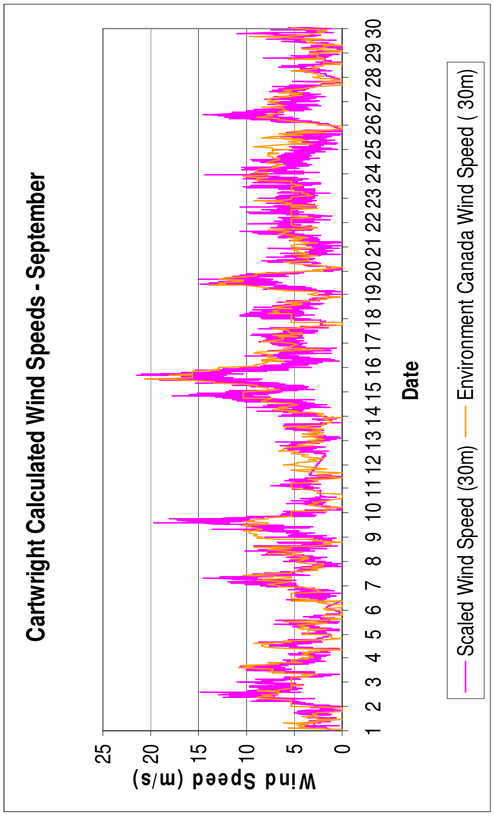

Cartwright Measured Wind Speed - July
Wind Speed (m/s)
Date
Measured Wind Speed (9m)
Environment Canada Wind Speed (14.3m)

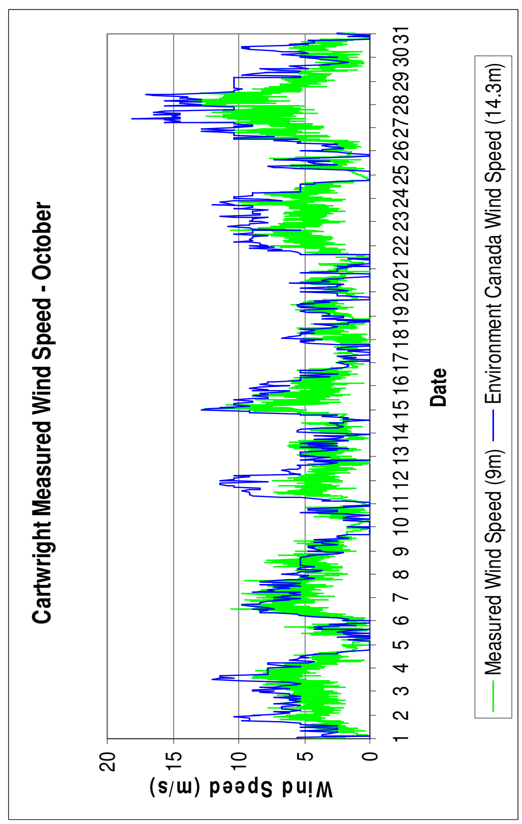

Cartwright Calculated Wind Speed - July
Wind Speed (m/s)
Date
Scaled Wind Speed (30m)
Environment Canada Wind Speed (30m)

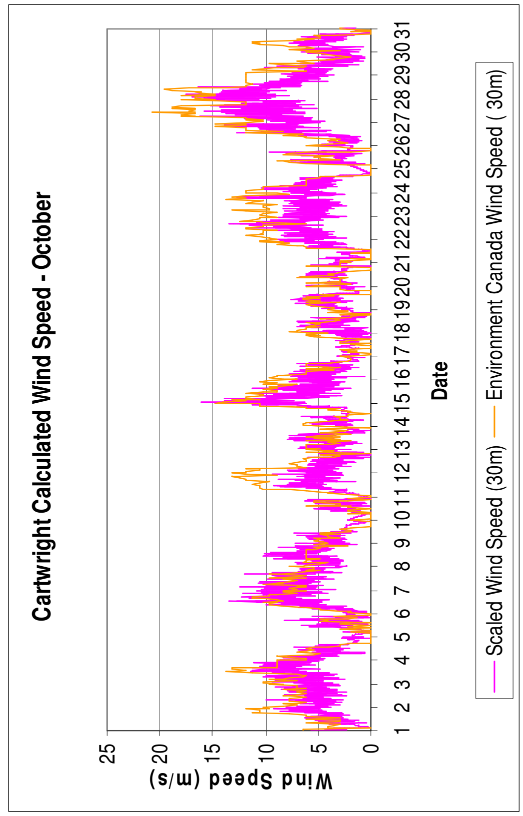

Cartwright Measured Wind Speed - August
Wind Speed (m/s)
Date
Measured Wind Speed (9m)
Environment Canada Wind Speed (14.3m)

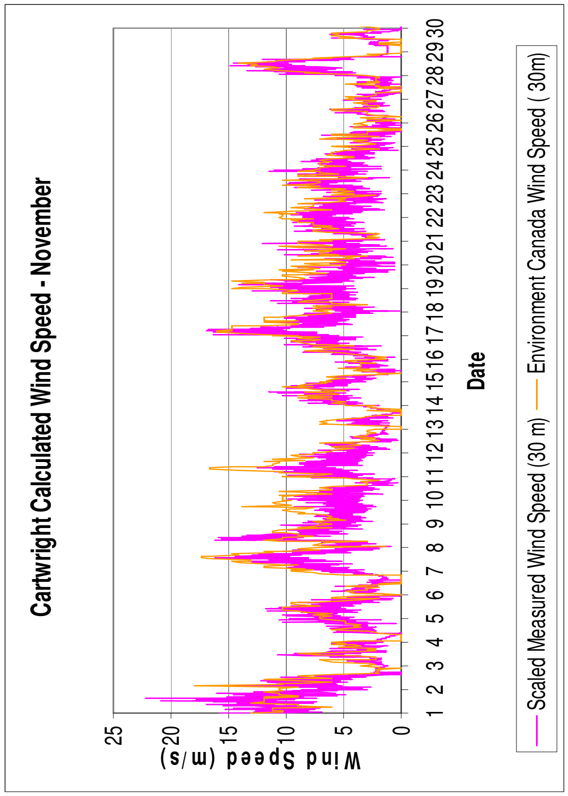

Cartwright Calculated Wind Speed - August
Wind Speed (m/s)
Date
Scaled Wind Speed (30m)
Environment Canada Wind Speed (30m)

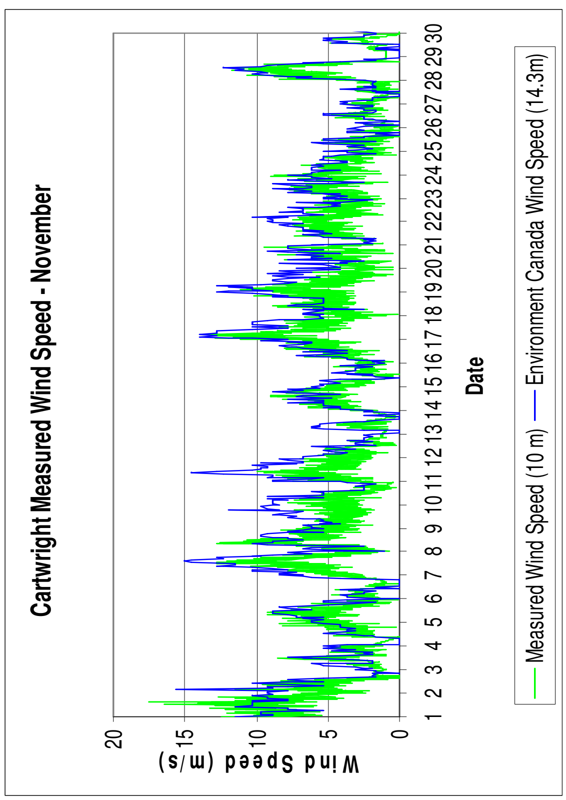

Cartwright Measured Wind Speed - September
Wind Speed (m/s)
Date
Measured Wind Speed (9m)
Environment Canada Wind Speed (14.3m)

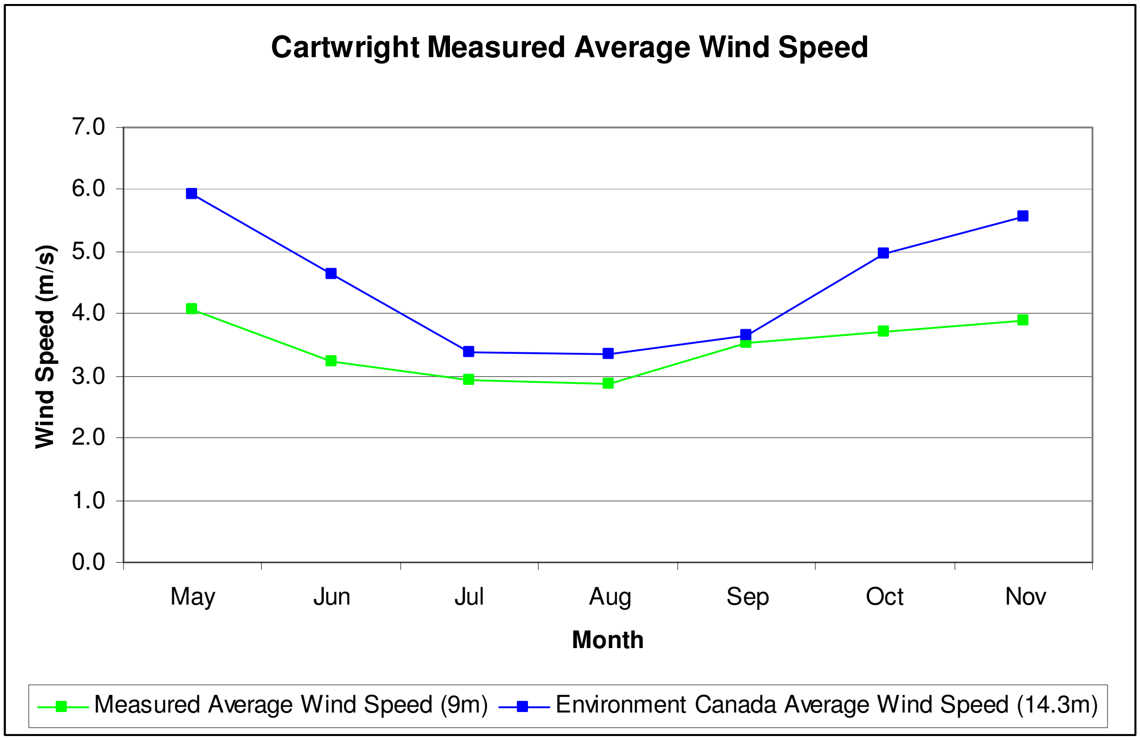

Cartwright Calculated Wind Speeds - September
Wind Speed (m/s)
Date
Scaled Wind Speed (30m)
Environment Canada Wind Speed (30m)

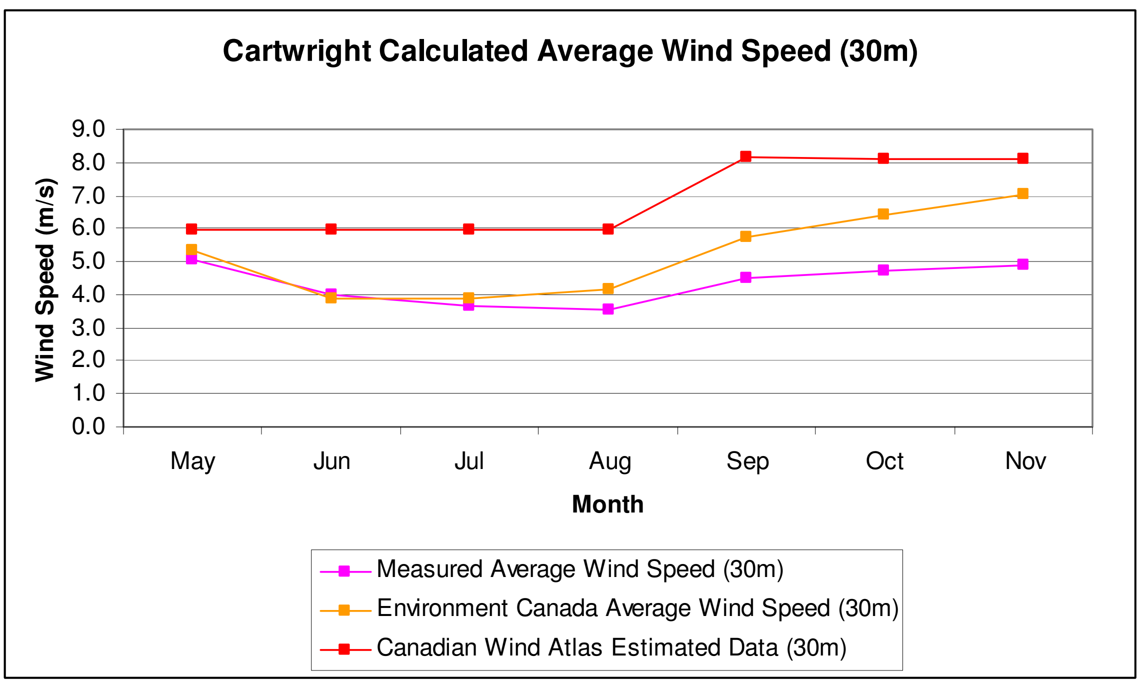

Cartwright Measured Wind Speed - October
Wind Speed (m/s)
Date
Measured Wind Speed (9m)
Environment Canada Wind Speed (14.3m)

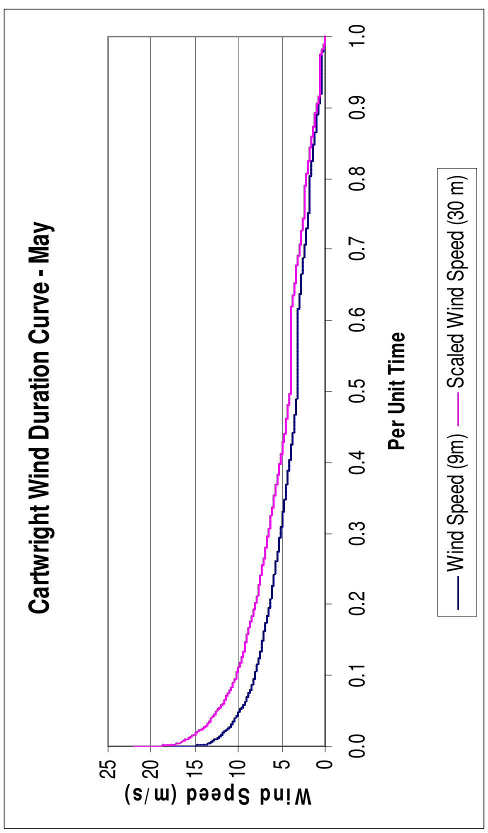

Cartwright Calculated Wind Speed - October
Wind Speed (m/s)
Date
Scaled Wind Speed (30m)
Environment Canada Wind Speed (30m)

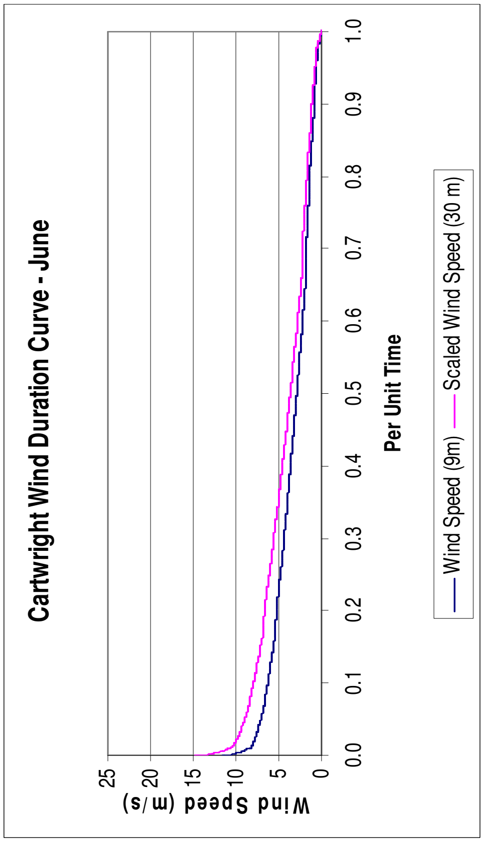

Cartwright Calculated Wind Speed - November
Wind Speed (m/s)
25
20
15
10
5
0
1 2 3 4 5 6 7 8 9 10 11 12 13 14 15 16 17 18 19 20 21 22 23 24 25 26 27 28 29 30
Date
Scaled Measured Wind Speed (30 m)
Environment Canada Wind Speed (30m)

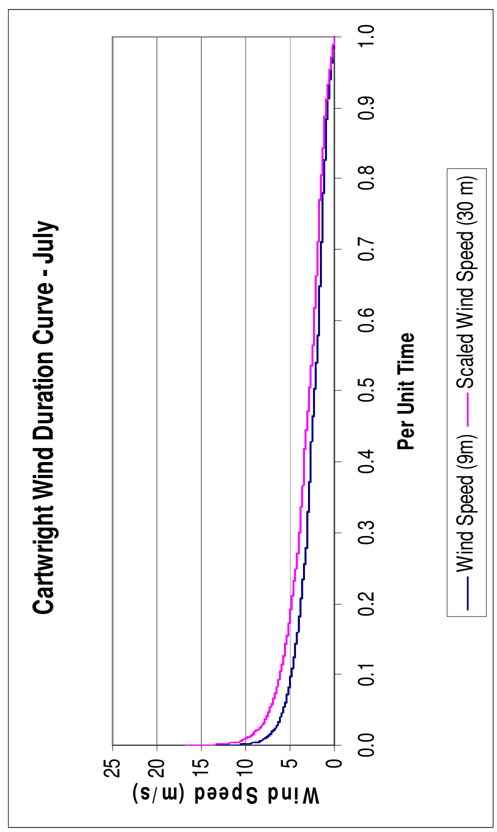

Cartwright Measured Wind Speed - November
Wind Speed (m/s)
20
15
10
5
0
1 2 3 4 5 6 7 8 9 10 11 12 13 14 15 16 17 18 19 20 21 22 23 24 25 26 27 28 29 30
Date
Measured Wind Speed (10 m)
Environment Canada Wind Speed (14.3m)

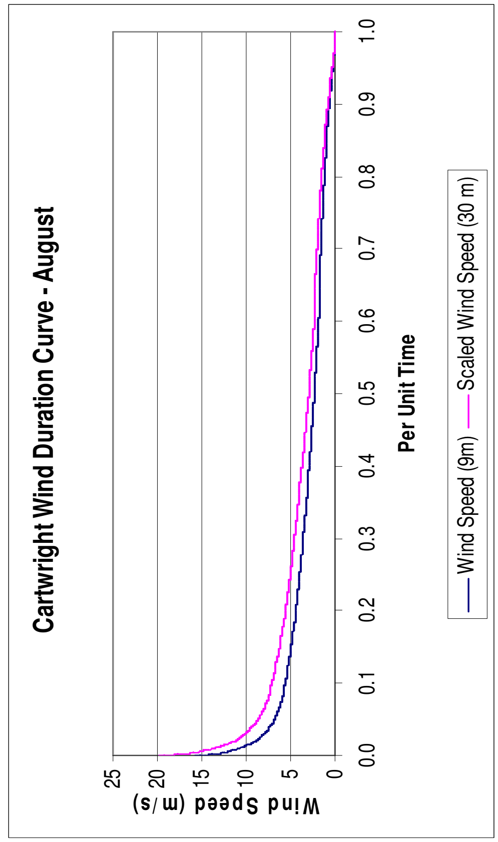

Cartwright Measured Average Wind Speed
7.0
6.0
5.0
4.0
3.0
2.0
1.0
0.0
Wind Speed (m/s)
May
Jun
Jul
Aug
Sep
Oct
Nov
Month
Measured Average Wind Speed (9m)
Environment Canada Average Wind Speed (14.3m)

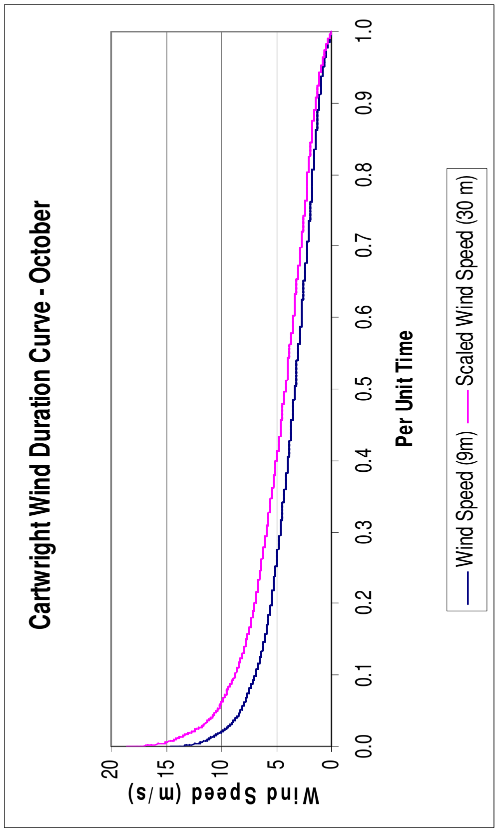

Cartwright Calculated Average Wind Speed (30m)
9.0
8.0
7.0
6.0
5.0
4.0
3.0
2.0
1.0
0.0
Wind Speed (m/s)
May
Jun
Jul
Aug
Sep
Oct
Nov
Month
Measured Average Wind Speed (30m)
Environment Canada Average Wind Speed (30m)
Canadian Wind Atlas Estimated Data (30m)

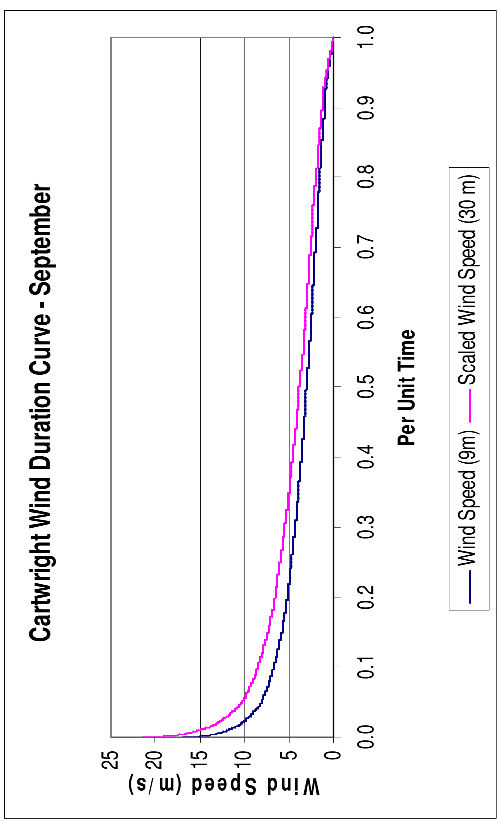

Cartwright Wind Duration Curve - May
Wind Speed (m/s)
Per Unit Time
Wind Speed (9m)
Scaled Wind Speed (30 m)

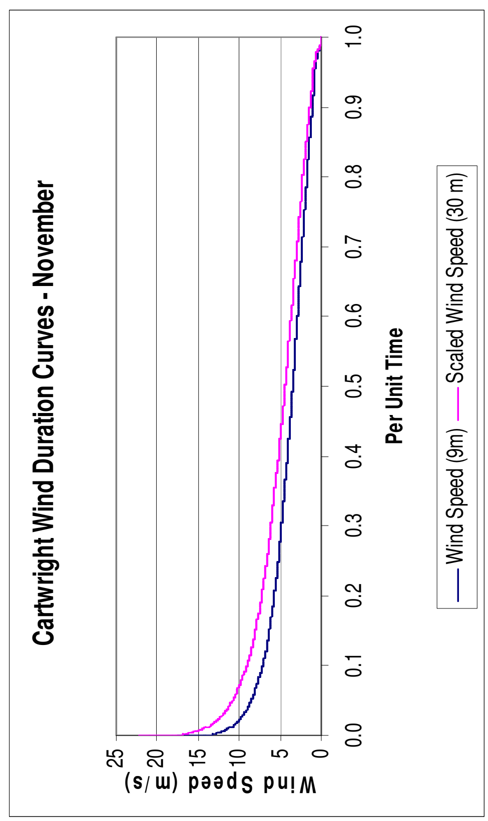

Cartwright Wind Duration Curve - June
Wind Speed (m/s)
Per Unit Time
Wind Speed (9m)
Scaled Wind Speed (30 m)

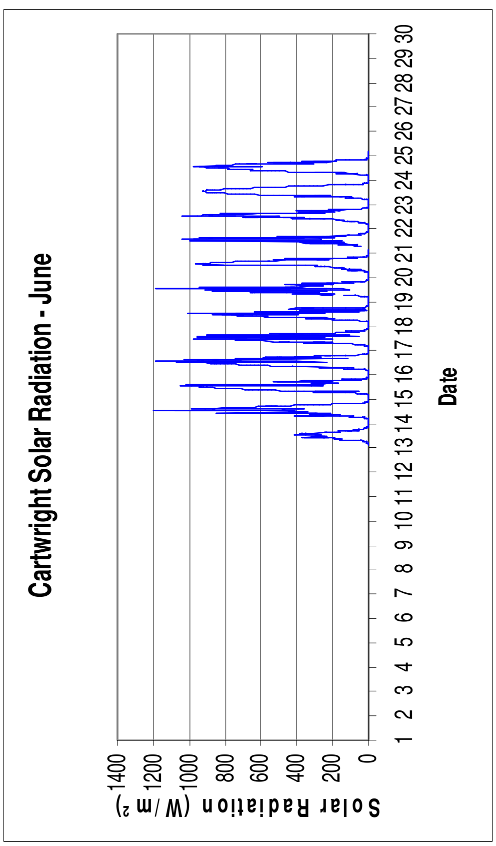

Cartwright Wind Duration Curve - July
Wind Speed (m/s)
Per Unit Time
Wind Speed (9m)
Scaled Wind Speed (30 m)

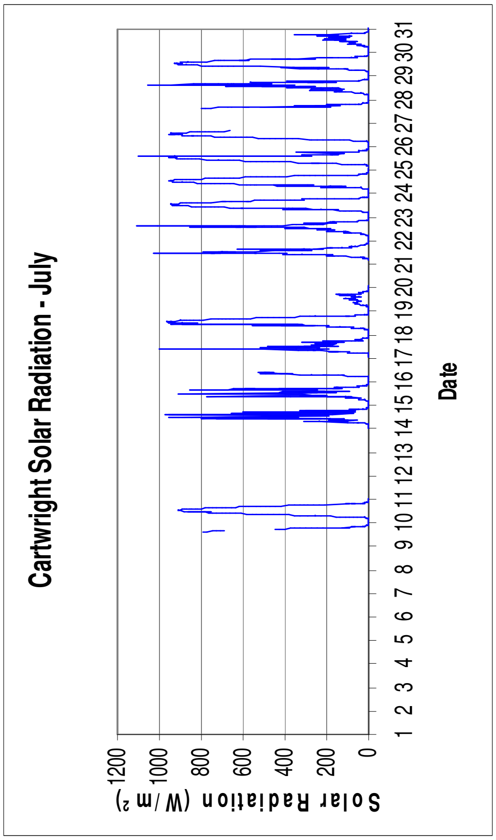

Cartwright Wind Duration Curve - August
Wind Speed (m/s)
Per Unit Time
Wind Speed (9m)
Scaled Wind Speed (30 m)

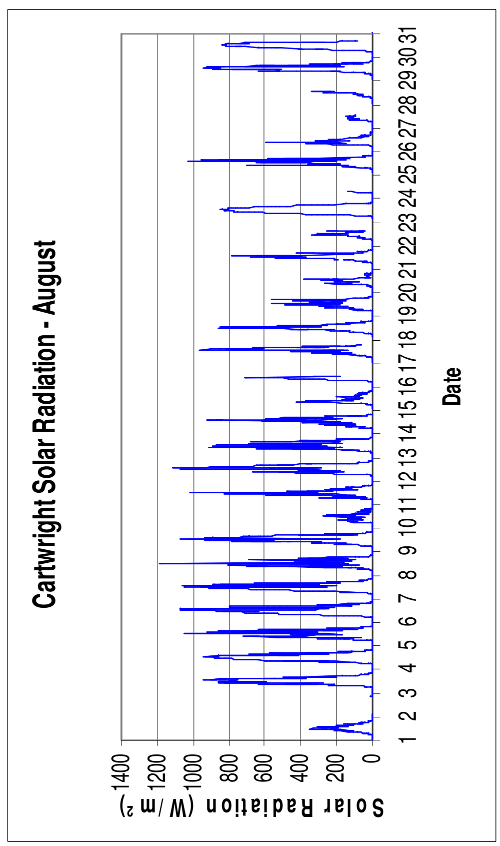

Cartwright Wind Duration Curve - October
Wind Speed (m/s)
Per Unit Time
Wind Speed (9m)
Scaled Wind Speed (30 m)

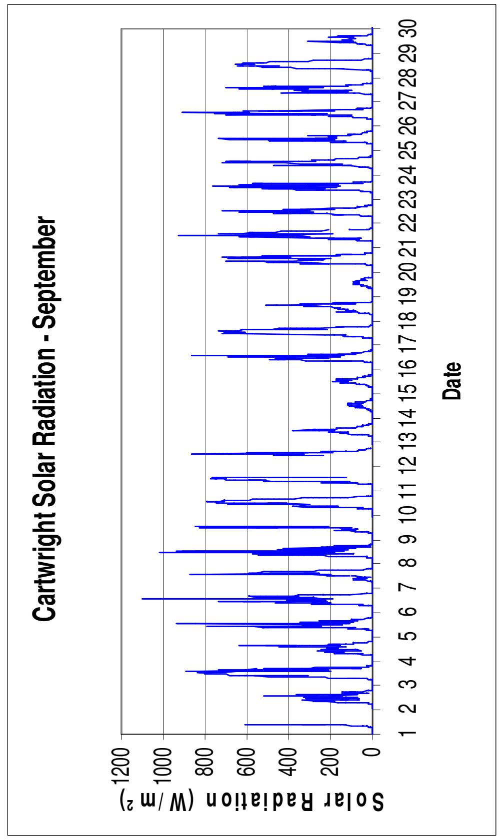

Cartwright Wind Duration Curve - September
Wind Speed (m/s)
Per Unit Time
Wind Speed (9m)
Scaled Wind Speed (30 m)

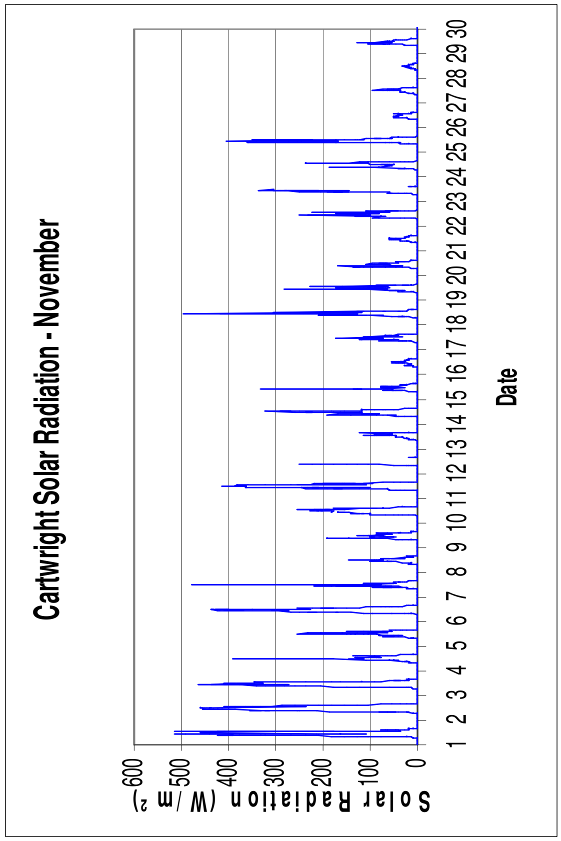

Cartwright Wind Duration Curves - November
Wind Speed (m/s)
Per Unit Time
Wind Speed (9m)
Scaled Wind Speed (30 m)

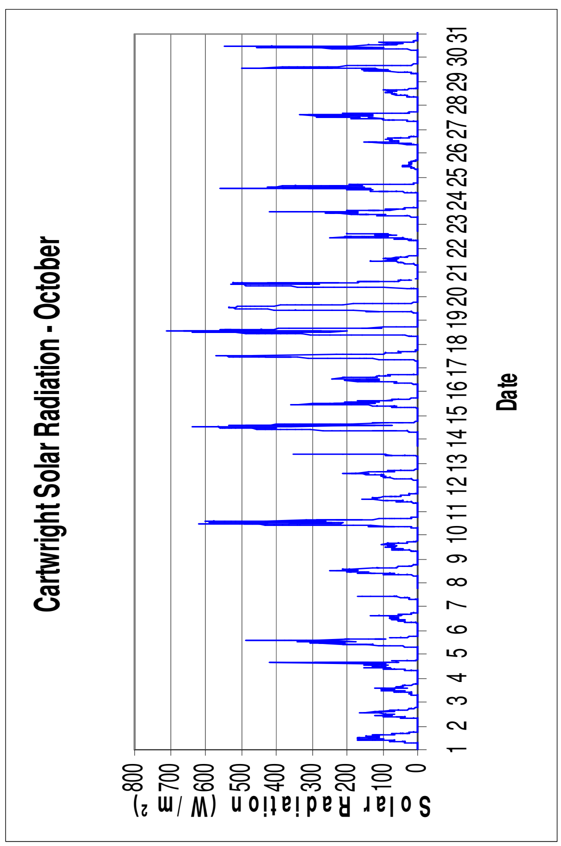

Cartwright Solar Radiation - June
Solar Radiation (W/m²)
Date

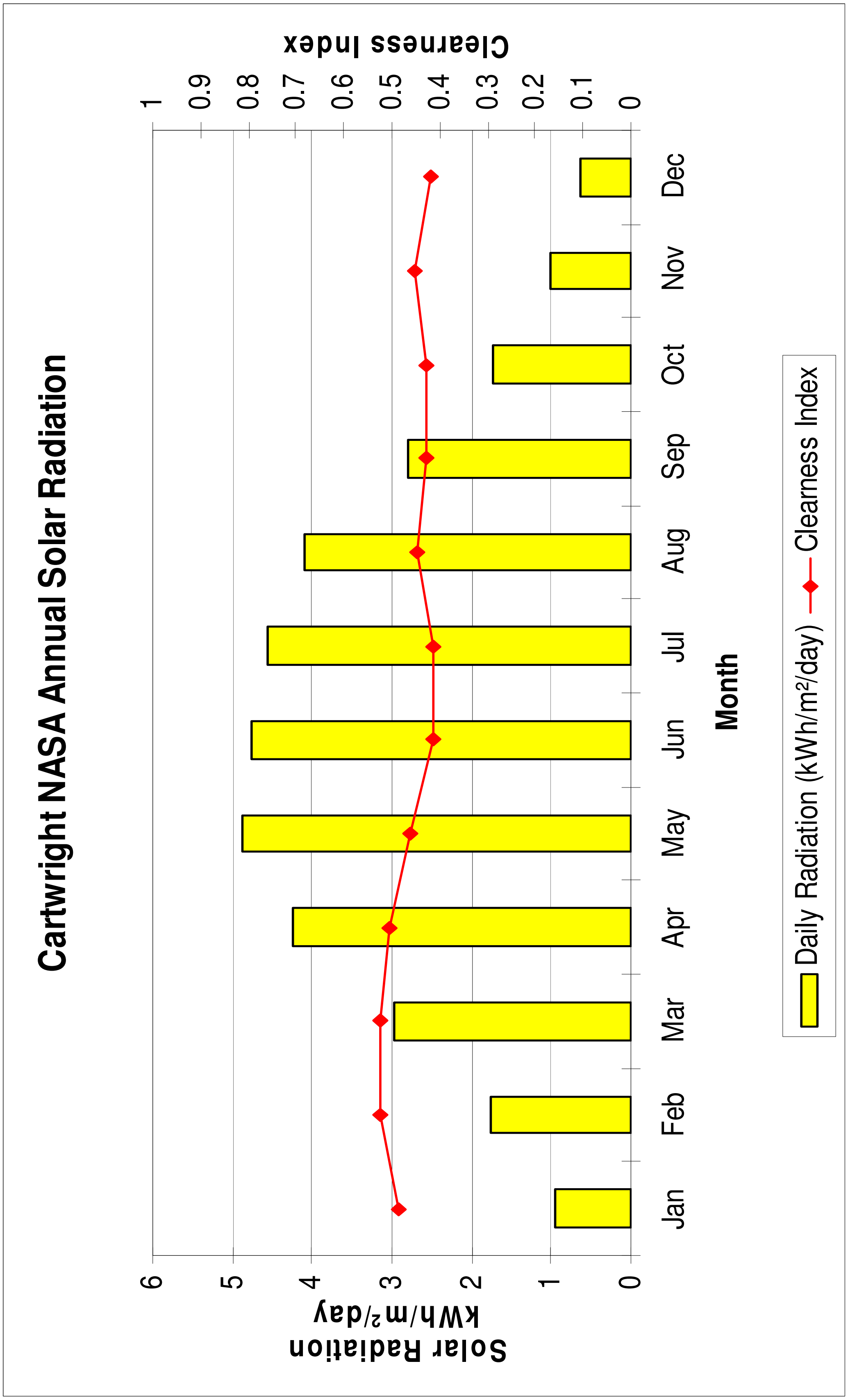

Cartwright Solar Radiation - July
Solar Radiation (W/m²)
Date

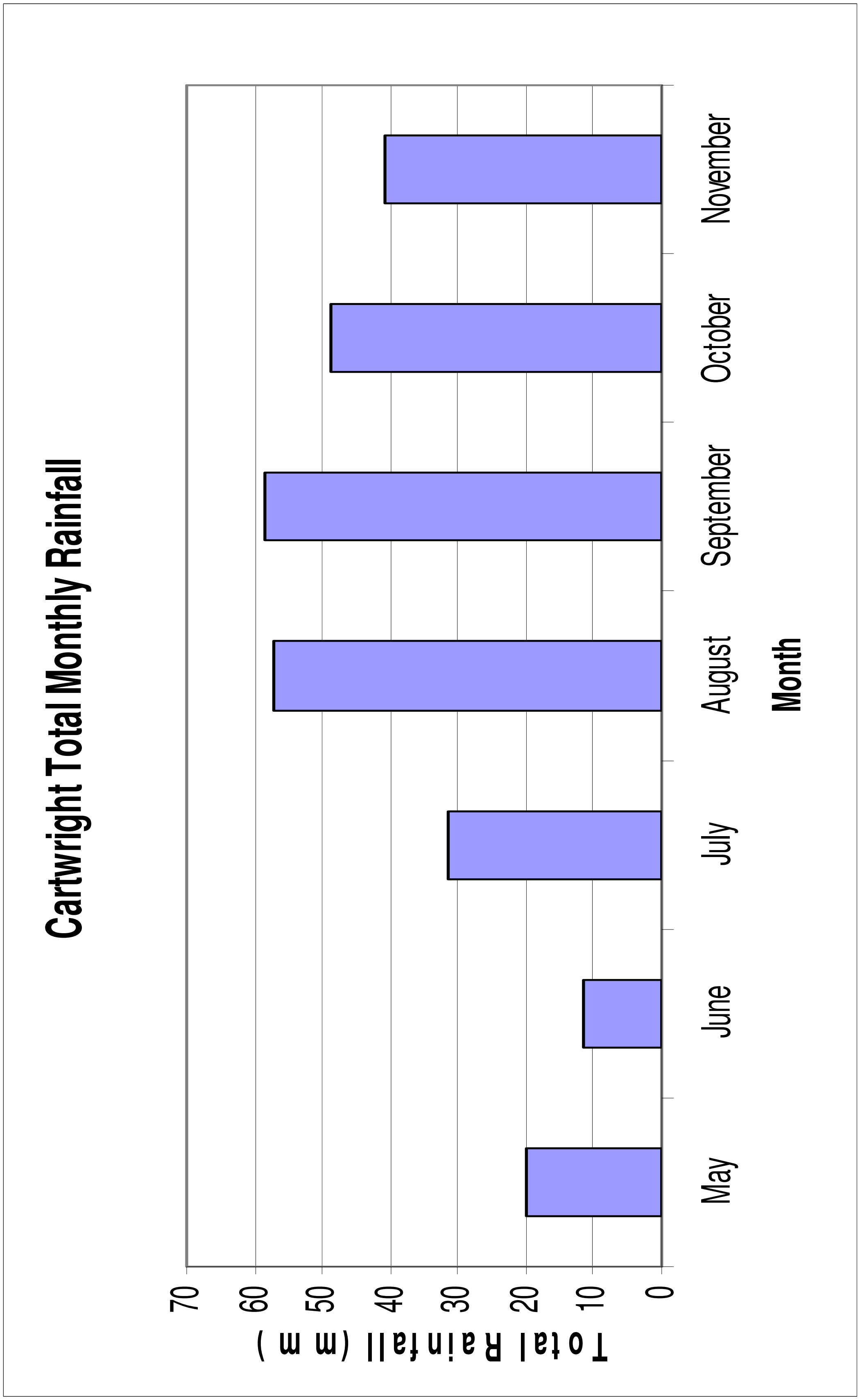

Cartwright Solar Radiation - August
Solar Radiation (W/m²)
Date


Cartwright Solar Radiation - September
Solar Radiation (W/m²)
Date


Cartwright Solar Radiation - November
Solar Radiation (W/m²)
600
500
400
300
200
100
0
1 2 3 4 5 6 7 8 9 10 11 12 13 14 15 16 17 18 19 20 21 22 23 24 25 26 27 28 29 30
Date


Cartwright Solar Radiation - October
Solar Radiation (W/m²)
800
700
600
500
400
300
200
100
0
1 2 3 4 5 6 7 8 9 10 11 12 13 14 15 16 17 18 19 20 21 22 23 24 25 26 27 28 29 30 31
Date


Cartwright NASA Annual Solar Radiation
Solar Radiation
kWh/m²/day
0
1
2
3
4
5
6
Clearness Index
0
0.1
0.2
0.3
0.4
0.5
0.6
0.7
0.8
0.9
1
Jan
Feb
Mar
Apr
May
Jun
Jul
Aug
Sep
Oct
Nov
Dec
Month
Daily Radiation (kWh/m²/day)
Clearness Index

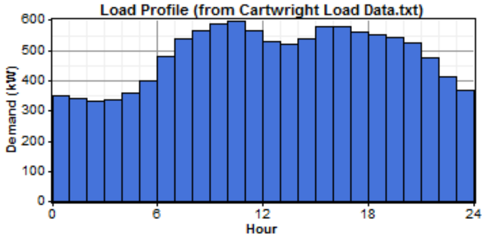

Cartwright Total Monthly Rainfall
Total Rainfall (mm)
0
10
20
30
40
50
60
70
May
June
July
August
September
October
November
Month

HOMER Input Summary

File name: Cartwright.hmr
File version: 2.67 beta
Author:

AC Load: Cartwright Net System Load

Data source:	Cartwright Load Data.txt
Daily noise:	8.89%
Hourly noise:	7.19%
Scaled annual average:	11,800, 11,995, 12,216, 12,414, 12,636 kWh/d
Scaled peak load:	978, 994, 1,013, 1,029, 1,048 kW
Load factor:	0.503



PV

Size (kW)	Capital ($)	Replacement ($)	O&M ($/yr)
50.000	400,000	400,000	10,000
100.000	750,000	750,000	15,000

Sizes to consider:	0, 50, 100 kW
Lifetime:	20 yr
Derating factor:	80%
Tracking system:	No Tracking
Slope:	53.7 deg
Azimuth:	0 deg
Ground reflectance:	20%

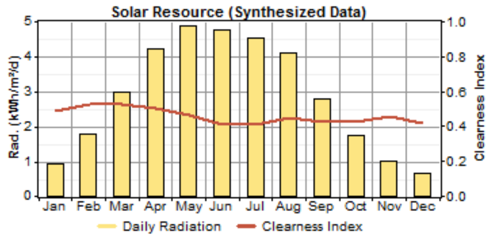
Solar Resource

Latitude: 53 degrees 42 minutes North
Longitude: 57 degrees 0 minutes West
Time zone: GMT -4:00

Data source: Synthetic

Month	Clearness Index	Average Radiation
		(kWh/m^2/day)
Jan	0.487	0.940
Feb	0.525	1.770
Mar	0.523	2.980
Apr	0.505	4.230
May	0.463	4.870
Jun	0.414	4.760
Jul	0.414	4.550
Aug	0.448	4.100
Sep	0.426	2.810
Oct	0.428	1.730
Nov	0.454	1.020
Dec	0.416	0.640

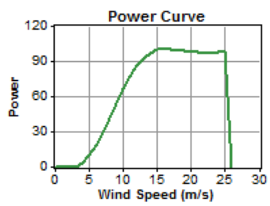
Scaled annual average: 2.86 kWh/m²/d



AC Wind Turbine: Northern Power NW100/21

Quantity	Capital ($)	Replacement ($)	O&M ($/yr)
1	500,000	400,000	10,000

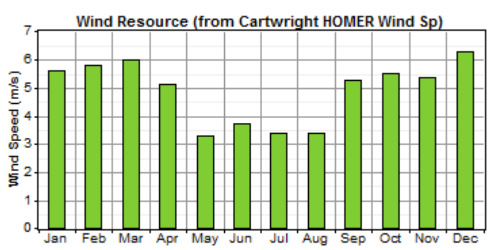
Quantities to consider:	0, 1, 2, 3, 4, 5, 6, 7, 8, 9, 10
Lifetime:	20 yr
Hub height:	37 m



Wind Resource

Data source: Cartwright HOMER Wind Speed Data.txt

Month	Wind Speed (m/s)
Jan	5.61
Feb	5.78
Mar	5.99
Apr	5.13
May	3.30
Jun	3.69
Jul	3.40
Aug	3.36
Sep	5.25
Oct	5.48
Nov	5.35
Dec	6.28



Weibull k:	1.45
Autocorrelation factor:	0.868
Diurnal pattern strength:	0.115
Hour of peak wind speed:	13
Scaled annual average:	4.88 m/s
Anemometer height:	9 m
Altitude:	9 m

Wind shear profile: Logarithmic
Surface roughness length: 0.1 m

AC Hydro:

Capital cost:	$ 20,695,000, 2,200,000
Replacement cost:	$ 0
O&M cost:	$ 263,080, 4,990/yr
Lifetime:	60 yr
Available head:	9.1, 50.0 m
Design flow rate:	26,260, 160 L/s
Min. flow ratio:	15, 10%
Max. flow ratio:	100%
Turbine efficiency:	85%
Pipe head loss:	0%

Consider systems without hydro: Yes

Hydro Resource

Data source: Synthetic

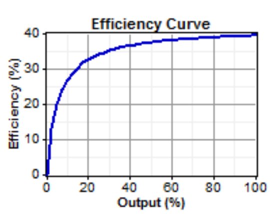
Month	Stream Flow (L/s)
Jan	765
Feb	494
Mar	482
Apr	882
May	1,765
Jun	1,706
Jul	1,765
Aug	1,765
Sep	1,706
Oct	1,765
Nov	1,706
Dec	1,294

Residual flow: 0 L/s
Scaled annual average: 1,346, 45 L/s

AC Generator: 567

Size (kW)	Capital ($)	Replacement ($)	O&M ($/hr)
600.000	0	400,000	1.684

Sizes to consider:	600 kW
Lifetime:	100,000 hrs
Min. load ratio:	30%
Heat recovery ratio:	0%
Fuel used:	#1 Diesel Arctic Grade
Fuel curve intercept:	0.0127 L/hr/kW
Fuel curve slope:	0.233 L/hr/kW

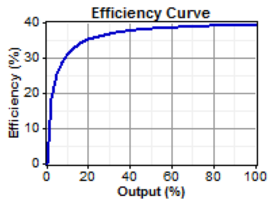


AC Generator: 2052

Size (kW)	Capital ($)	Replacement ($)	O&M ($/hr)

800.000	0	600,000	2.489

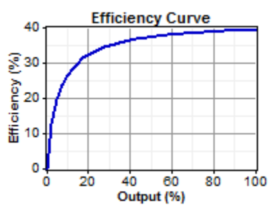
Sizes to consider: 800 kW
Lifetime: 100,000 hrs
Min. load ratio: 30%
Heat recovery ratio: 0%
Fuel used: #1 Diesel Arctic Grade
Fuel curve intercept: 0.00725 L/hr/kW
Fuel curve slope: 0.24 L/hr/kW



AC Generator: 2036

Size (kW)	Capital ($)	Replacement ($)	O&M ($/hr)
450.000	0	400,000	1.684

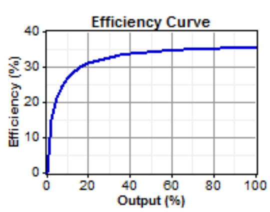
Sizes to consider: 450 kW
Lifetime: 100,000 hrs
Min. load ratio: 30%
Heat recovery ratio: 0%
Fuel used: #1 Diesel Arctic Grade
Fuel curve intercept: 0.0133 L/hr/kW
Fuel curve slope: 0.233 L/hr/kW



AC Generator: 2045

Size (kW)	Capital ($)	Replacement ($)	O&M ($/hr)
520.000	0	400,000	1.684

Sizes to consider: 520 kW
Lifetime: 100,000 hrs
Min. load ratio: 30%
Heat recovery ratio: 0%
Fuel used: #1 Diesel Arctic Grade
Fuel curve intercept: 0.00964 L/hr/kW
Fuel curve slope: 0.264 L/hr/kW



Fuel: #1 Diesel Arctic Grade

Price: $ 0.945, 0.944, 0.963, 0.993, 0.993/L
Lower heating value: 45.8 MJ/kg
Density: 809 kg/m3

Carbon content:	88.0%
Sulfur content:	0.0500%

Converter

Size (kW)	Capital ($)	Replacement ($)	O&M ($/yr)
100.000	64,000	64,000	6,400

Sizes to consider:	0, 100 kW
Lifetime:	15 yr
Inverter efficiency:	90%
Inverter can parallel with AC generator:	Yes
Rectifier relative capacity:	100%
Rectifier efficiency:	85%

Economics

Annual real interest rate:	8%
Project lifetime:	60 yr
Capacity shortage penalty:	$ 0/kWh
System fixed capital cost:	$ 0
System fixed O&M cost:	$ 0/yr

Generator control

Check load following:	Yes
Check cycle charging:	No

Allow systems with multiple generators:	Yes
Allow multiple generators to operate simultaneously:	Yes
Allow systems with generator capacity less than peak load:	No

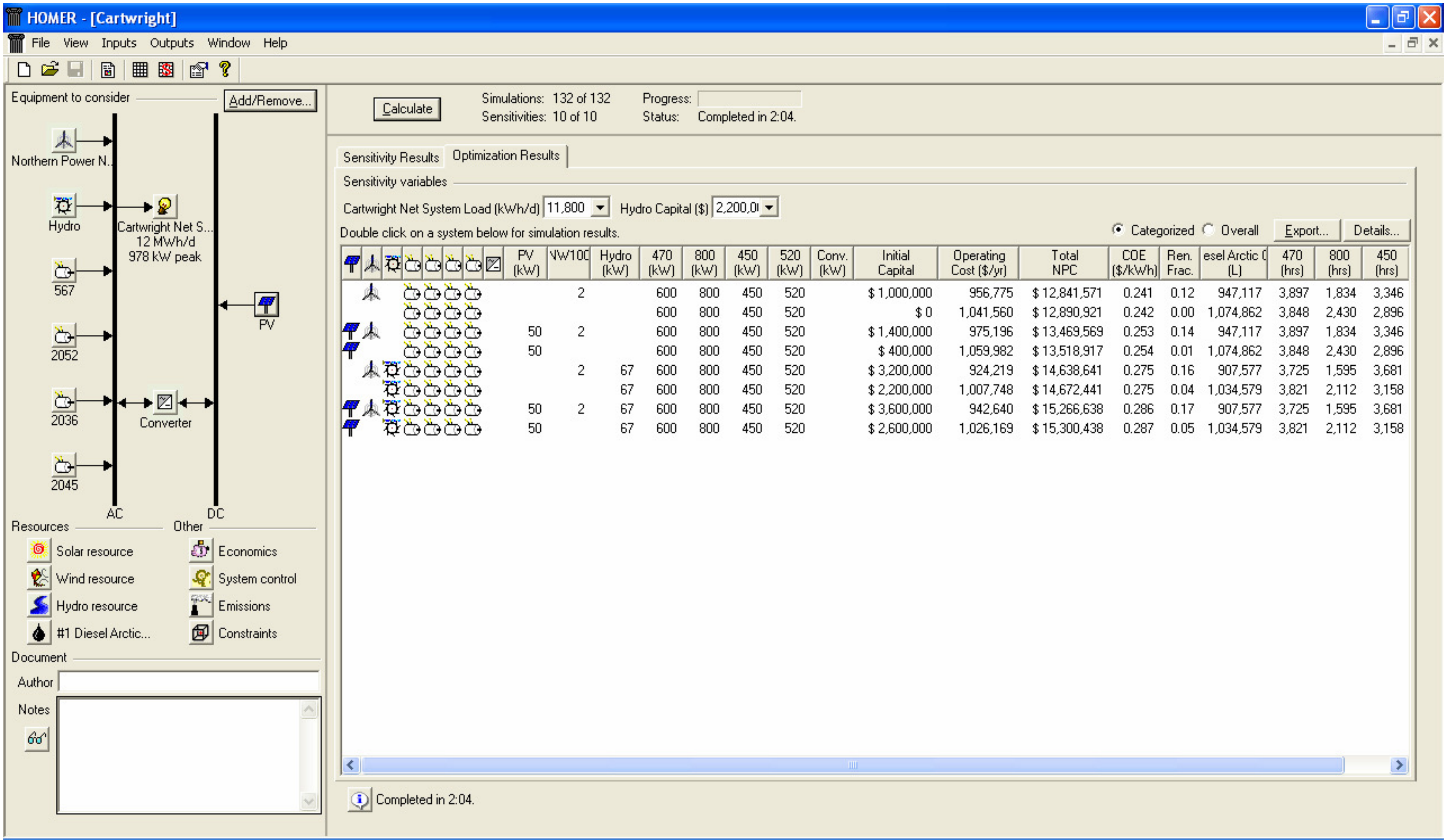
Emissions

Carbon dioxide penalty:	$ 0/t
Carbon monoxide penalty:	$ 0/t
Unburned hydrocarbons penalty:	$ 0/t
Particulate matter penalty:	$ 0/t
Sulfur dioxide penalty:	$ 0/t
Nitrogen oxides penalty:	$ 0/t

Constraints

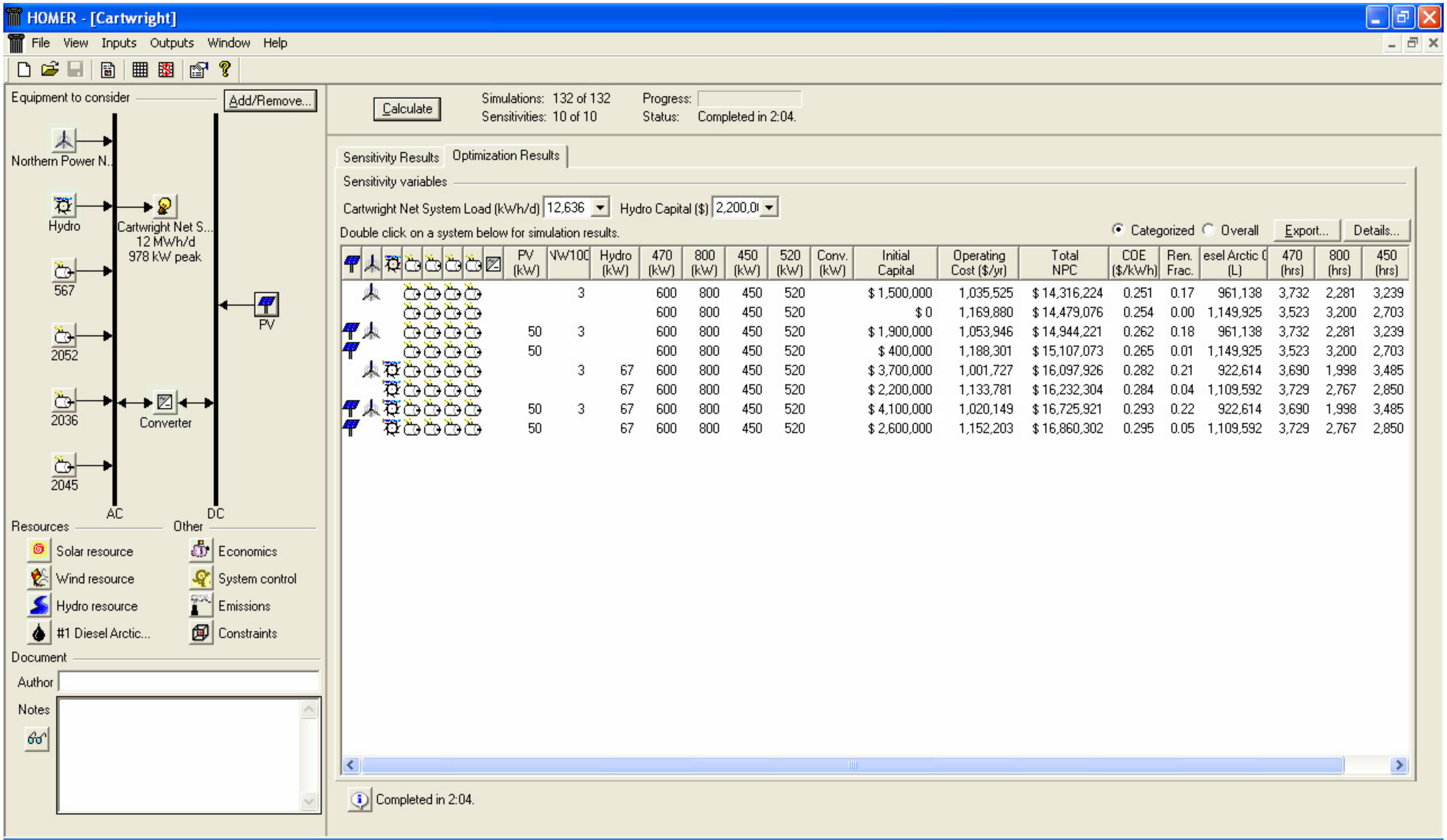
Maximum annual capacity shortage:	0%
Minimum renewable fraction:	0%

Operating reserve as percentage of hourly load:	10%
Operating reserve as percentage of peak load:	0%
Operating reserve as percentage of solar power output:	25%
Operating reserve as percentage of wind power output:	50%



PV (kW)	NW100	Hydro (kW)	470 (kW)	800 (kW)	450 (kW)	520 (kW)	Conv. (kW)	Initial Capital	Operating Cost ($/yr)	Total NPC	COE ($/kWh)	Ren. Frac.	esel Arctic (L)	470 (hrs)	800 (hrs)	450 (hrs)
	2		600	800	450	520		$ 1,000,000	956,775	$ 12,841,571	0.241	0.12	947,117	3,897	1,834	3,346
			600	800	450	520		$ 0	1,041,560	$ 12,890,921	0.242	0.00	1,074,862	3,848	2,430	2,896
50	2		600	800	450	520		$ 1,400,000	975,196	$ 13,469,569	0.253	0.14	947,117	3,897	1,834	3,346
50			600	800	450	520		$ 400,000	1,059,982	$ 13,518,917	0.254	0.01	1,074,862	3,848	2,430	2,896
	2	67	600	800	450	520		$ 3,200,000	924,219	$ 14,638,641	0.275	0.16	907,577	3,725	1,595	3,681
		67	600	800	450	520		$ 2,200,000	1,007,748	$ 14,672,441	0.275	0.04	1,034,579	3,821	2,112	3,158
50	2	67	600	800	450	520		$ 3,600,000	942,640	$ 15,266,638	0.286	0.17	907,577	3,725	1,595	3,681
50		67	600	800	450	520		$ 2,600,000	1,026,169	$ 15,300,438	0.287	0.05	1,034,579	3,821	2,112	3,158

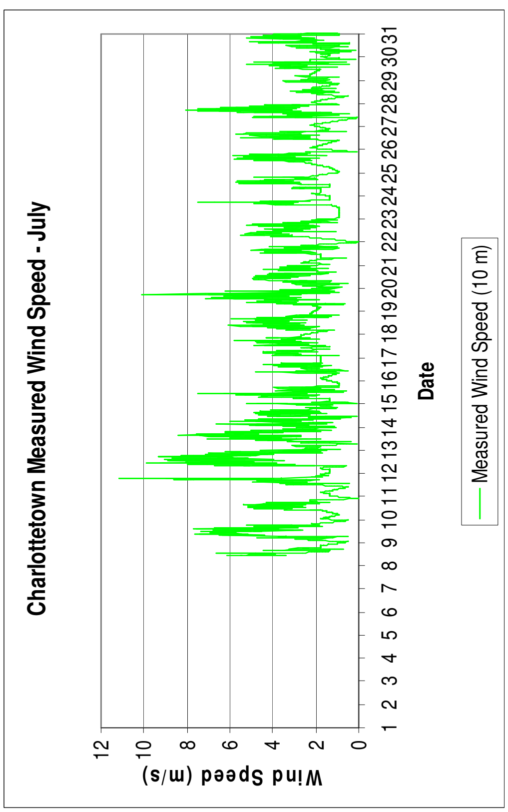
Cartwright HOMER Results – 2011 System Load

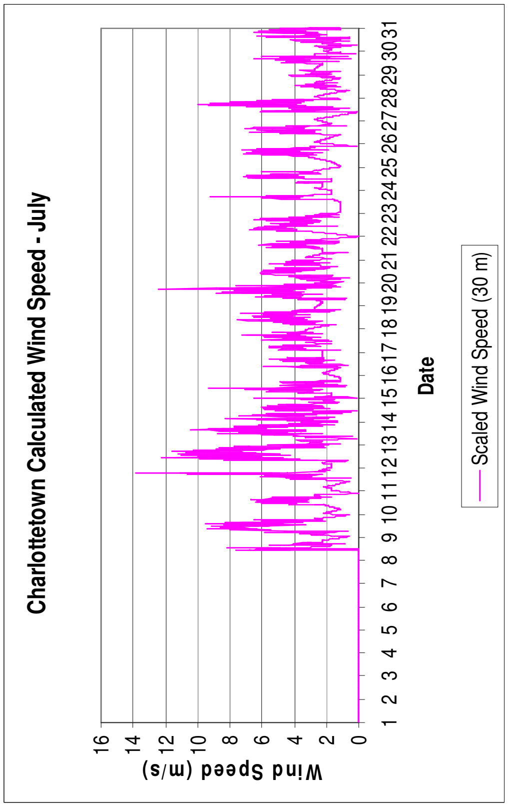


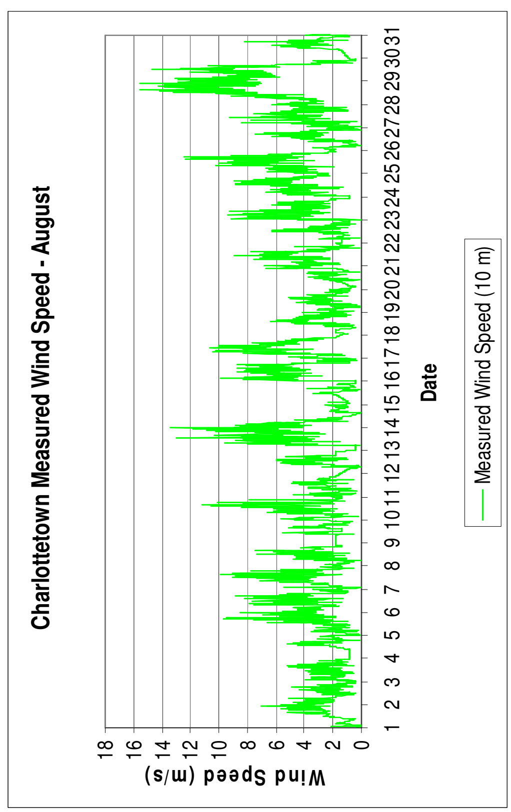
PV (kW)	NW100	Hydro (kW)	470 (kW)	800 (kW)	450 (kW)	520 (kW)	Conv. (kW)	Initial Capital	Operating Cost ($/yr)	Total NPC	COE ($/kWh)	Ren. Frac.	esel Arctic (L)	470 (hrs)	800 (hrs)	450 (hrs)
	3		600	800	450	520		$ 1,500,000	1,035,525	$ 14,316,224	0.251	0.17	961,138	3,732	2,281	3,239
			600	800	450	520		$ 0	1,169,880	$ 14,479,076	0.254	0.00	1,149,925	3,523	3,200	2,703
50	3		600	800	450	520		$ 1,900,000	1,053,946	$ 14,944,221	0.262	0.18	961,138	3,732	2,281	3,239
50			600	800	450	520		$ 400,000	1,188,301	$ 15,107,073	0.265	0.01	1,149,925	3,523	3,200	2,703
	3	67	600	800	450	520		$ 3,700,000	1,001,727	$ 16,097,926	0.282	0.21	922,614	3,690	1,998	3,485
		67	600	800	450	520		$ 2,200,000	1,133,781	$ 16,232,304	0.284	0.04	1,109,592	3,729	2,767	2,850
50	3	67	600	800	450	520		$ 4,100,000	1,020,149	$ 16,725,921	0.293	0.22	922,614	3,690	1,998	3,485
50		67	600	800	450	520		$ 2,600,000	1,152,203	$ 16,860,302	0.295	0.05	1,109,592	3,729	2,767	2,850

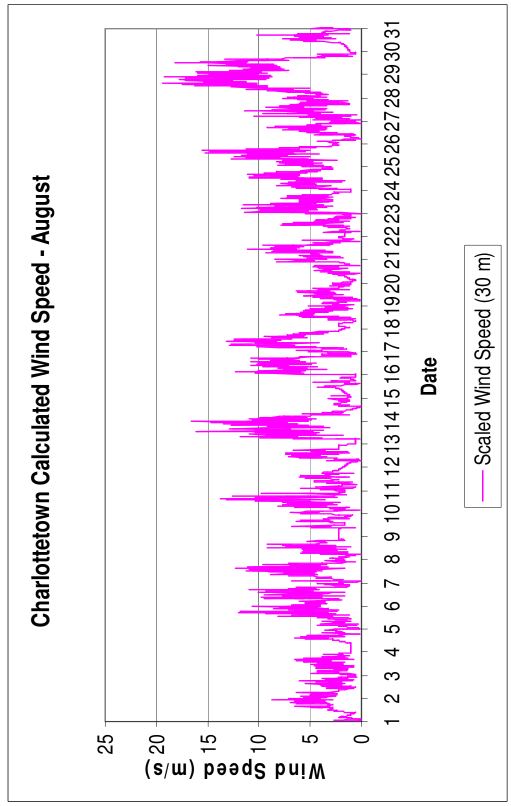
Cartwright HOMER Results – 2015 System Load

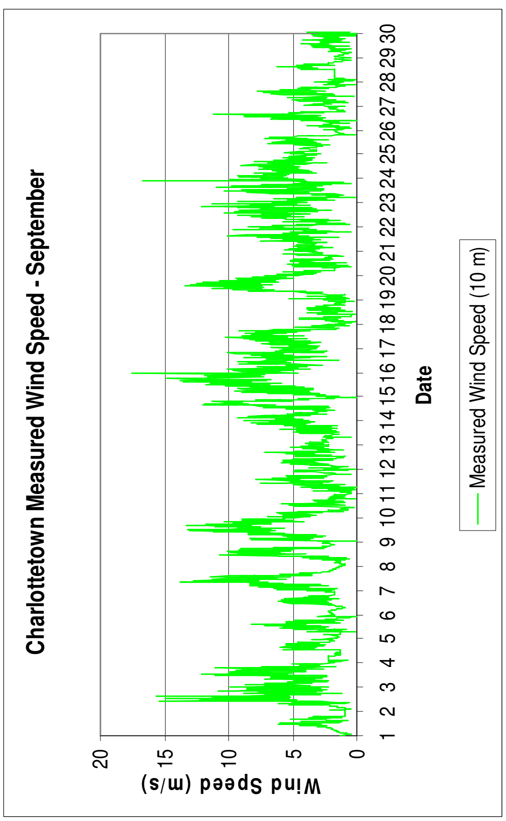
APPENDIX E - CHARLOTTETOWN

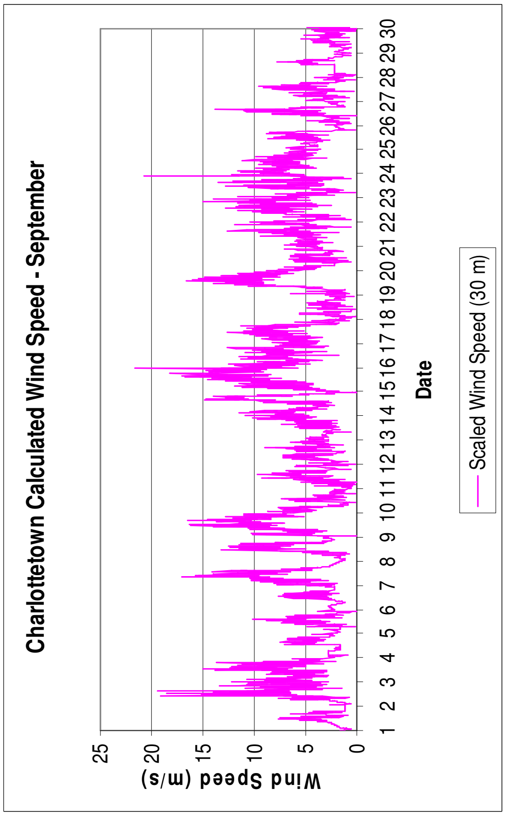

Charlottetown Measured Wind Speed - July
Wind Speed (m/s)
Date
Measured Wind Speed (10 m)

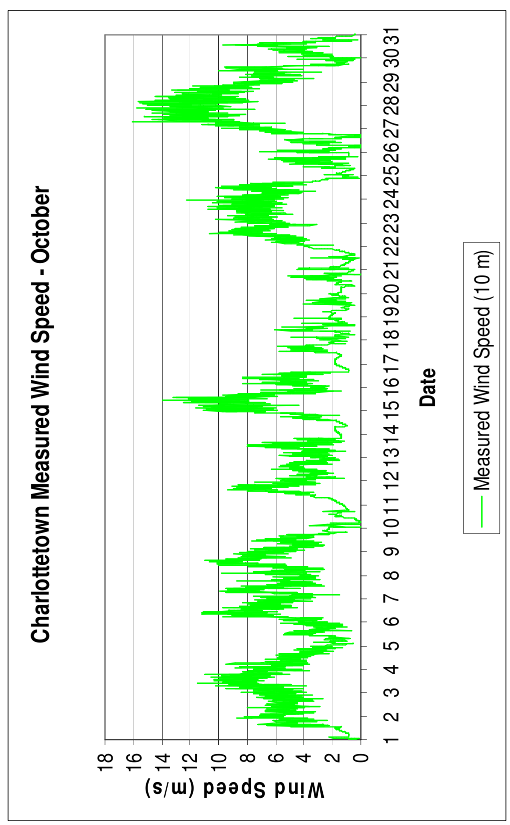

Charlottetown Calculated Wind Speed - July
Wind Speed (m/s)
Date
Scaled Wind Speed (30 m)

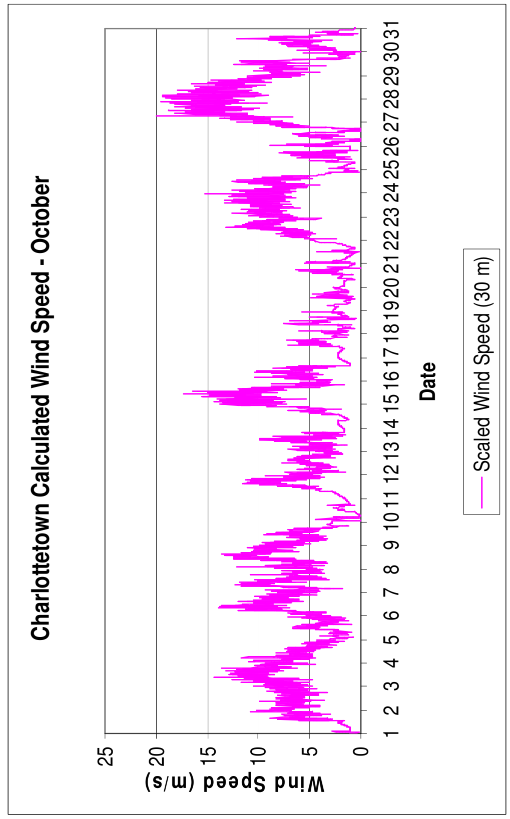

Charlottetown Measured Wind Speed - August
Wind Speed (m/s)
Date
Measured Wind Speed (10 m)

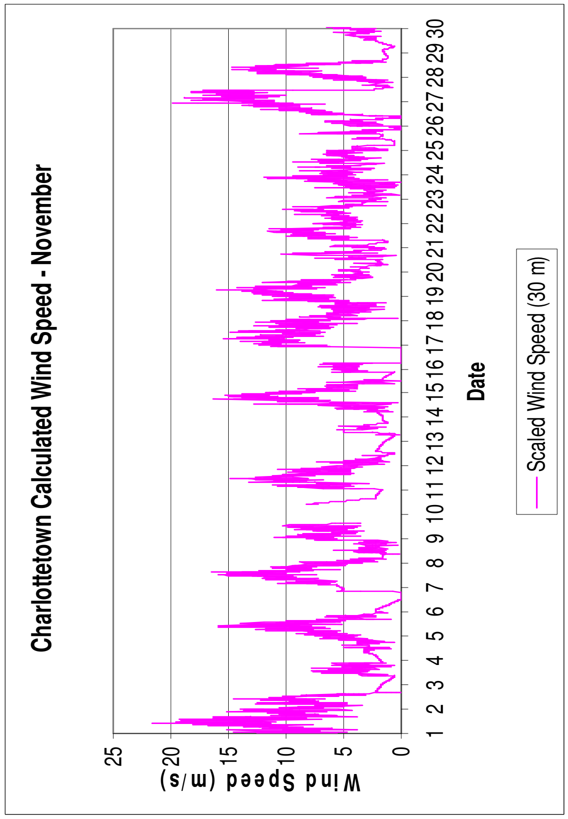

Charlottetown Calculated Wind Speed - August
Wind Speed (m/s)
Date
Scaled Wind Speed (30 m)

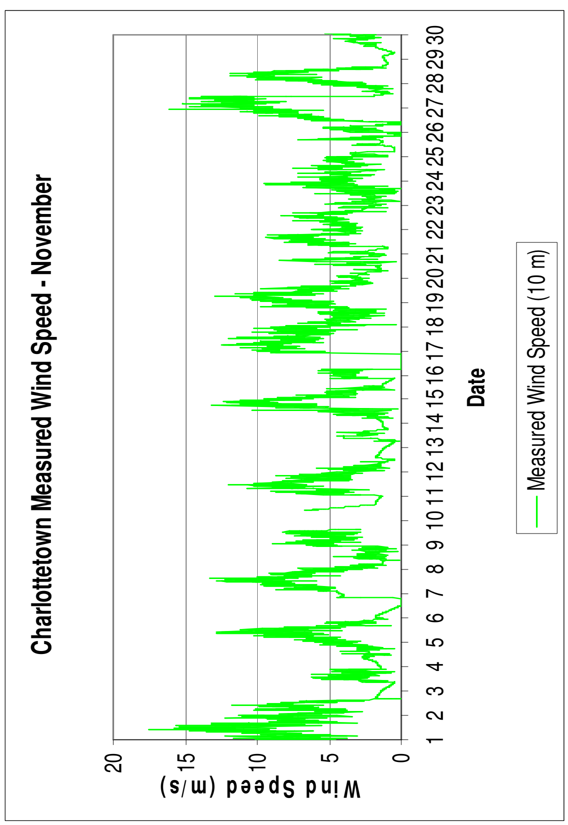

Charlottetown Measured Wind Speed - September
Wind Speed (m/s)
Date
Measured Wind Speed (10 m)

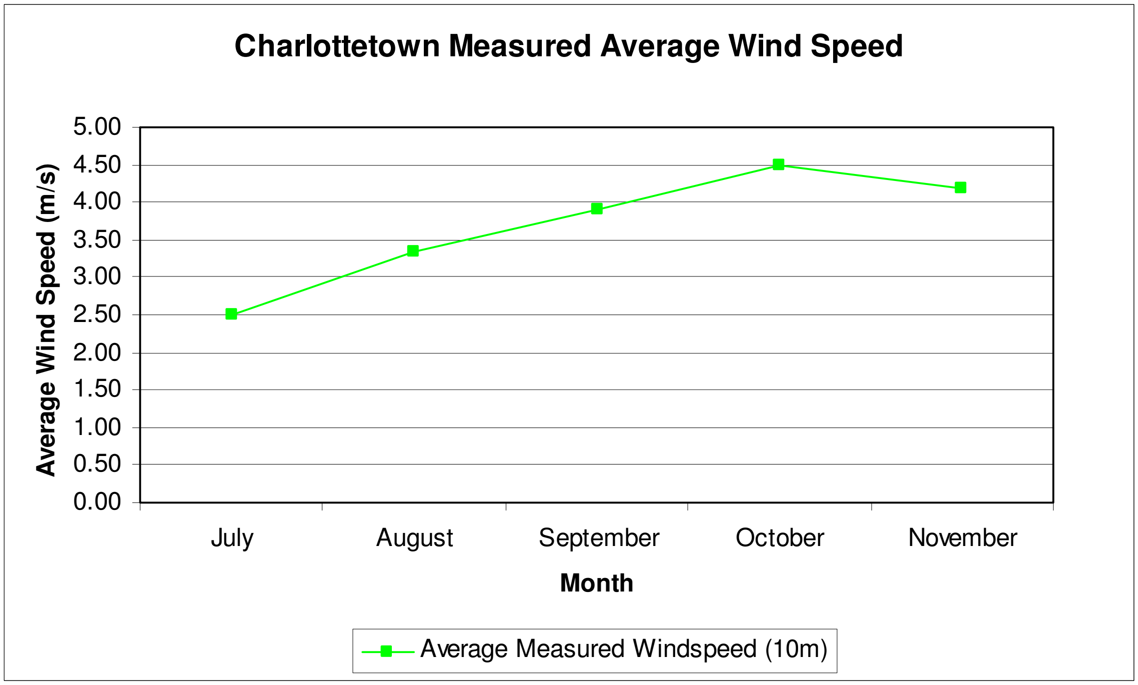

Charlottetown Calculated Wind Speed - September
Wind Speed (m/s)
Date
Scaled Wind Speed (30 m)

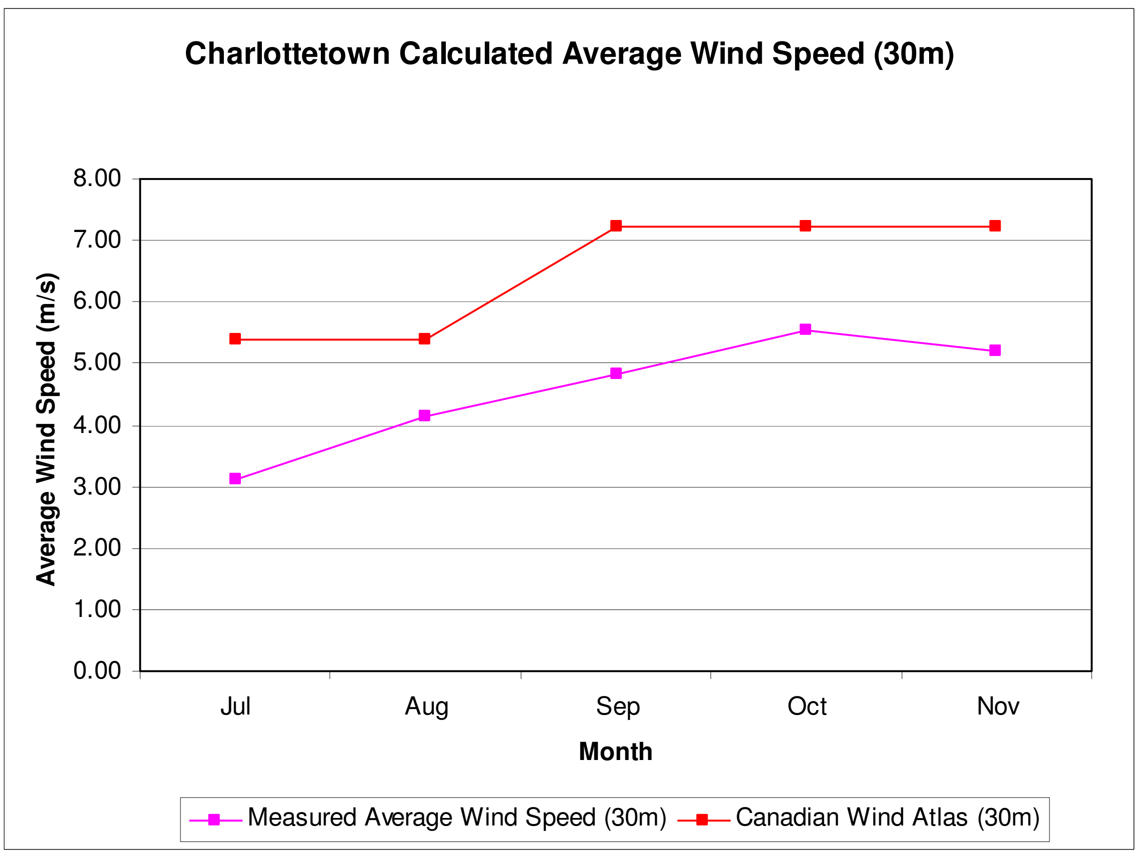

Charlottetown Measured Wind Speed - October
Wind Speed (m/s)
Date
Measured Wind Speed (10 m)

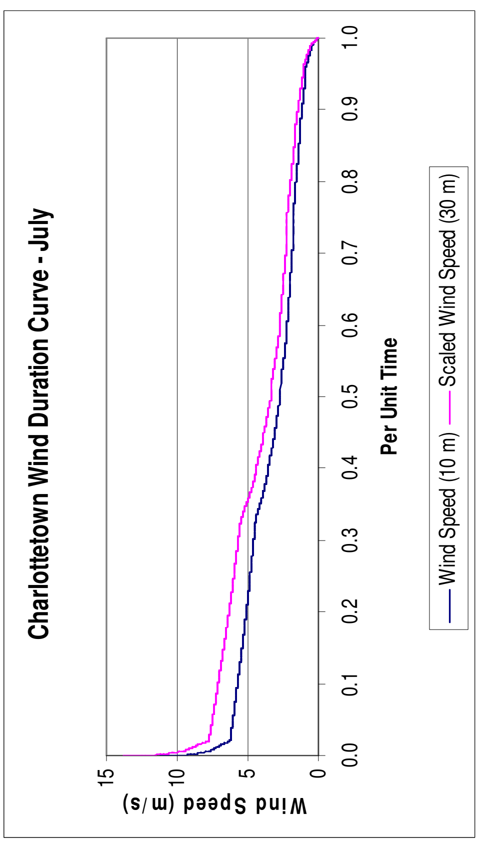

Charlottetown Calculated Wind Speed - October
Wind Speed (m/s)
Date
Scaled Wind Speed (30 m)

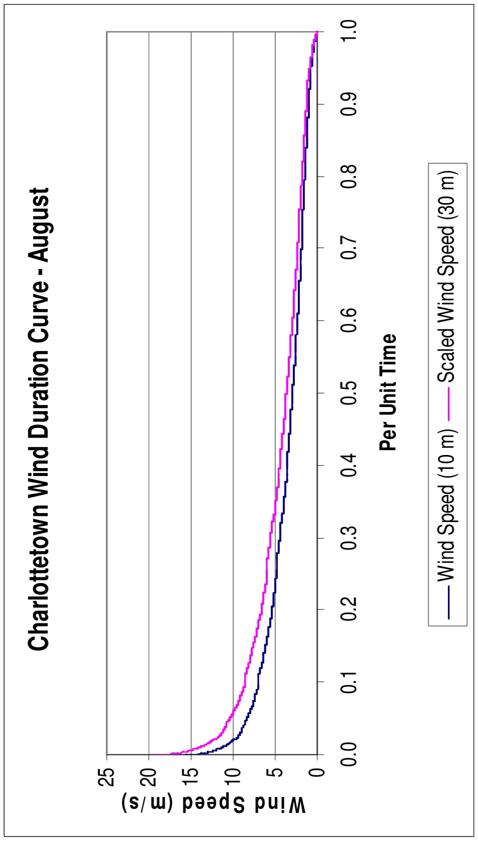

Charlottetown Calculated Wind Speed - November
Wind Speed (m/s)
0
5
10
15
20
25
1 2 3 4 5 6 7 8 9 10 11 12 13 14 15 16 17 18 19 20 21 22 23 24 25 26 27 28 29 30
Date
Scaled Wind Speed (30 m)

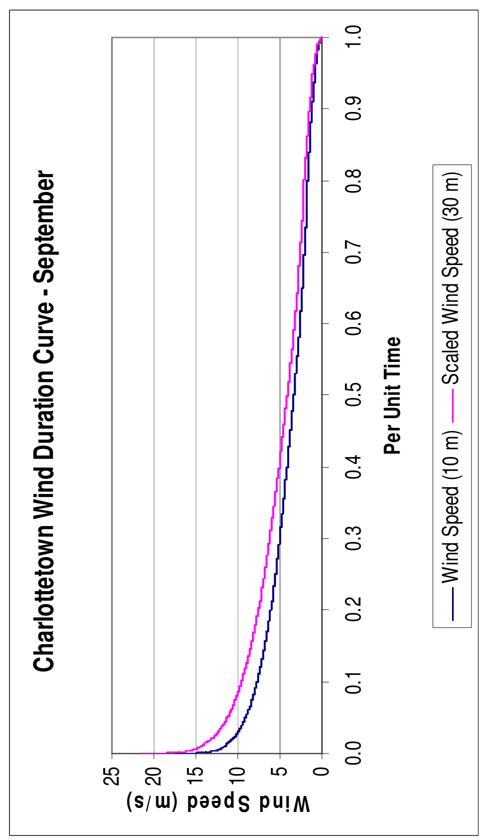

Charlottetown Measured Wind Speed - November
Wind Speed (m/s)
0
5
10
15
20
1 2 3 4 5 6 7 8 9 10 11 12 13 14 15 16 17 18 19 20 21 22 23 24 25 26 27 28 29 30
Date
Measured Wind Speed (10 m)

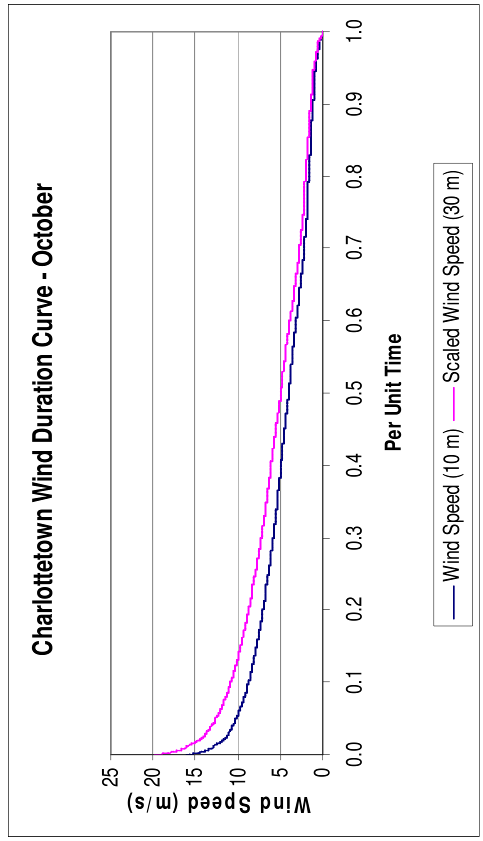

Charlottetown Measured Average Wind Speed
Average Wind Speed (m/s)
5.00
4.50
4.00
3.50
3.00
2.50
2.00
1.50
1.00
0.50
0.00
July
August
September
October
November
Month
Average Measured Windspeed (10m)

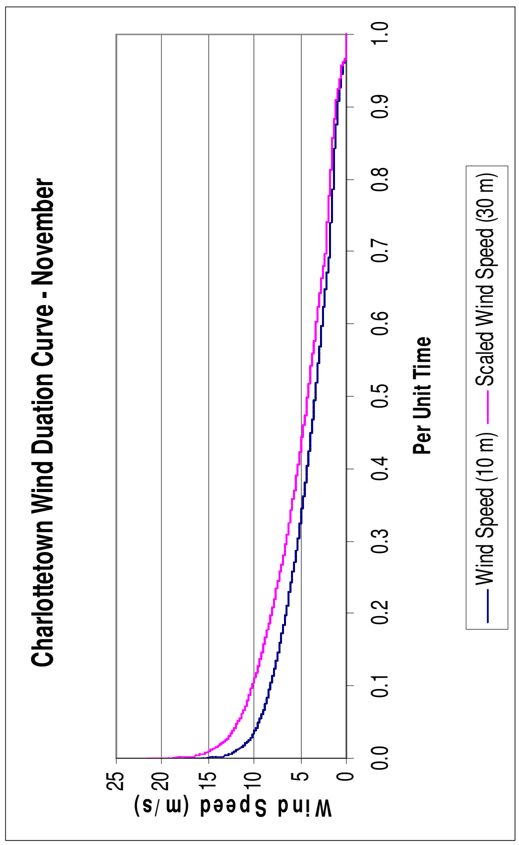

Charlottetown Calculated Average Wind Speed (30m)
Average Wind Speed (m/s)
8.00
7.00
6.00
5.00
4.00
3.00
2.00
1.00
0.00
Jul
Aug
Sep
Oct
Nov
Month
Measured Average Wind Speed (30m)
Canadian Wind Atlas (30m)

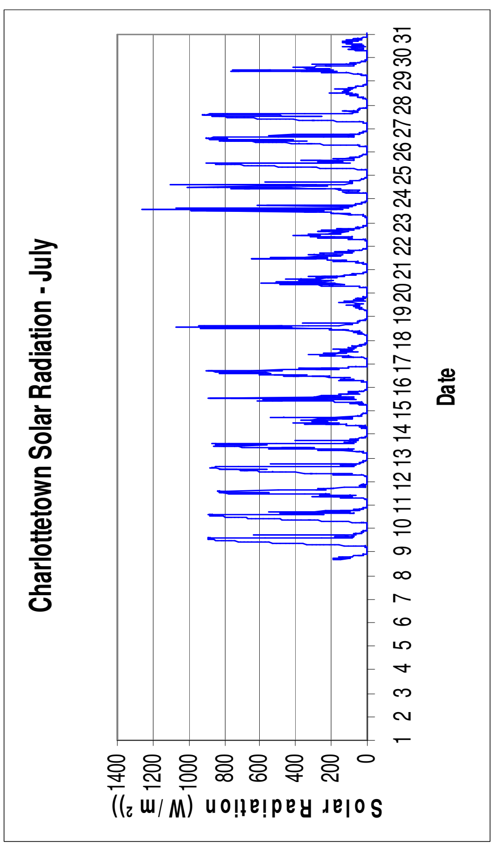

Charlottetown Wind Duration Curve - July
Wind Speed (m/s)
15
10
5
0
0.0
0.1
0.2
0.3
0.4
0.5
0.6
0.7
0.8
0.9
1.0
Per Unit Time
Wind Speed (10 m)
Scaled Wind Speed (30 m)

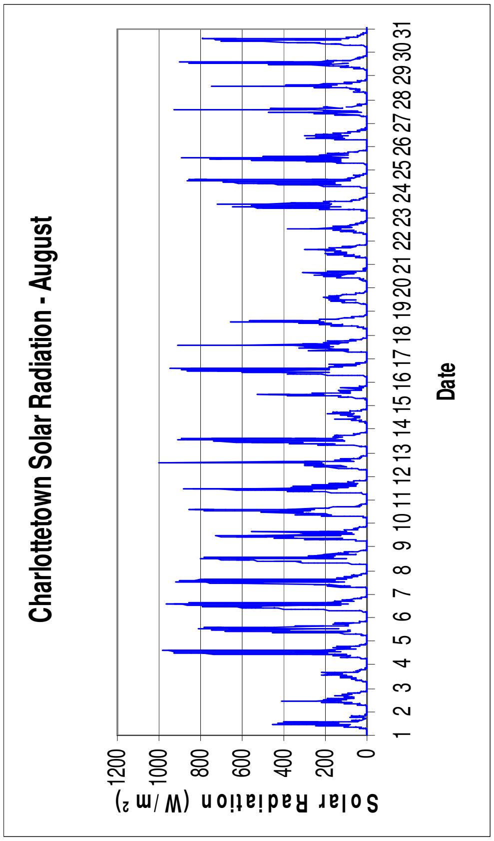

Charlottetown Wind Duration Curve - August
Wind Speed (m/s)
25
20
15
10
5
0
0.0
0.1
0.2
0.3
0.4
0.5
0.6
0.7
0.8
0.9
1.0
Per Unit Time
Wind Speed (10 m)
Scaled Wind Speed (30 m)

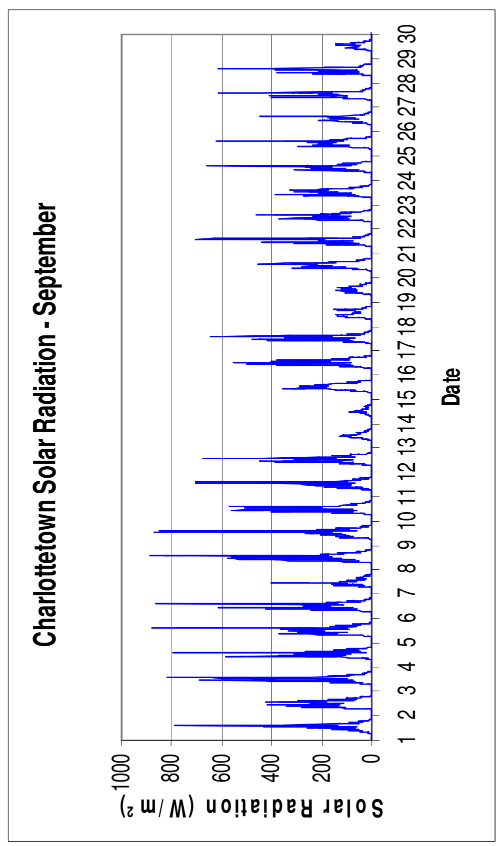

Charlottetown Wind Duration Curve - September
Wind Speed (m/s)
25
20
15
10
5
0
0.0
0.1
0.2
0.3
0.4
0.5
0.6
0.7
0.8
0.9
1.0
Per Unit Time
Wind Speed (10 m)
Scaled Wind Speed (30 m)

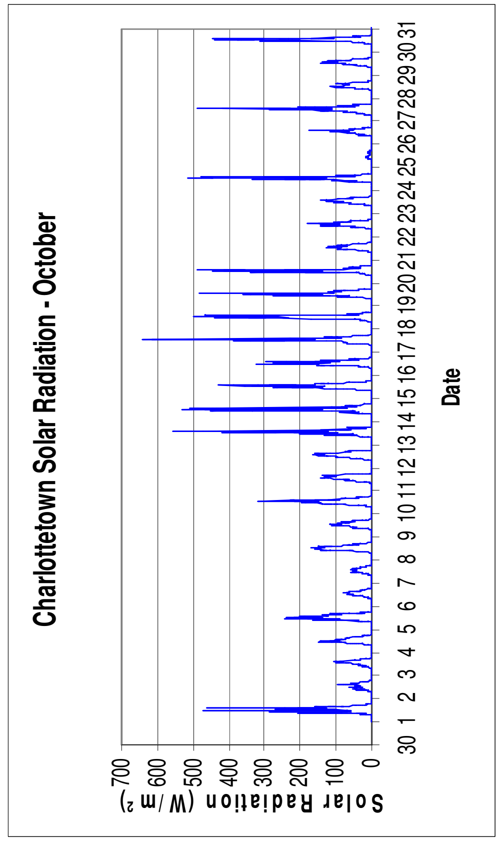

Charlottetown Wind Duration Curve - October
Wind Speed (m/s)
25
20
15
10
5
0
0.0
0.1
0.2
0.3
0.4
0.5
0.6
0.7
0.8
0.9
1.0
Per Unit Time
Wind Speed (10 m)
Scaled Wind Speed (30 m)

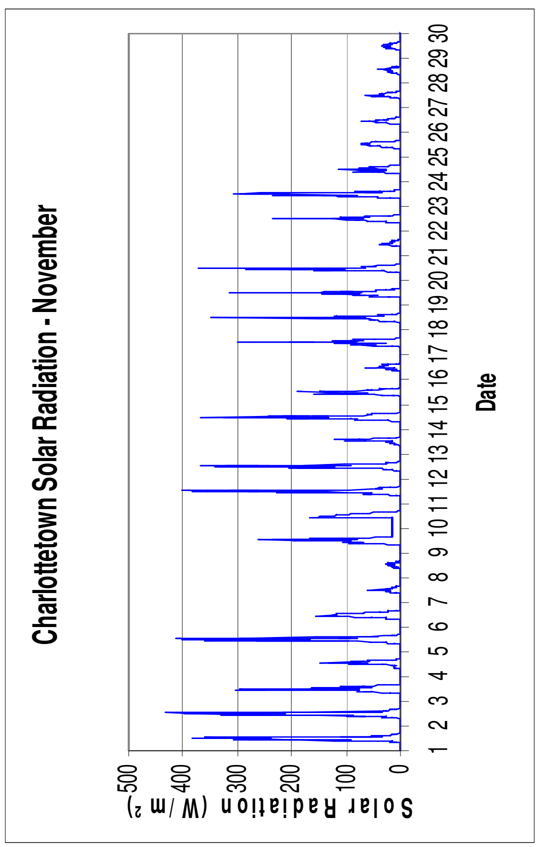

Charlottetown Wind Duation Curve - November
Wind Speed (m/s)
25
20
15
10
5
0
0.0
0.1
0.2
0.3
0.4
0.5
0.6
0.7
0.8
0.9
1.0
Per Unit Time
Wind Speed (10 m)
Scaled Wind Speed (30 m)

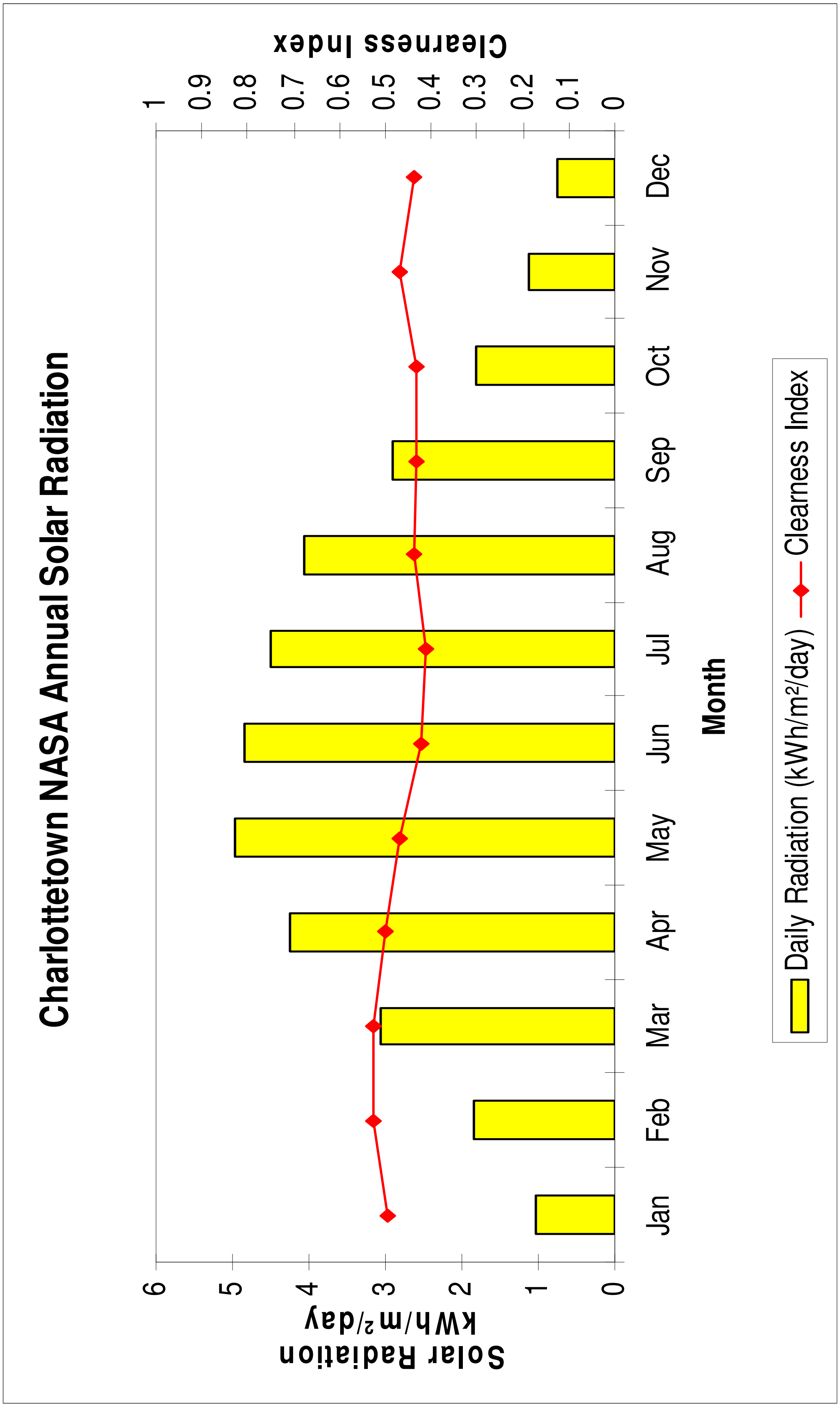

Charlottetown Solar Radiation - July
Solar Radiation (W/m²)
Date

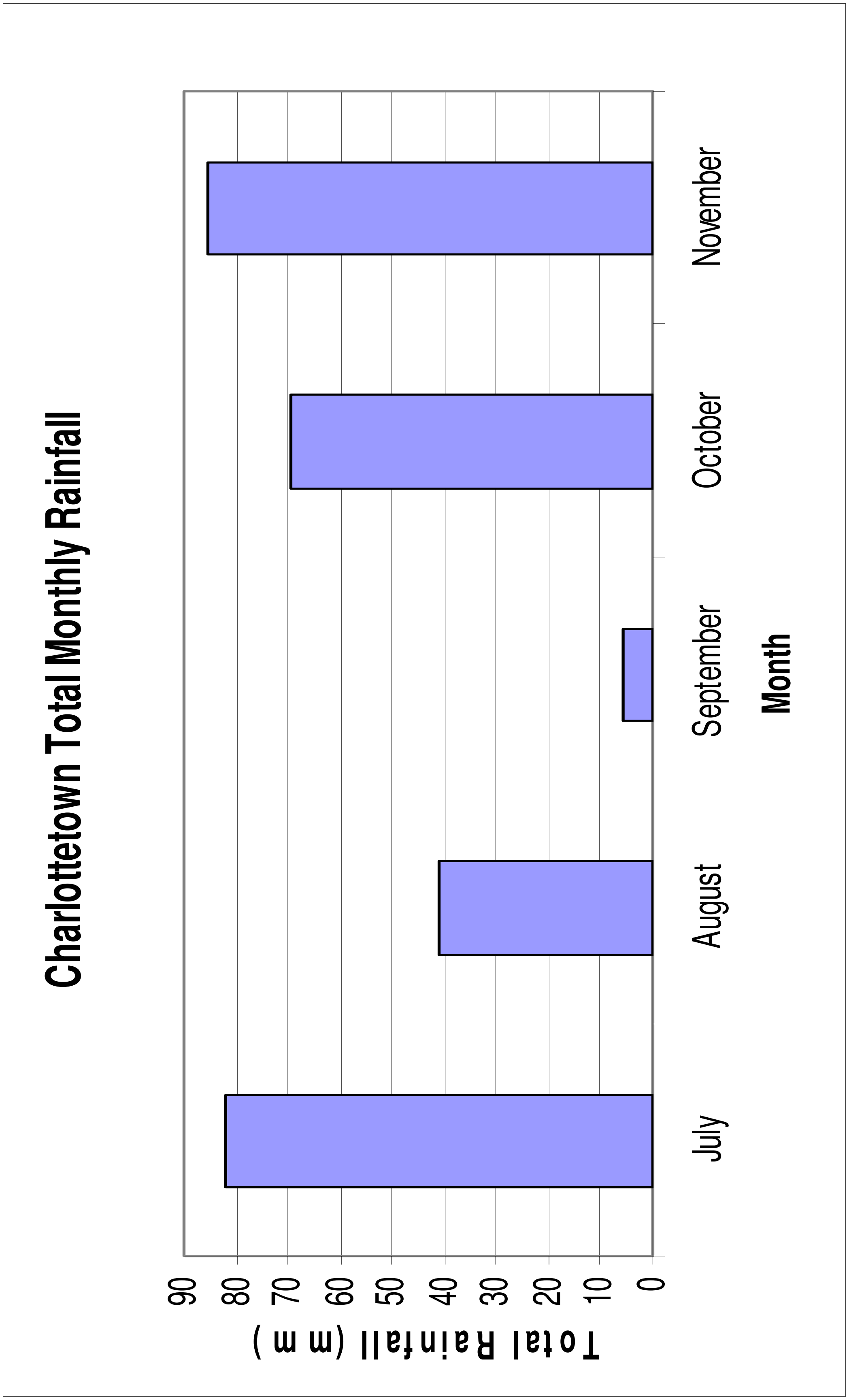

Charlottetown Solar Radiation - August
Solar Radiation (W/m²)
Date


Charlottetown Solar Radiation - September
Solar Radiation (W/m²)
Date


Charlottetown Solar Radiation - October
Solar Radiation (W/m²)
Date


Charlottetown Solar Radiation - November
Solar Radiation (W/m²)
0
100
200
300
400
500
Date
1 2 3 4 5 6 7 8 9 10 11 12 13 14 15 16 17 18 19 20 21 22 23 24 25 26 27 28 29 30


Charlottetown NASA Annual Solar Radiation
Solar Radiation
kWh/m²/day
0
1
2
3
4
5
6
Clearness Index
0
0.1
0.2
0.3
0.4
0.5
0.6
0.7
0.8
0.9
1
Jan
Feb
Mar
Apr
May
Jun
Jul
Aug
Sep
Oct
Nov
Dec
Month
Daily Radiation (kWh/m²/day)
Clearness Index

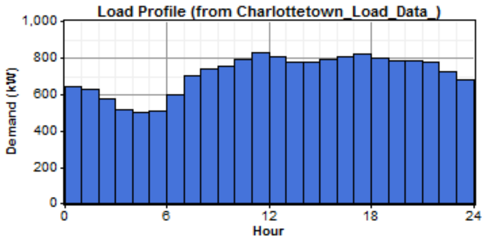

Charlottetown Total Monthly Rainfall
Total Rainfall (mm)
0
10
20
30
40
50
60
70
80
90
July
August
September
October
November
Month

HOMER Input Summary

File name: Charlottetown.hmr
File version: 2.67 beta
Author:

AC Load: Charlottetown Net System Load

Data source:	Charlottetown_Load_Data_2008.dmd
Daily noise:	8.27%
Hourly noise:	5.35%
Scaled annual average:	14,800, 14,912, 14,995, 15,104, 15,211 kWh/d
Scaled peak load:	1,185, 1,194, 1,201, 1,210, 1,218 kW
Load factor:	0.520



PV

Size (kW)	Capital ($)	Replacement ($)	O&M ($/yr)
50.000	400,000	400,000	10,000
100.000	750,000	750,000	15,000

Sizes to consider:	0, 50, 100 kW
Lifetime:	20 yr
Derating factor:	80%
Tracking system:	No Tracking
Slope:	52.8 deg
Azimuth:	0 deg
Ground reflectance:	20%

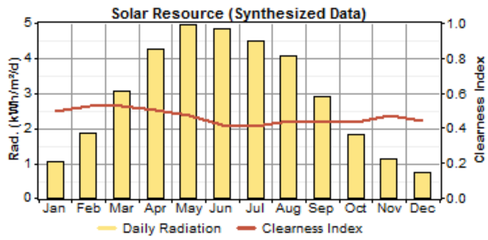
Solar Resource

Latitude: 52 degrees 46 minutes North
Longitude: 56 degrees 6 minutes West
Time zone: GMT -3:30

Data source: Synthetic

Month	Clearness Index	Average Radiation
		(kWh/m^2/day)
Jan	0.494	1.030
Feb	0.524	1.850
Mar	0.524	3.060
Apr	0.502	4.250
May	0.471	4.970
Jun	0.422	4.850
Jul	0.409	4.510
Aug	0.440	4.060
Sep	0.433	2.910
Oct	0.433	1.820
Nov	0.471	1.130
Dec	0.440	0.740

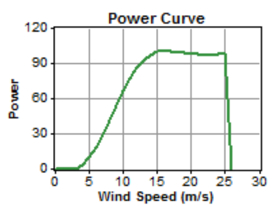
Scaled annual average: 2.92 kWh/m²/d



AC Wind Turbine: Northern Power NW100/21

Quantity	Capital ($)	Replacement ($)	O&M ($/yr)
1	500,000	400,000	10,000

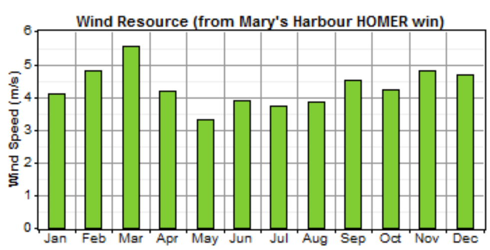
Quantities to consider:	0, 1, 2, 3, 4, 5, 6, 7, 8, 9, 10
Lifetime:	20 yr
Hub height:	37 m



Wind Resource

Data source: Mary's Harbour HOMER wind speeds.txt

Month	Wind Speed (m/s)
Jan	4.11
Feb	4.78
Mar	5.56
Apr	4.18
May	3.30
Jun	3.89
Jul	3.71
Aug	3.83
Sep	4.51
Oct	4.22
Nov	4.80
Dec	4.69



Weibull k:	1.60
Autocorrelation factor:	0.861
Diurnal pattern strength:	0.0797
Hour of peak wind speed:	10
Scaled annual average:	4.29 m/s
Anemometer height:	10 m
Altitude:	11 m

Wind shear profile: Logarithmic
Surface roughness length: 0.01 m

AC Hydro:

Capital cost:	$ 10,406,000, 40,689,000, 3,391,000, 19,175,000, 7,132,000, 4,300,000, 3,200,000
Replacement cost:	$ 0
O&M cost:	$ 193,260, 263,280, 10,900, 50,440, 15,890, 7,890, 5,450/yr
Lifetime:	60 yr
Available head:	30, 40, 20, 20, 35, 33, 32 m
Design flow rate:	5,840, 5,970, 870, 4,000, 720, 380, 270 L/s
Min. flow ratio:	15, 10, 20, 15, 15, 15, 15%
Max. flow ratio:	100%
Turbine efficiency:	85%
Pipe head loss:	0%

Consider systems without hydro: Yes

Hydro Resource

Data source: Synthetic

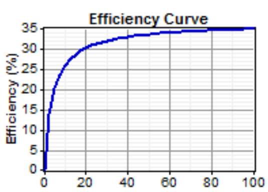
Month	Stream Flow (L/s)
Jan	824
Feb	529
Mar	588
Apr	1,671
May	1,694
Jun	1,671
Jul	1,694
Aug	1,694
Sep	1,671
Oct	1,694
Nov	1,659
Dec	1,471

Residual flow: 0 L/s
Scaled annual average: 763, 1,029, 76, 348, 109, 54, 37 L/s

AC Generator: 204

Size (kW)	Capital ($)	Replacement ($)	O&M ($/hr)
250.000	0	380,000	1.128

Sizes to consider:	250 kW
Lifetime:	100,000 hrs
Min. load ratio:	30%
Heat recovery ratio:	0%
Fuel used:	#1 Diesel Arctic Grade
Fuel curve intercept:	0.0108 L/hr/kW
Fuel curve slope:	0.268 L/hr/kW

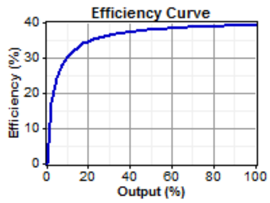


AC Generator: 2060

Size (kW)	Capital ($)	Replacement ($)	O&M ($/hr)

725.000	0	600,000	1.850

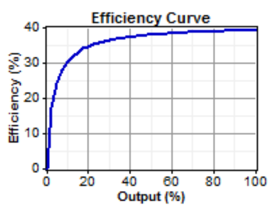
Sizes to consider: 725 kW
Lifetime: 100,000 hrs
Min. load ratio: 30%
Heat recovery ratio: 0%
Fuel used: #1 Diesel Arctic Grade
Fuel curve intercept: 0.008 L/hr/kW
Fuel curve slope: 0.24 L/hr/kW



AC Generator: 2061

Size (kW)	Capital ($)	Replacement ($)	O&M ($/hr)
725.000	0	600,000	1.850

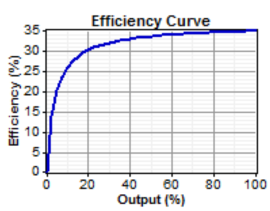
Sizes to consider: 725 kW
Lifetime: 100,000 hrs
Min. load ratio: 30%
Heat recovery ratio: 0%
Fuel used: #1 Diesel Arctic Grade
Fuel curve intercept: 0.008 L/hr/kW
Fuel curve slope: 0.24 L/hr/kW



AC Generator: 2019

Size (kW)	Capital ($)	Replacement ($)	O&M ($/hr)
250.000	0	380,000	1.128

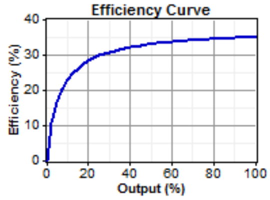
Sizes to consider: 250 kW
Lifetime: 100,000 hrs
Min. load ratio: 30%
Heat recovery ratio: 0%
Fuel used: #1 Diesel Arctic Grade
Fuel curve intercept: 0.0108 L/hr/kW
Fuel curve slope: 0.268 L/hr/kW



AC Generator: 2034

Size (kW)	Capital ($)	Replacement ($)	O&M ($/hr)
300.000	0	400,000	1.684

Sizes to consider:	300 kW
Lifetime:	100,000 hrs
Min. load ratio:	30%
Heat recovery ratio:	0%
Fuel used:	#1 Diesel Arctic Grade
Fuel curve intercept:	0.0163 L/hr/kW
Fuel curve slope:	0.261 L/hr/kW



Fuel: #1 Diesel Arctic Grade

Price:	$ 0.928, 0.927, 0.947, 0.976, 0.976/L
Lower heating value:	45.8 MJ/kg
Density:	809 kg/m3
Carbon content:	88.0%
Sulfur content:	0.0500%

Converter

Size (kW)	Capital ($)	Replacement ($)	O&M ($/yr)
100.000	64,000	64,000	6,400

Sizes to consider:	0, 100 kW
Lifetime:	15 yr
Inverter efficiency:	90%
Inverter can parallel with AC generator:	Yes
Rectifier relative capacity:	100%
Rectifier efficiency:	85%

Economics

Annual real interest rate:	8%
Project lifetime:	60 yr
Capacity shortage penalty:	$ 0/kWh
System fixed capital cost:	$ 0
System fixed O&M cost:	$ 0/yr

Generator control

Check load following:	Yes
Check cycle charging:	No

Allow systems with multiple generators:	Yes
Allow multiple generators to operate simultaneously:	Yes
Allow systems with generator capacity less than peak load:	No

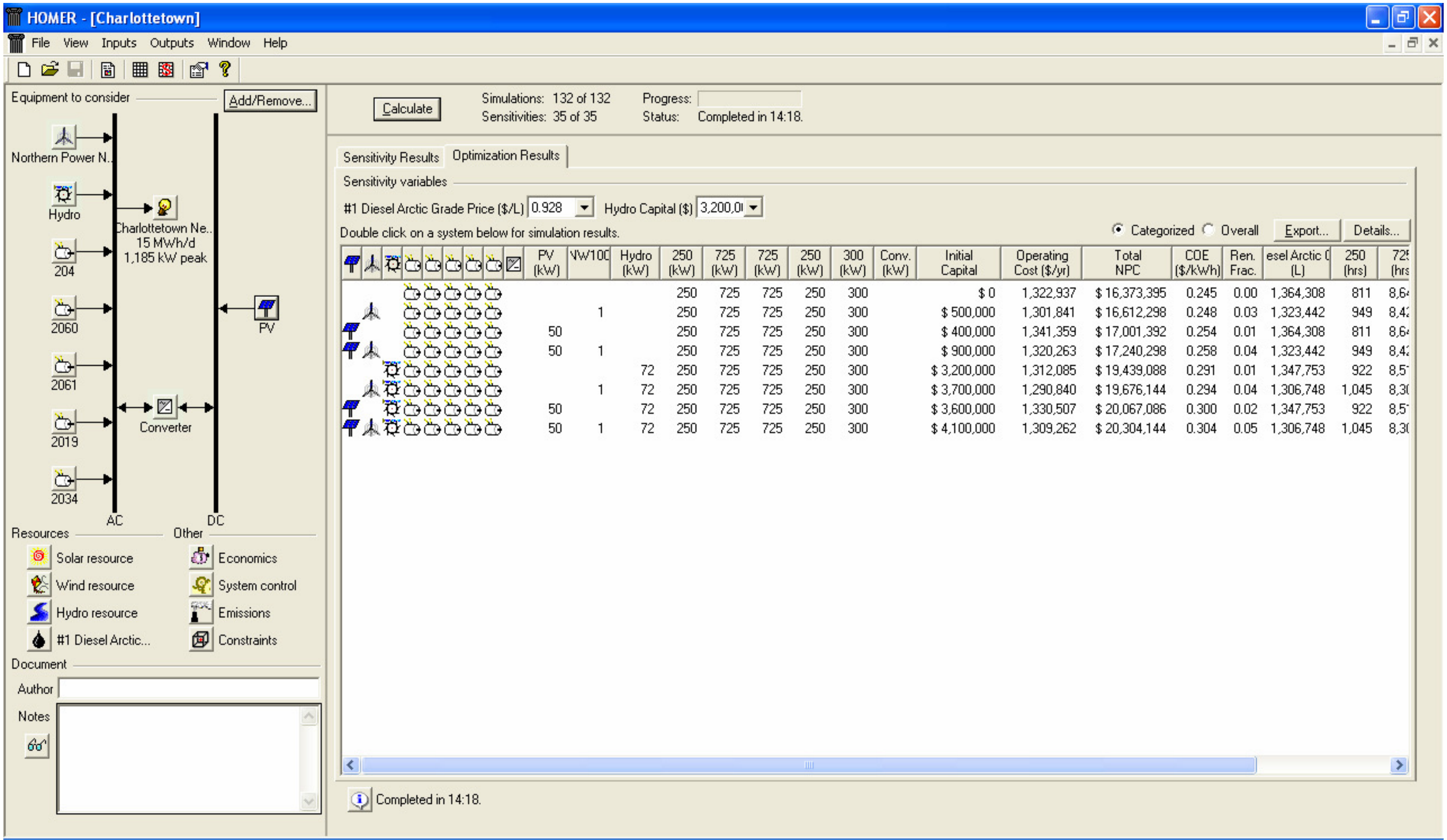
Emissions

Carbon dioxide penalty:	$ 0/t
Carbon monoxide penalty:	$ 0/t
Unburned hydrocarbons penalty:	$ 0/t
Particulate matter penalty:	$ 0/t
Sulfur dioxide penalty:	$ 0/t
Nitrogen oxides penalty:	$ 0/t

Constraints

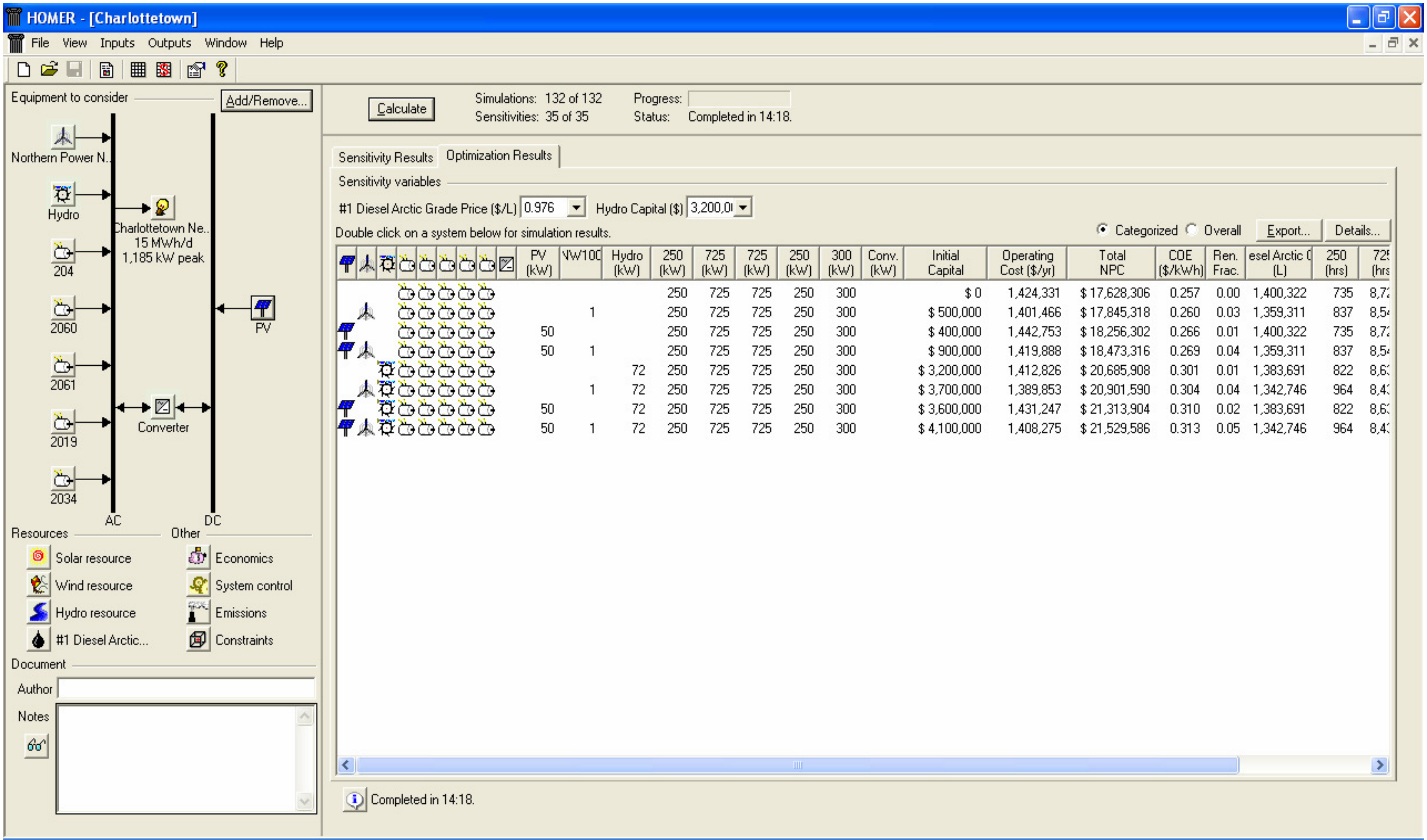
Maximum annual capacity shortage:	0%
Minimum renewable fraction:	0%

Operating reserve as percentage of hourly load:	10%
Operating reserve as percentage of peak load:	0%
Operating reserve as percentage of solar power output:	25%
Operating reserve as percentage of wind power output:	50%



PV (kW)	NW100	Hydro (kW)	250 (kW)	725 (kW)	725 (kW)	250 (kW)	300 (kW)	Conv. (kW)	Initial Capital	Operating Cost ($/yr)	Total NPC	COE ($/kWh)	Ren. Frac.	esel Arctic ((L)	250 (hrs)	725 (hrs
			250	725	725	250	300		$ 0	1,322,937	$ 16,373,395	0.245	0.00	1,364,308	811	8,6
	1		250	725	725	250	300		$ 500,000	1,301,841	$ 16,612,298	0.248	0.03	1,323,442	949	8,4
50			250	725	725	250	300		$ 400,000	1,341,359	$ 17,001,392	0.254	0.01	1,364,308	811	8,6
50	1		250	725	725	250	300		$ 900,000	1,320,263	$ 17,240,298	0.258	0.04	1,323,442	949	8,4
		72	250	725	725	250	300		$ 3,200,000	1,312,085	$ 19,439,088	0.291	0.01	1,347,753	922	8,5
	1	72	250	725	725	250	300		$ 3,700,000	1,290,840	$ 19,676,144	0.294	0.04	1,306,748	1,045	8,3
50		72	250	725	725	250	300		$ 3,600,000	1,330,507	$ 20,067,086	0.300	0.02	1,347,753	922	8,5
50	1	72	250	725	725	250	300		$ 4,100,000	1,309,262	$ 20,304,144	0.304	0.05	1,306,748	1,045	8,3

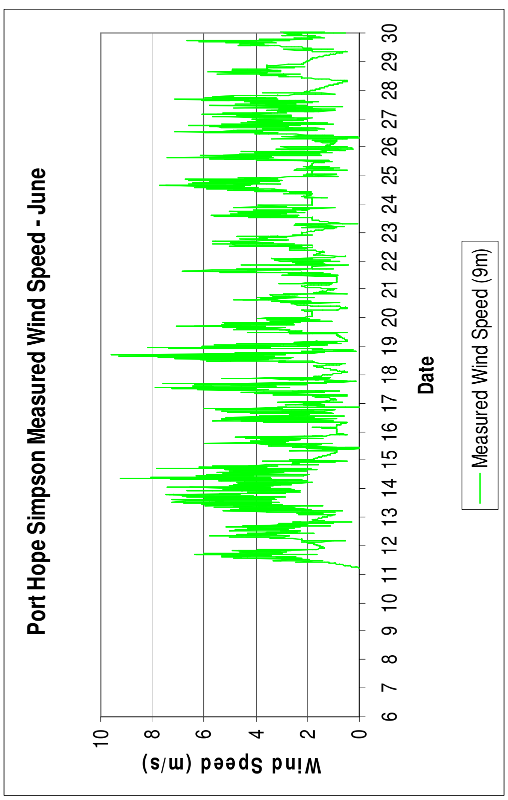
Charlottetown HOMER Results – 2011 System

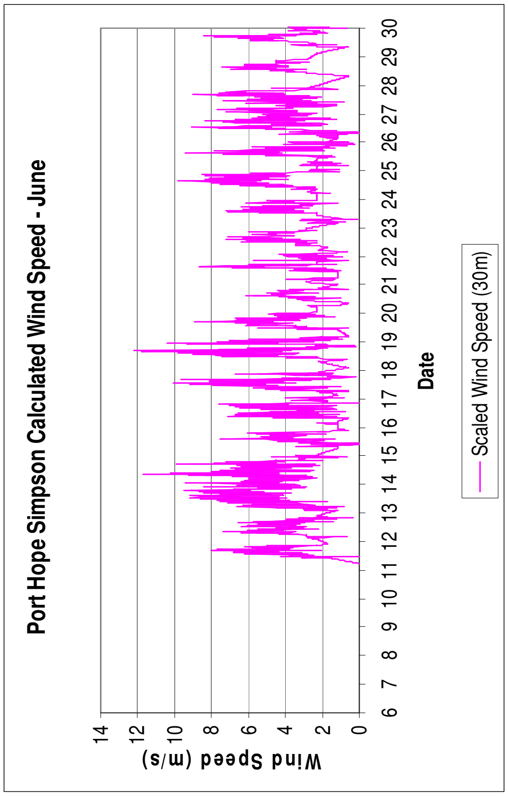


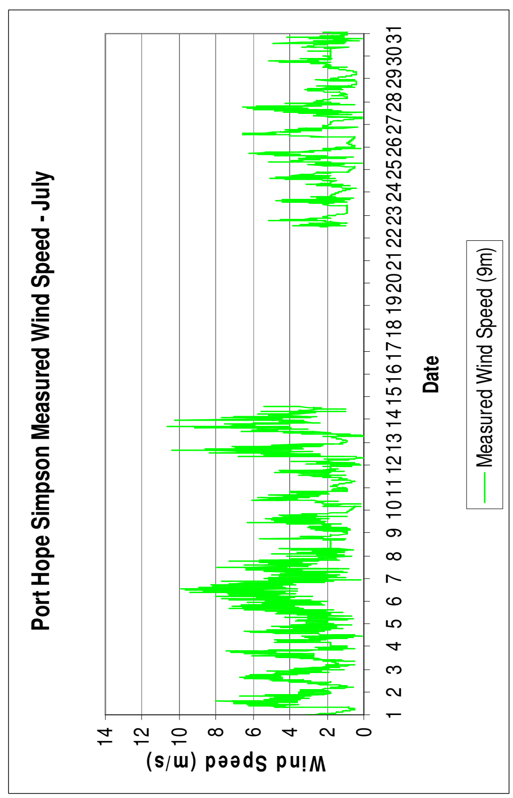
PV (kW)	W100	Hydro (kW)	250 (kW)	725 (kW)	725 (kW)	250 (kW)	300 (kW)	Conv. (kW)	Initial Capital	Operating Cost ($/yr)	Total NPC	COE ($/kWh)	Ren. Frac.	esel Arctic ((L)	250 (hrs)	72 (hrs
			250	725	725	250	300		$ 0	1,424,331	$ 17,628,306	0.257	0.00	1,400,322	735	8,7
	1		250	725	725	250	300		$ 500,000	1,401,466	$ 17,845,318	0.260	0.03	1,359,311	837	8,5
50			250	725	725	250	300		$ 400,000	1,442,753	$ 18,256,302	0.266	0.01	1,400,322	735	8,7
50	1		250	725	725	250	300		$ 900,000	1,419,888	$ 18,473,316	0.269	0.04	1,359,311	837	8,5
		72	250	725	725	250	300		$ 3,200,000	1,412,826	$ 20,685,908	0.301	0.01	1,383,691	822	8,6
	1	72	250	725	725	250	300		$ 3,700,000	1,389,853	$ 20,901,590	0.304	0.04	1,342,746	964	8,4
50		72	250	725	725	250	300		$ 3,600,000	1,431,247	$ 21,313,904	0.310	0.02	1,383,691	822	8,6
50	1	72	250	725	725	250	300		$ 4,100,000	1,408,275	$ 21,529,586	0.313	0.05	1,342,746	964	8,4

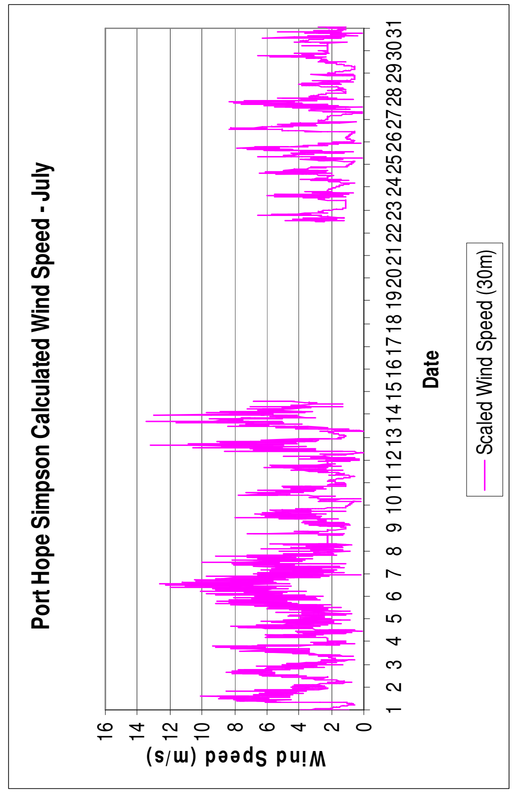
Charlottetown HOMER Results – 2015 System

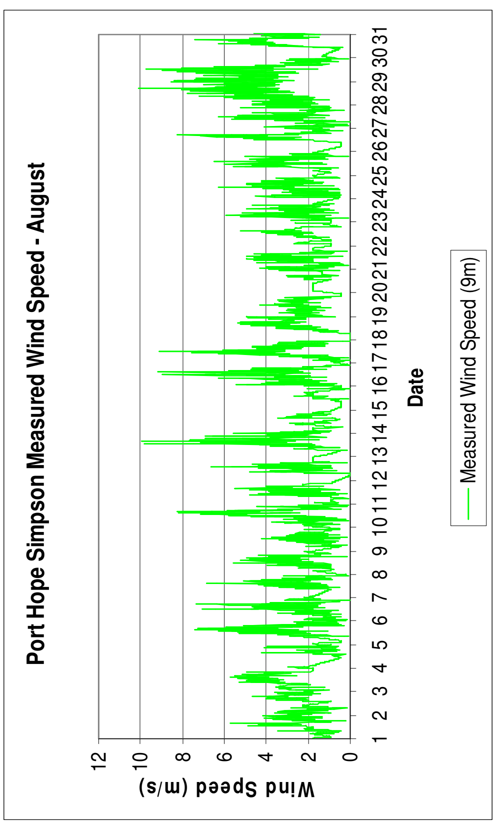
APPENDIX F – PORT HOPE SIMPSON

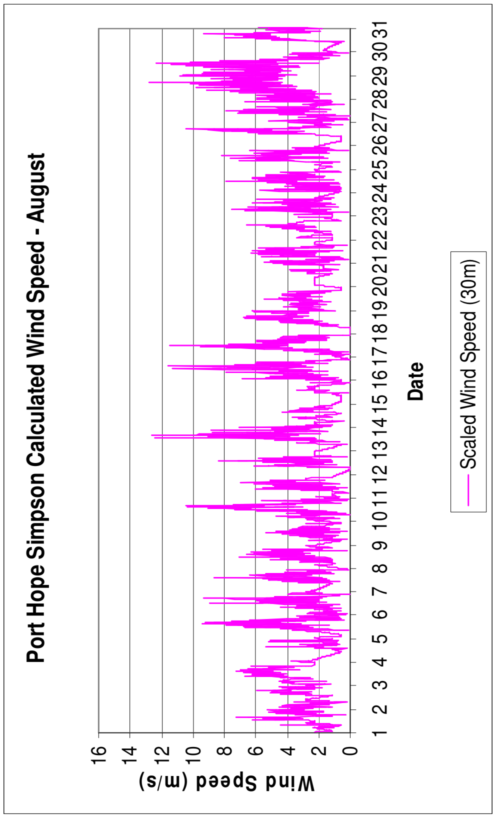

Port Hope Simpson Measured Wind Speed - June
Wind Speed (m/s)
Date
Measured Wind Speed (9m)

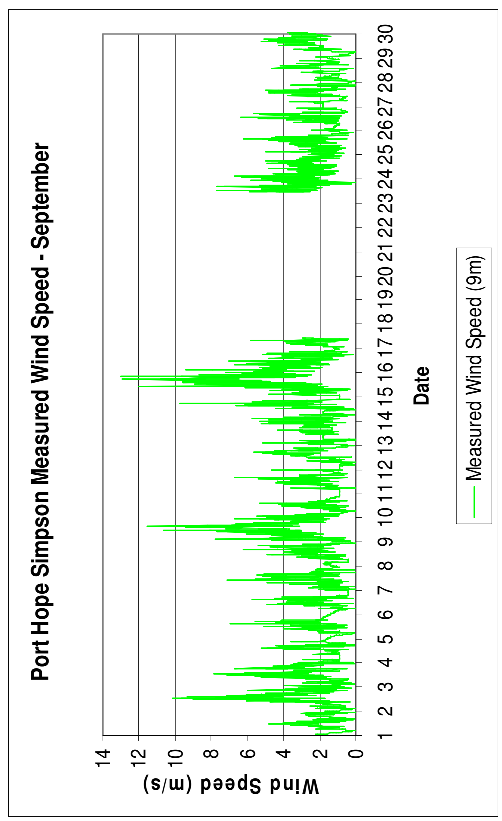

Port Hope Simpson Calculated Wind Speed - June
Wind Speed (m/s)
Date
Scaled Wind Speed (30m)

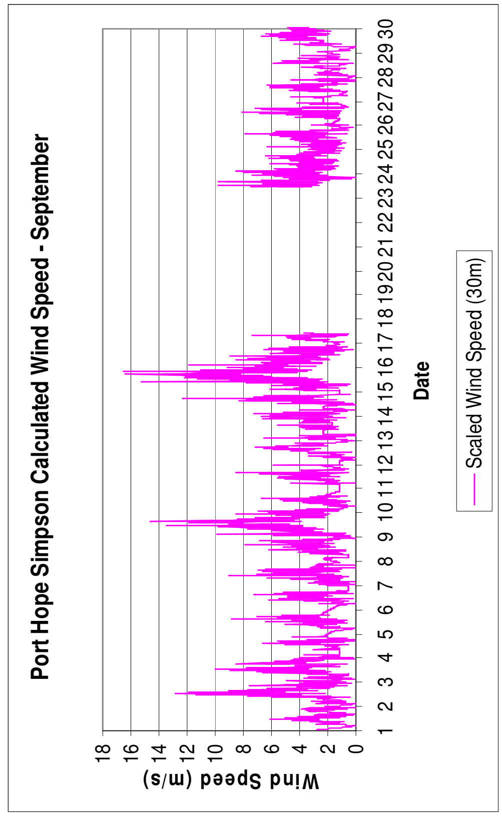

Port Hope Simpson Measured Wind Speed - July
Wind Speed (m/s)
Date
Measured Wind Speed (9m)

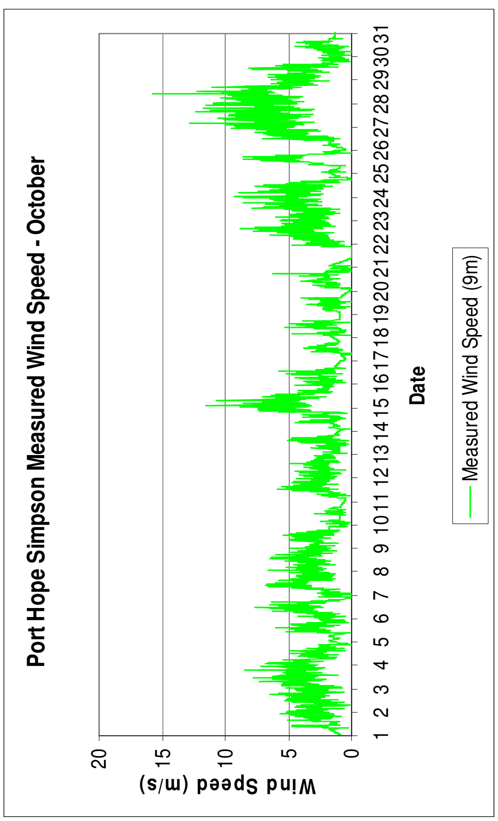

Port Hope Simpson Calculated Wind Speed - July
Wind Speed (m/s)
Date
Scaled Wind Speed (30m)

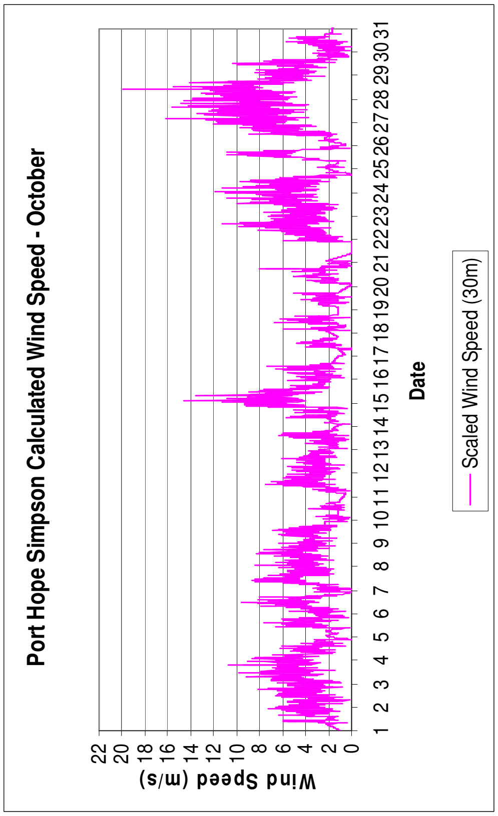

Port Hope Simpson Measured Wind Speed - August
Wind Speed (m/s)
Date
Measured Wind Speed (9m)

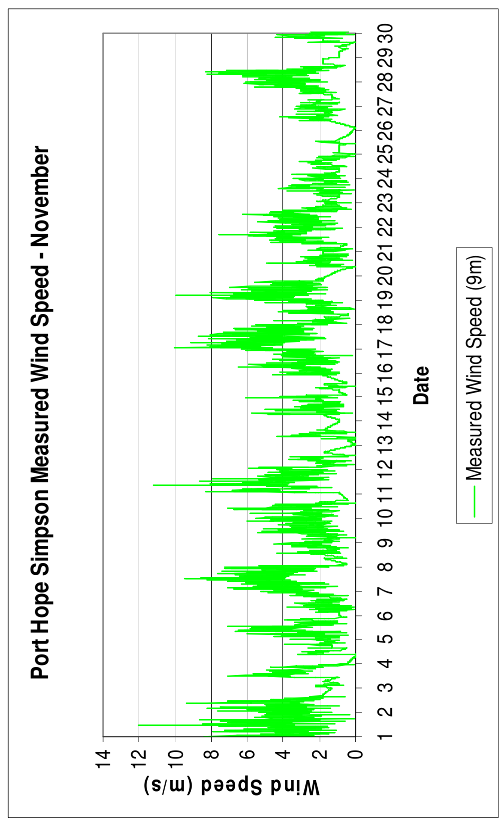

Port Hope Simpson Calculated Wind Speed - August
Wind Speed (m/s)
Date
Scaled Wind Speed (30m)

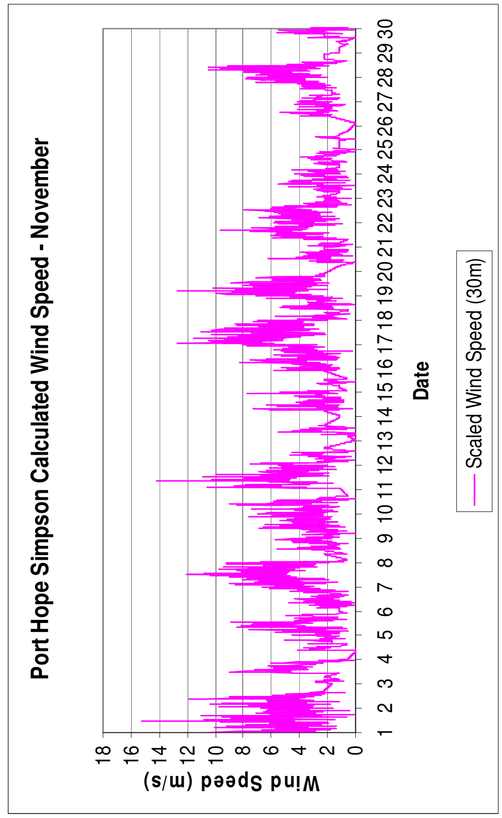

Port Hope Simpson Measured Wind Speed - September
Wind Speed (m/s)
Date
Measured Wind Speed (9m)

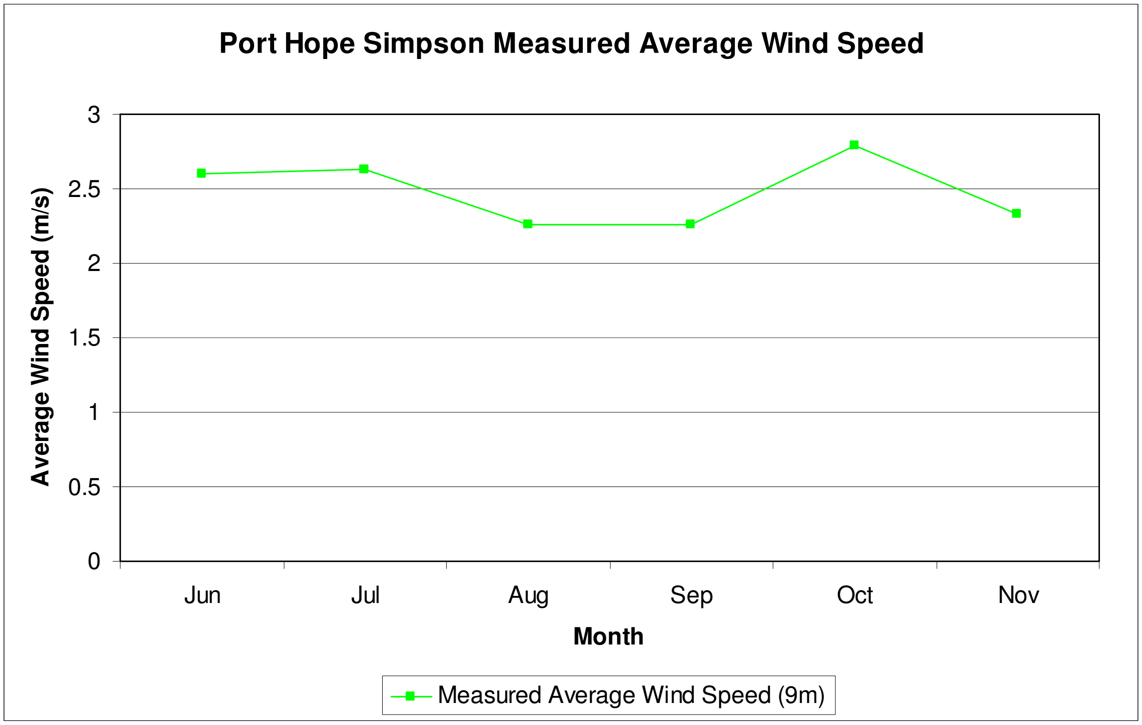

Port Hope Simpson Calculated Wind Speed - September
Wind Speed (m/s)
Date
Scaled Wind Speed (30m)

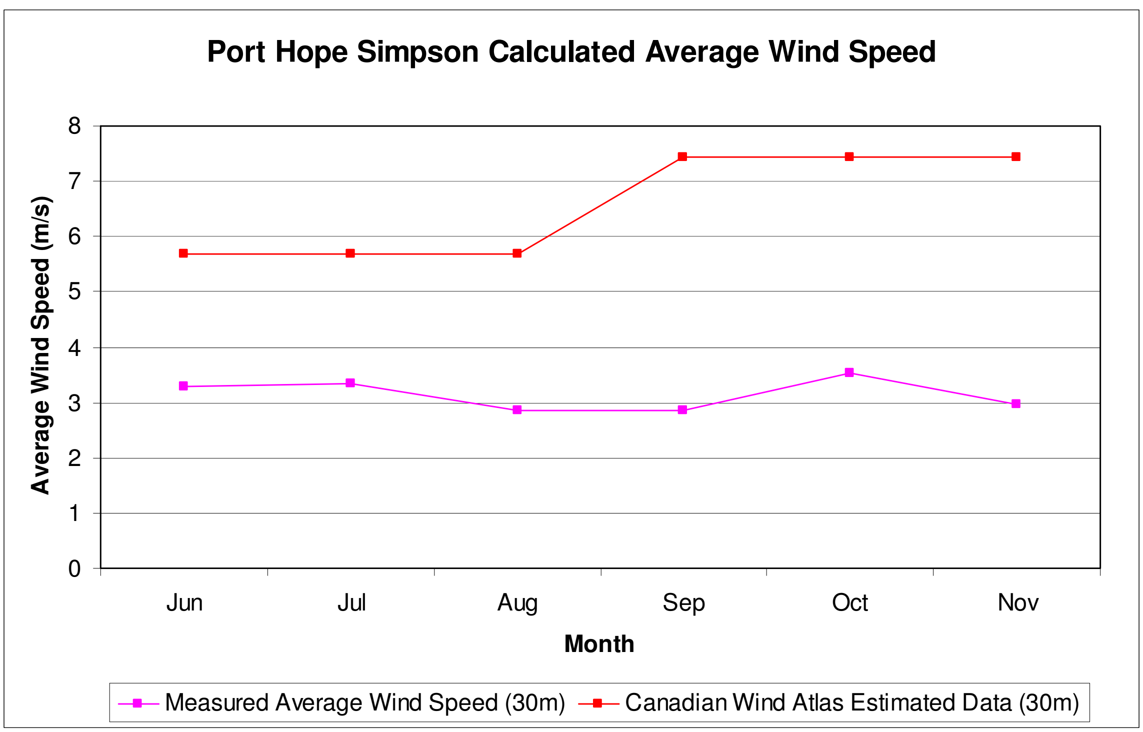

Port Hope Simpson Measured Wind Speed - October
Wind Speed (m/s)
Date
Measured Wind Speed (9m)

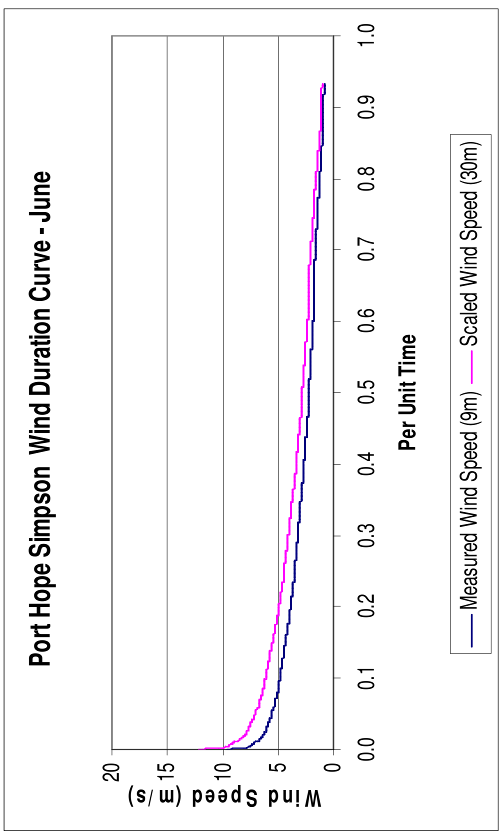

Port Hope Simpson Calculated Wind Speed - October
Wind Speed (m/s)
Date
Scaled Wind Speed (30m)

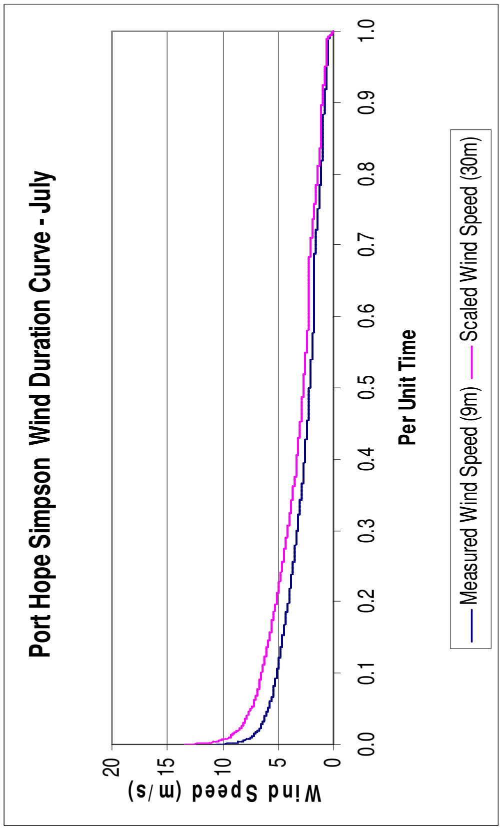

Port Hope Simpson Measured Wind Speed - November
Wind Speed (m/s)
Date
Measured Wind Speed (9m)

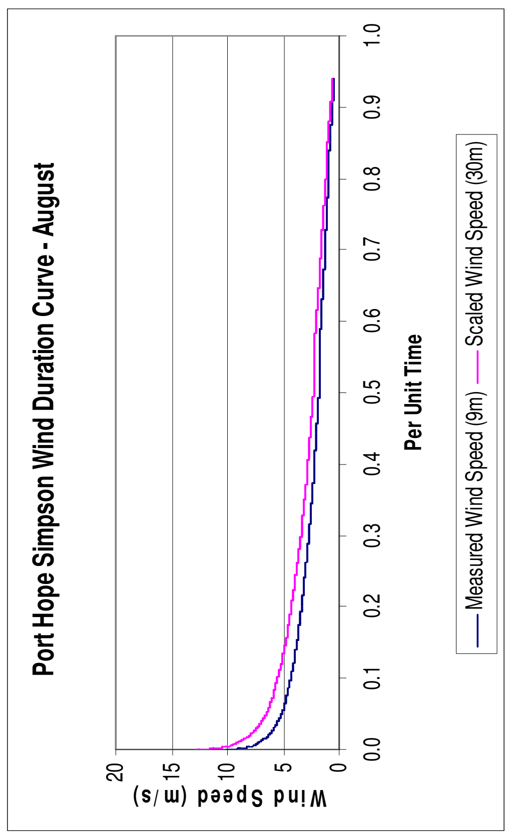

Port Hope Simpson Calculated Wind Speed - November
Wind Speed (m/s)
Date
Scaled Wind Speed (30m)

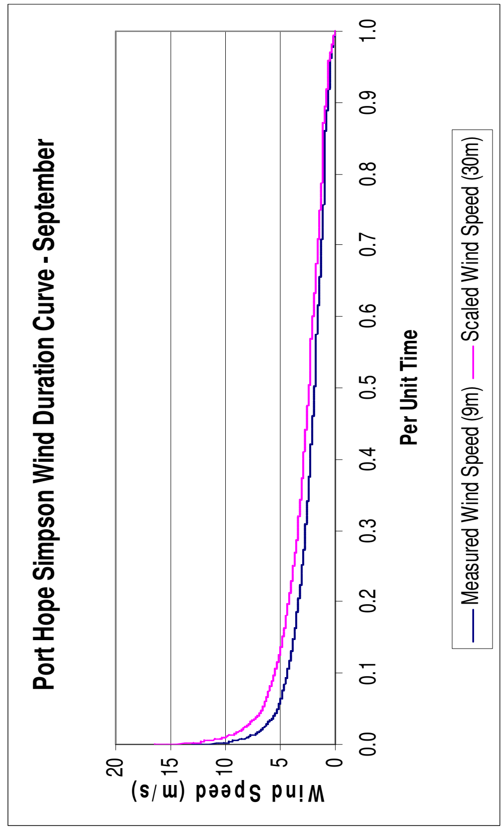

Port Hope Simpson Measured Average Wind Speed
Average Wind Speed (m/s)
3
2.5
2
1.5
1
0.5
0
Jun
Jul
Aug
Sep
Oct
Nov
Month
Measured Average Wind Speed (9m)

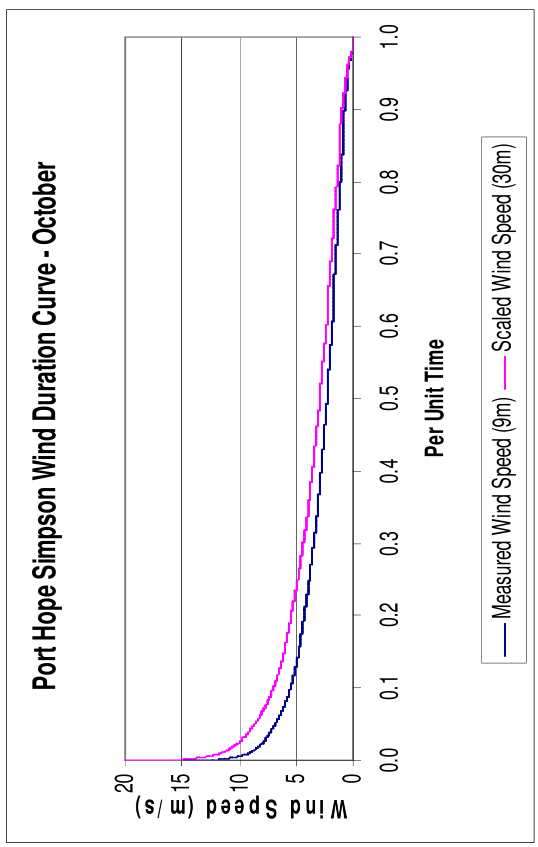

Port Hope Simpson Calculated Average Wind Speed
Average Wind Speed (m/s)
8
7
6
5
4
3
2
1
0
Jun
Jul
Aug
Sep
Oct
Nov
Month
Measured Average Wind Speed (30m)
Canadian Wind Atlas Estimated Data (30m)

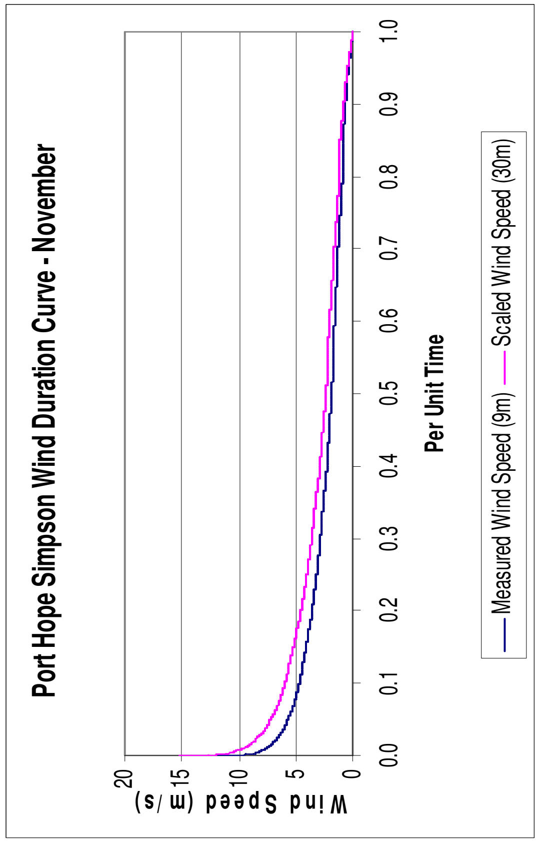

Port Hope Simpson Wind Duration Curve - June
Wind Speed (m/s)
20
15
10
5
0
0.0
0.1
0.2
0.3
0.4
0.5
0.6
0.7
0.8
0.9
1.0
Per Unit Time
Measured Wind Speed (9m)
Scaled Wind Speed (30m)

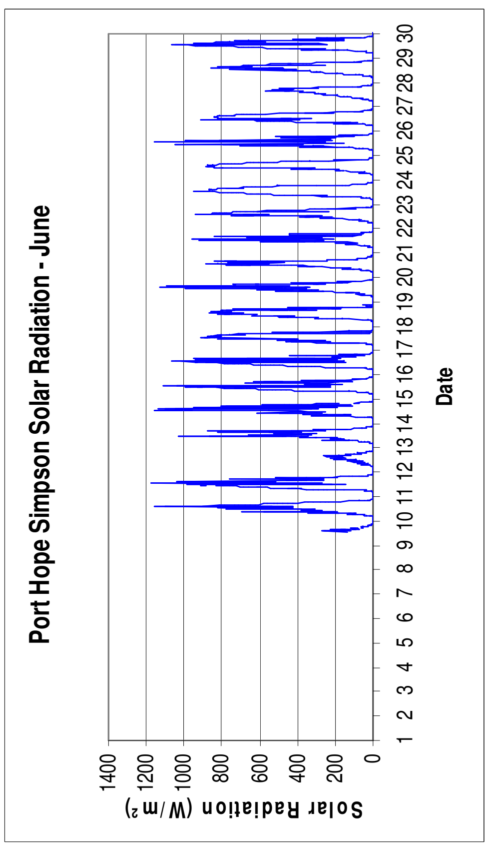

Port Hope Simpson Wind Duration Curve - July
Wind Speed (m/s)
20
15
10
5
0
0.0
0.1
0.2
0.3
0.4
0.5
0.6
0.7
0.8
0.9
1.0
Per Unit Time
Measured Wind Speed (9m)
Scaled Wind Speed (30m)

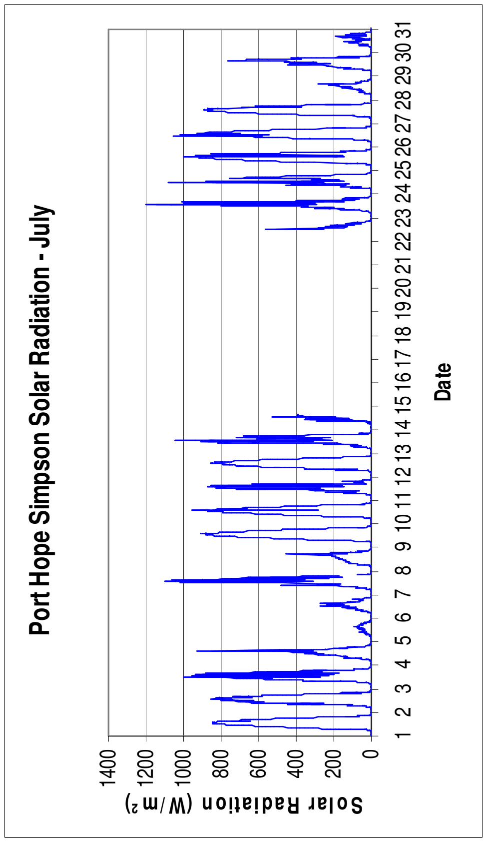

Port Hope Simpson Wind Duration Curve - August
Wind Speed (m/s)
20
15
10
5
0
0.0
0.1
0.2
0.3
0.4
0.5
0.6
0.7
0.8
0.9
1.0
Per Unit Time
Measured Wind Speed (9m)
Scaled Wind Speed (30m)

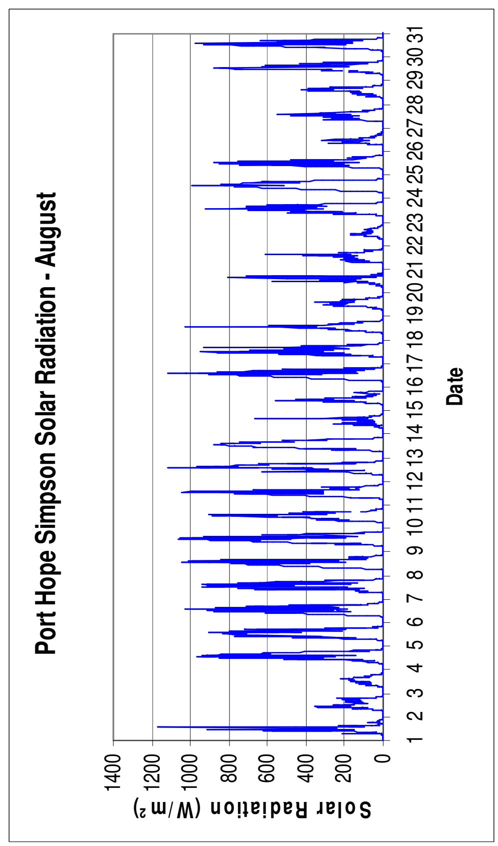

Port Hope Simpson Wind Duration Curve - September
Wind Speed (m/s)
20
15
10
5
0
0.0
0.1
0.2
0.3
0.4
0.5
0.6
0.7
0.8
0.9
1.0
Per Unit Time
Measured Wind Speed (9m)
Scaled Wind Speed (30m)

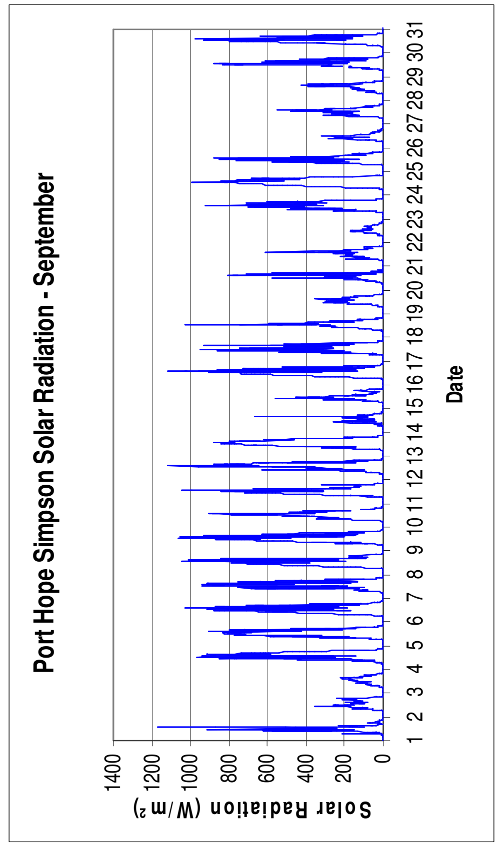

Port Hope Simpson Wind Duration Curve - October
Wind Speed (m/s)
20
15
10
5
0
0.0
0.1
0.2
0.3
0.4
0.5
0.6
0.7
0.8
0.9
1.0
Per Unit Time
Measured Wind Speed (9m)
Scaled Wind Speed (30m)

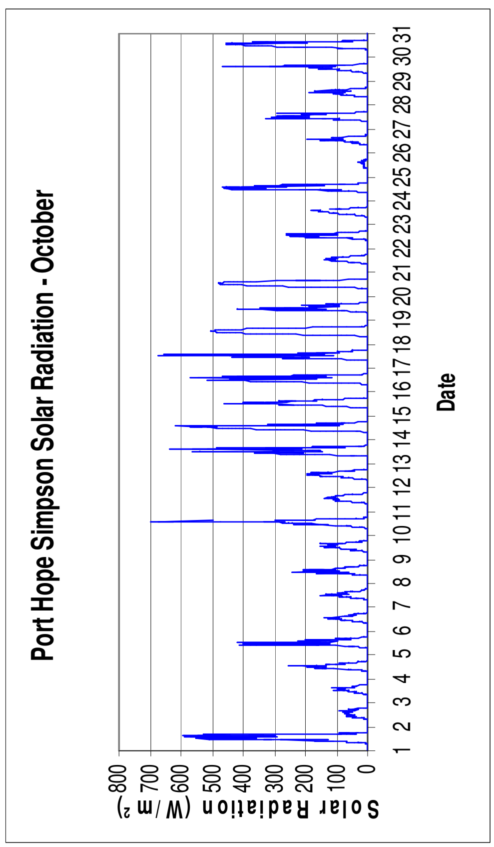

Port Hope Simpson Wind Duration Curve - November
Wind Speed (m/s)
20
15
10
5
0
0.0
0.1
0.2
0.3
0.4
0.5
0.6
0.7
0.8
0.9
1.0
Per Unit Time
Measured Wind Speed (9m)
Scaled Wind Speed (30m)

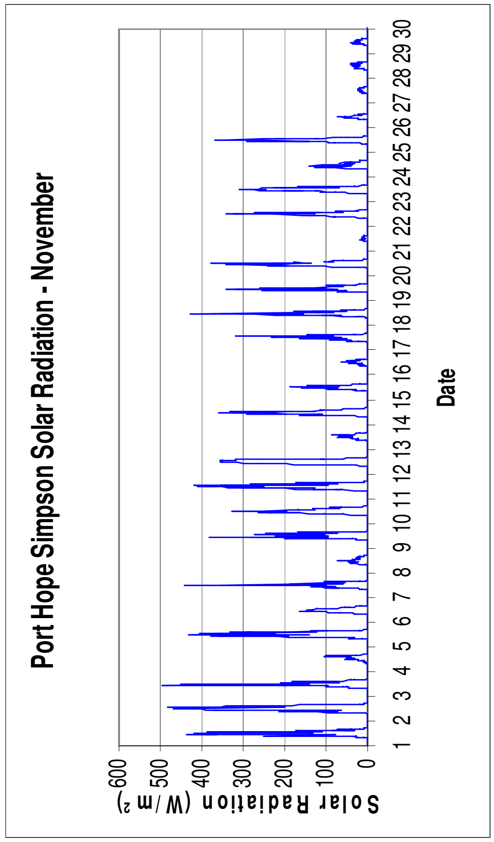

Port Hope Simpson Solar Radiation - June
Solar Radiation (W/m²)
Date

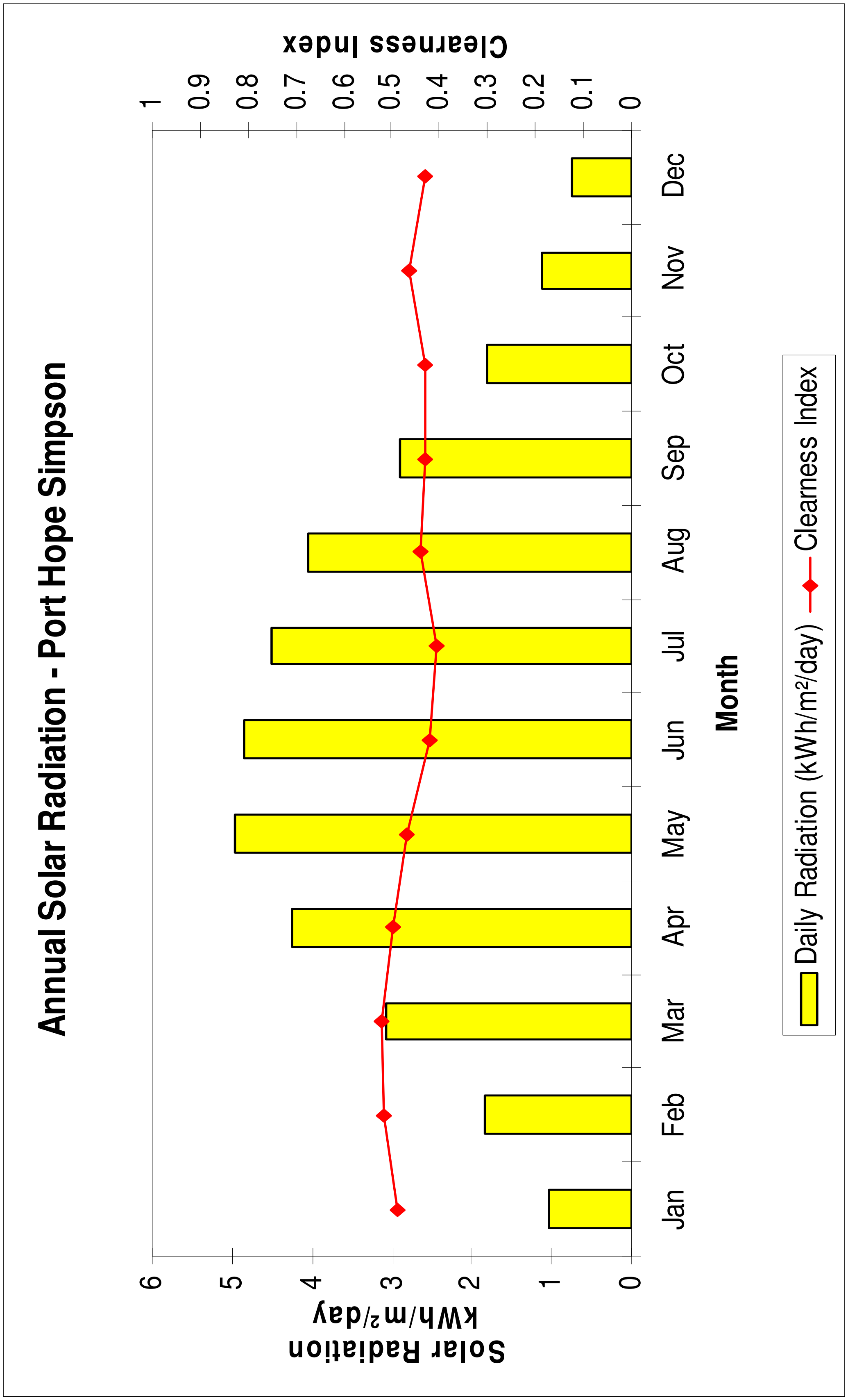

Port Hope Simpson Solar Radiation - July
Solar Radiation (W/m²)
Date

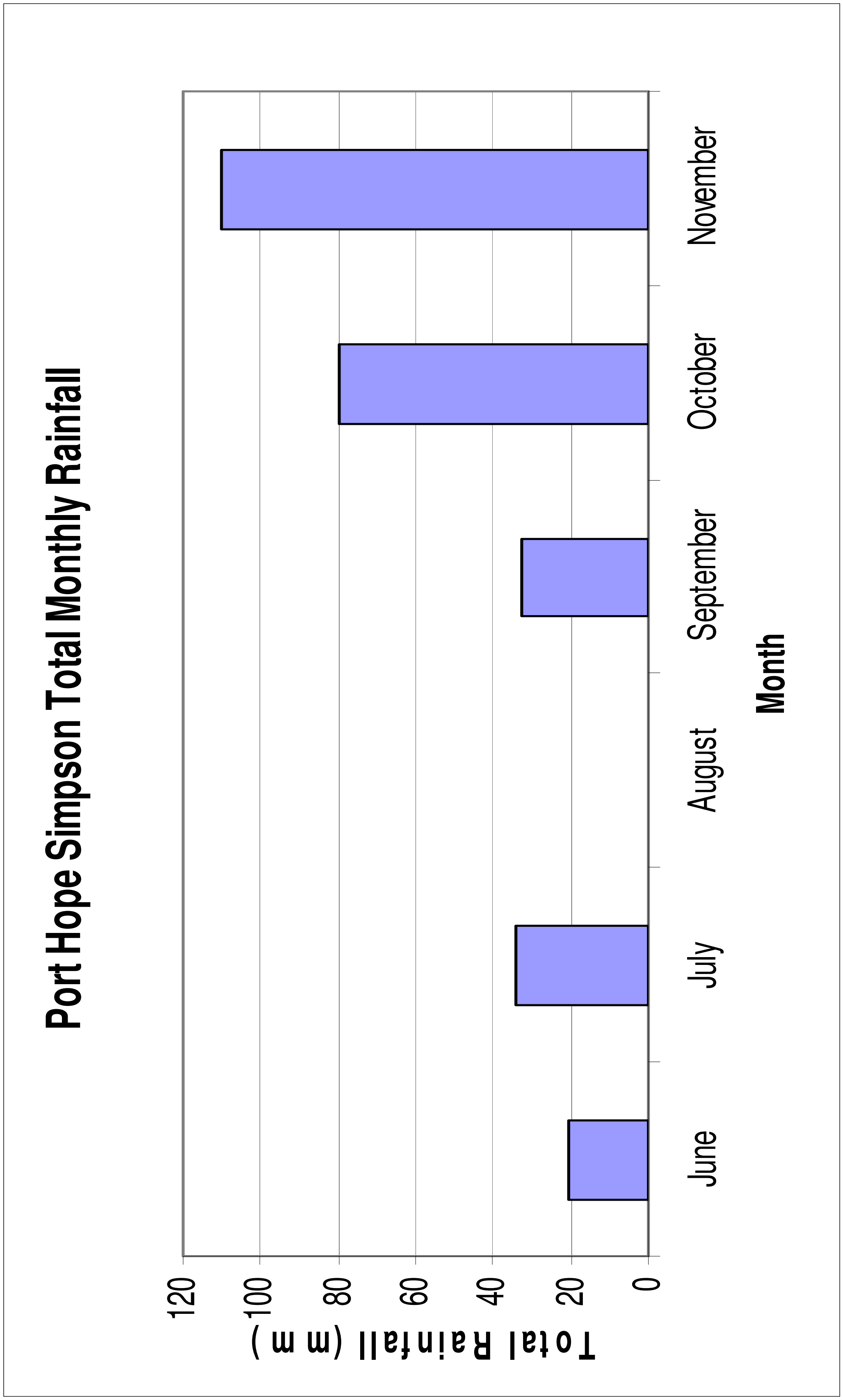

Port Hope Simpson Solar Radiation - August
Solar Radiation (W/m²)
Date


Port Hope Simpson Solar Radiation - September
Solar Radiation (W/m²)
Date


Port Hope Simpson Solar Radiation - October
Solar Radiation (W/m²)
Date


Port Hope Simpson Solar Radiation - November
Solar Radiation (W/m²)
Date


Annual Solar Radiation - Port Hope Simpson
Solar Radiation
kWh/m²/day
Clearness Index
0
1
2
3
4
5
6
0
0.1
0.2
0.3
0.4
0.5
0.6
0.7
0.8
0.9
1
Jan
Feb
Mar
Apr
May
Jun
Jul
Aug
Sep
Oct
Nov
Dec
Month
Daily Radiation (kWh/m²/day)
Clearness Index

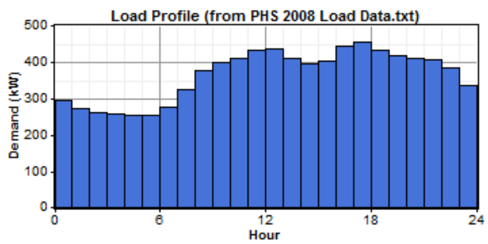

Port Hope Simpson Total Monthly Rainfall
Total Rainfall (mm)
120
100
80
60
40
20
0
June
July
August
September
October
November
Month

HOMER Input Summary

File name: PortHopeSimpson.hmr
File version: 2.68 beta
Author:
Notes:

AC Load: Port Hope Simpson Net System Load

Data source:	PHS 2008 Load Data.txt
Daily noise:	12.2%
Hourly noise:	30.2%
Scaled annual average:	9,178, 9,362, 9,518, 9,674, 9,827 kWh/d
Scaled peak load:	810, 826, 840, 854, 867 kW
Load factor:	0.472



PV

Size (kW)	Capital ($)	Replacement ($)	O&M ($/yr)
50.000	400,000	400,000	10,000
100.000	750,000	750,000	15,000

Sizes to consider:	0, 50, 100 kW
Lifetime:	20 yr
Derating factor:	80%
Tracking system:	No Tracking
Slope:	52.5 deg
Azimuth:	0 deg
Ground reflectance:	20%

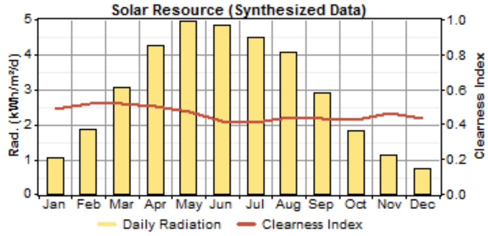
Solar Resource

Latitude: 52 degrees 33 minutes North
Longitude: 56 degrees 18 minutes West
Time zone: GMT -3:30

Data source: Synthetic

Month	Clearness Index	Average Radiation
		(kWh/m^2/day)
Jan	0.486	1.030
Feb	0.519	1.850
Mar	0.521	3.060
Apr	0.500	4.250
May	0.470	4.970
Jun	0.422	4.850
Jul	0.409	4.510
Aug	0.439	4.060
Sep	0.431	2.910
Oct	0.430	1.820
Nov	0.464	1.130
Dec	0.431	0.740

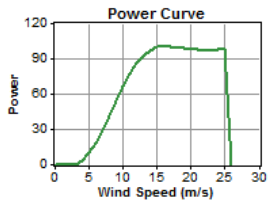
Scaled annual average: 2.92 kWh/m²/d



AC Wind Turbine: Northern Power NW100/21

Quantity	Capital ($)	Replacement ($)	O&M ($/yr)
1	500,000	400,000	10,000

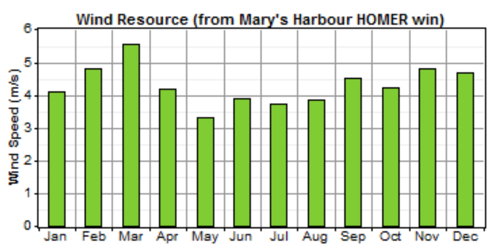
Quantities to consider: 0, 1, 2, 3, 4, 5, 6, 7, 8, 9, 10
Lifetime: 20 yr
Hub height: 37 m



Wind Resource

Data source: Mary's Harbour HOMER wind speeds.txt

Month	Wind Speed (m/s)
Jan	4.11
Feb	4.78
Mar	5.56
Apr	4.18
May	3.30
Jun	3.89
Jul	3.71
Aug	3.83
Sep	4.51
Oct	4.22
Nov	4.80
Dec	4.69



Weibull k: 1.60
Autocorrelation factor: 0.861
Diurnal pattern strength: 0.0797
Hour of peak wind speed: 10
Scaled annual average: 4.29 m/s
Anemometer height: 9 m
Altitude: 5 m

Wind shear profile: Logarithmic
Surface roughness length: 0.01 m

AC Hydro:

Capital cost: $ 32,387,000, 58,695,000, 15,434,000, 1,700,000, 4,092,000, 3,741,000, 1,700,000, 3,400,000, 2,600,000
Replacement cost: $ 0
O&M cost: $ 283,170, 409,810, 147,320, 6,960, 12,640, 11,020, 4,170, 7,190, 3,710/yr
Lifetime: 60 yr
Available head: 28, 40, 60, 11, 40, 8, 95, 5, 7 m
Design flow rate: 23,030, 23,340, 2,230, 1,010, 500, 2,180, 70, 2,260, 830 L/s
Min. flow ratio: 15, 10, 10, 15, 10, 15, 5, 15, 15%
Max. flow ratio: 100%
Turbine efficiency: 85%
Pipe head loss: 0%

Consider systems without hydro: Yes

Hydro Resource

Data source: Synthetic

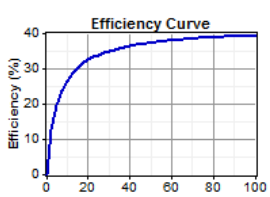
Month	Stream Flow (L/s)
Jan	2,294
Feb	1,471
Mar	1,647
Apr	4,588
May	4,706
Jun	4,588
Jul	4,706
Aug	4,706
Sep	4,588
Oct	4,706
Nov	4,588
Dec	3,824

Residual flow: 0 L/s
Scaled annual average: 3,879, 5,631, 795, 67, 120, 104, 40, 68, 54 L/s

AC Generator: 2073

Size (kW)	Capital ($)	Replacement ($)	O&M ($/hr)
455.000	0	400,000	1.684

Sizes to consider: 455 kW
Lifetime: 100,000 hrs
Min. load ratio: 30%
Heat recovery ratio: 0%
Fuel used: #1 Diesel Arctic Grade
Fuel curve intercept: 0.0132 L/hr/kW
Fuel curve slope: 0.233 L/hr/kW

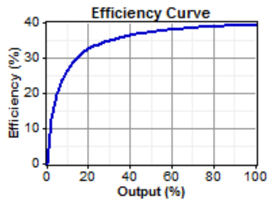


AC Generator: 2042

Size (kW)	Capital ($)	Replacement ($)	O&M ($/hr)

455.000	0	400,000	1.684

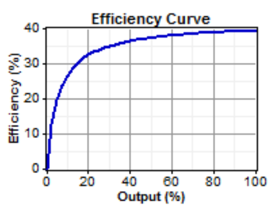
Sizes to consider: 455 kW
Lifetime: 100,000 hrs
Min. load ratio: 30%
Heat recovery ratio: 0%
Fuel used: #1 Diesel Arctic Grade
Fuel curve intercept: 0.0132 L/hr/kW
Fuel curve slope: 0.233 L/hr/kW



AC Generator: 2043

Size (kW)	Capital ($)	Replacement ($)	O&M ($/hr)
455.000	0	400,000	1.684

Sizes to consider: 455 kW
Lifetime: 100,000 hrs
Min. load ratio: 30%
Heat recovery ratio: 0%
Fuel used: #1 Diesel Arctic Grade
Fuel curve intercept: 0.0132 L/hr/kW
Fuel curve slope: 0.233 L/hr/kW



Fuel: #1 Diesel Arctic Grade

Price: $ 0.945, 0.944, 0.963, 0.993, 0.993/L
Lower heating value: 45.8 MJ/kg
Density: 809 kg/m3
Carbon content: 88.0%
Sulfur content: 0.0500%

Converter

Size (kW)	Capital ($)	Replacement ($)	O&M ($/yr)
100.000	64,000	64,000	6,400

Sizes to consider: 0, 100 kW
Lifetime: 15 yr
Inverter efficiency: 90%
Inverter can parallel with AC generator: Yes
Rectifier relative capacity: 100%
Rectifier efficiency: 85%

Economics

Annual real interest rate: 8%
Project lifetime: 60 yr
Capacity shortage penalty: $ 0/kWh
System fixed capital cost: $ 0

System fixed O&M cost: $ 0/yr

Generator control

Check load following: Yes
Check cycle charging: No

Allow systems with multiple generators:	Yes
Allow multiple generators to operate simultaneously:	Yes
Allow systems with generator capacity less than peak load:	No

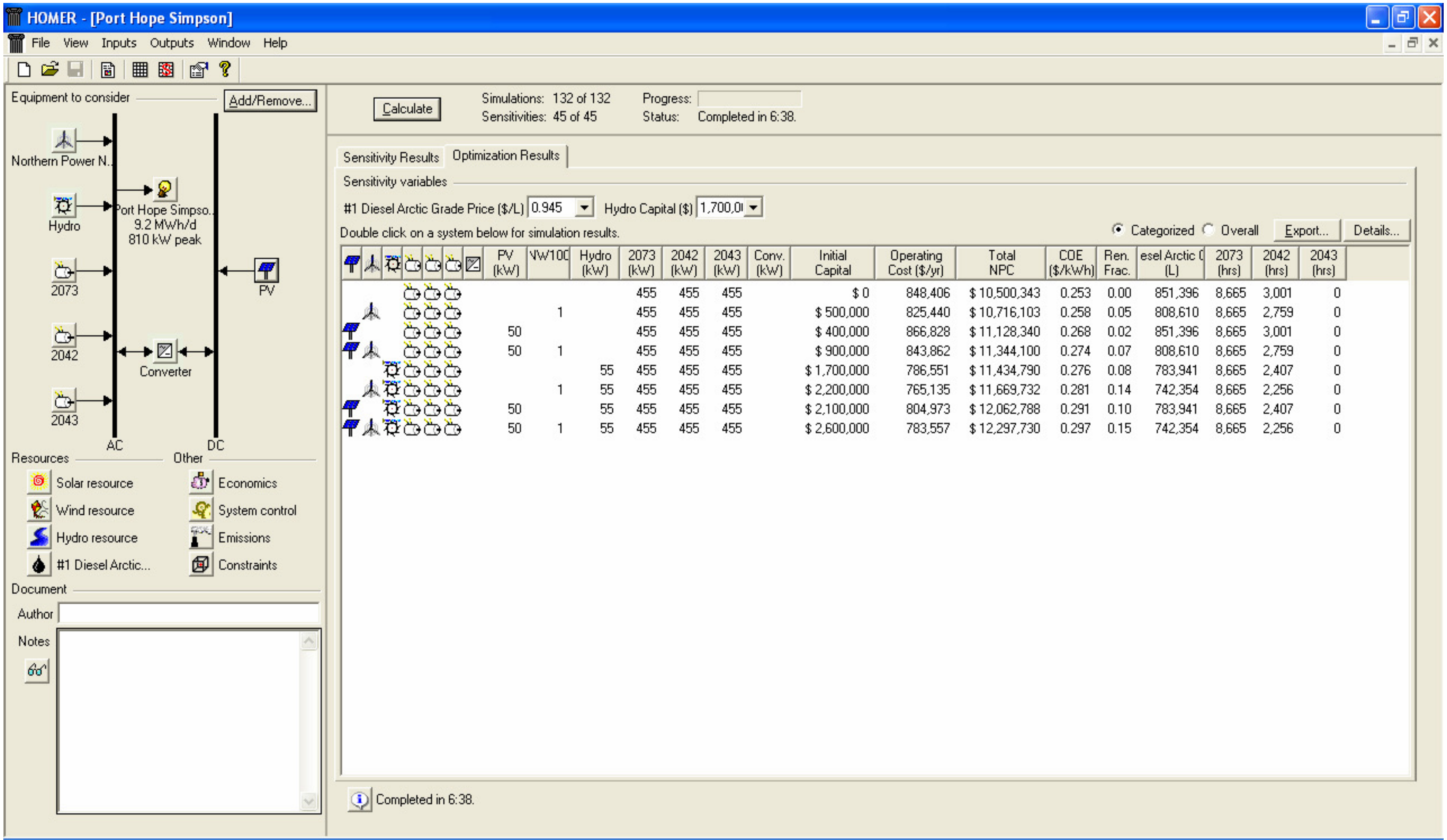
Emissions

Carbon dioxide penalty:	$ 0/t
Carbon monoxide penalty:	$ 0/t
Unburned hydrocarbons penalty:	$ 0/t
Particulate matter penalty:	$ 0/t
Sulfur dioxide penalty:	$ 0/t
Nitrogen oxides penalty:	$ 0/t

Constraints

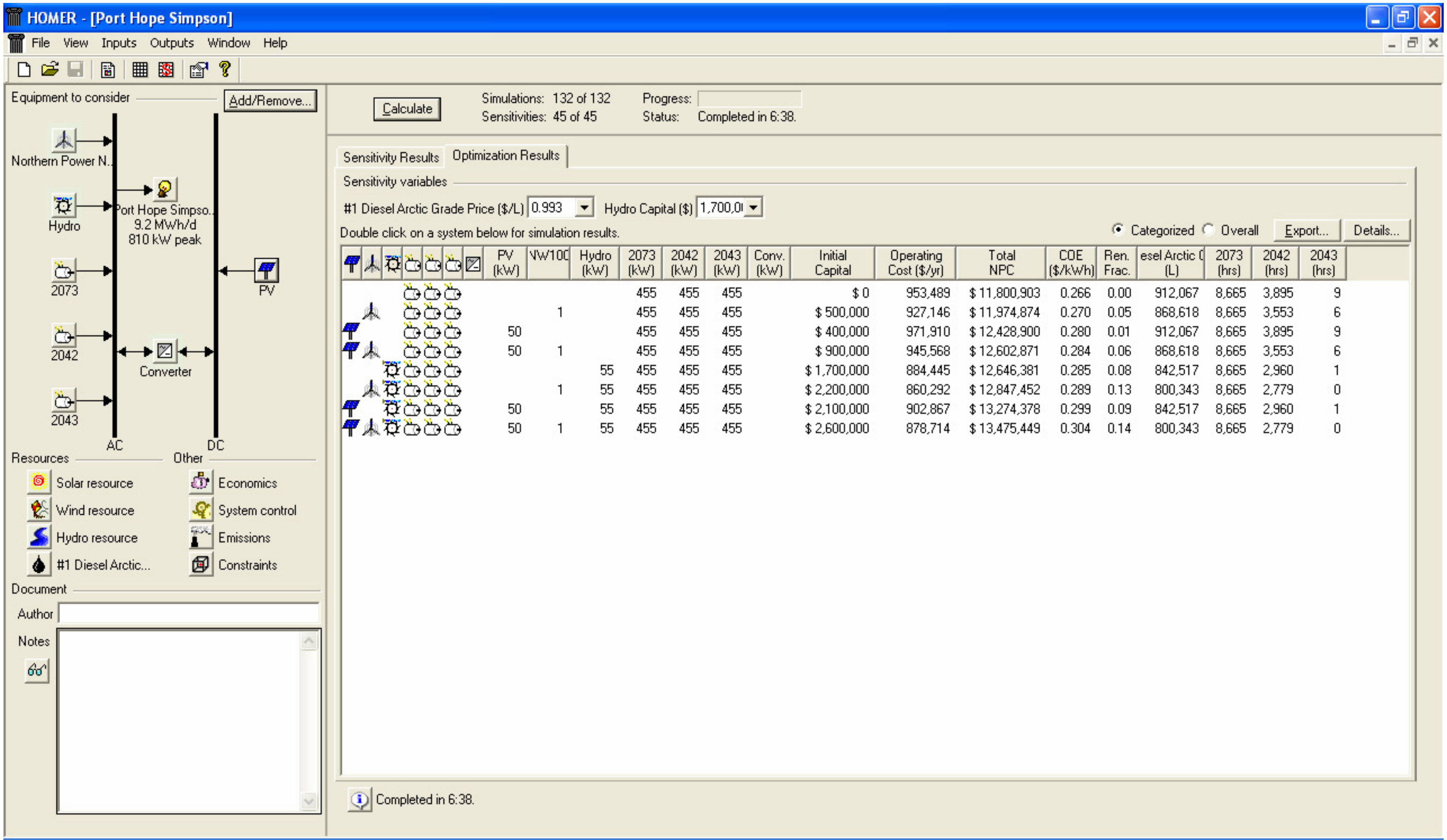
Maximum annual capacity shortage:	0%
Minimum renewable fraction:	0%

Operating reserve as percentage of hourly load:	10%
Operating reserve as percentage of peak load:	0%
Operating reserve as percentage of solar power output:	25%
Operating reserve as percentage of wind power output:	50%



PV (kW)	NW100	Hydro (kW)	2073 (kW)	2042 (kW)	2043 (kW)	Conv. (kW)	Initial Capital	Operating Cost ($/yr)	Total NPC	COE ($/kWh)	Ren. Frac.	esel Arctic (L)	2073 (hrs)	2042 (hrs)	2043 (hrs)
			455	455	455		$ 0	848,406	$ 10,500,343	0.253	0.00	851,396	8,665	3,001	0
	1		455	455	455		$ 500,000	825,440	$ 10,716,103	0.258	0.05	808,610	8,665	2,759	0
50			455	455	455		$ 400,000	866,828	$ 11,128,340	0.268	0.02	851,396	8,665	3,001	0
50	1		455	455	455		$ 900,000	843,862	$ 11,344,100	0.274	0.07	808,610	8,665	2,759	0
		55	455	455	455		$ 1,700,000	786,551	$ 11,434,790	0.276	0.08	783,941	8,665	2,407	0
	1	55	455	455	455		$ 2,200,000	765,135	$ 11,669,732	0.281	0.14	742,354	8,665	2,256	0
50		55	455	455	455		$ 2,100,000	804,973	$ 12,062,788	0.291	0.10	783,941	8,665	2,407	0
50	1	55	455	455	455		$ 2,600,000	783,557	$ 12,297,730	0.297	0.15	742,354	8,665	2,256	0

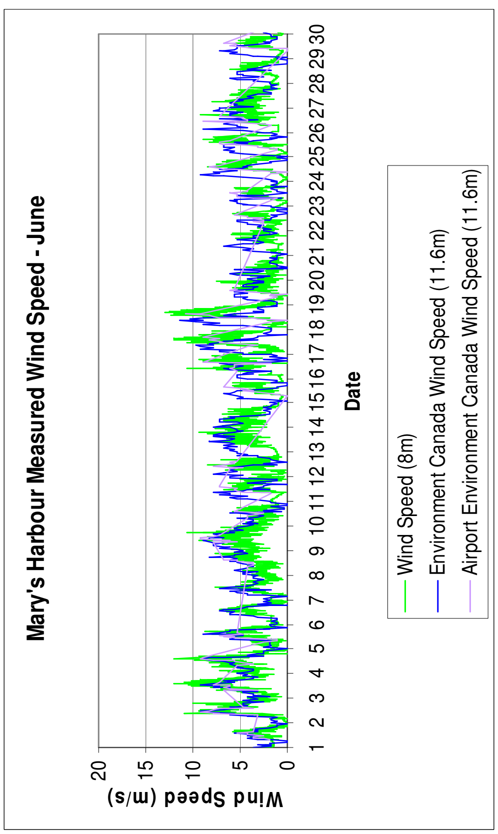
Port Hope Simspon HOMER Results – 2011 System Load

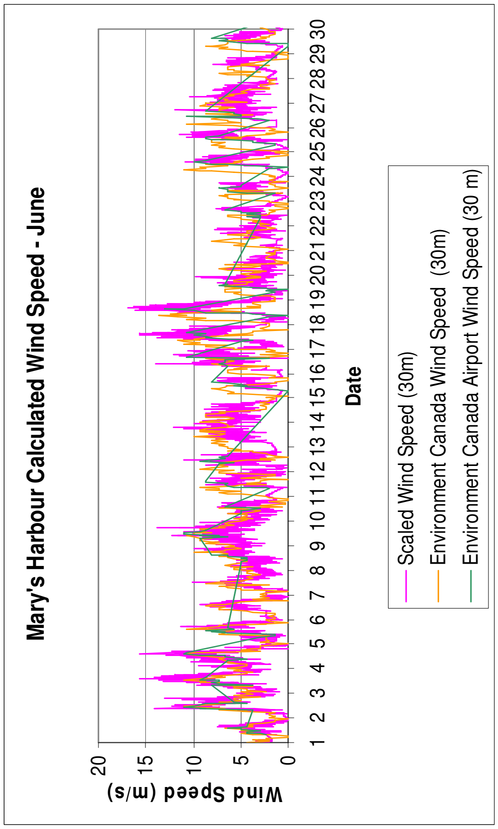


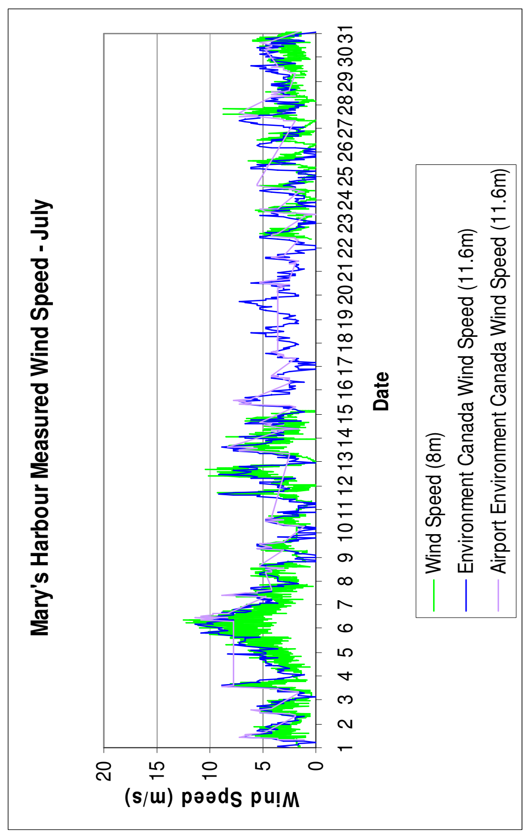
PV (kW)	NW100	Hydro (kW)	2073 (kW)	2042 (kW)	2043 (kW)	Conv. (kW)	Initial Capital	Operating Cost ($/yr)	Total NPC	COE ($/kWh)	Ren. Frac.	esel Arctic ((L)	2073 (hrs)	2042 (hrs)	2043 (hrs)
			455	455	455		$ 0	953,489	$ 11,800,903	0.266	0.00	912,067	8,665	3,895	9
	1		455	455	455		$ 500,000	927,146	$ 11,974,874	0.270	0.05	868,618	8,665	3,553	6
50			455	455	455		$ 400,000	971,910	$ 12,428,900	0.280	0.01	912,067	8,665	3,895	9
50	1		455	455	455		$ 900,000	945,568	$ 12,602,871	0.284	0.06	868,618	8,665	3,553	6
		55	455	455	455		$ 1,700,000	884,445	$ 12,646,381	0.285	0.08	842,517	8,665	2,960	1
	1	55	455	455	455		$ 2,200,000	860,292	$ 12,847,452	0.289	0.13	800,343	8,665	2,779	0
50		55	455	455	455		$ 2,100,000	902,867	$ 13,274,378	0.299	0.09	842,517	8,665	2,960	1
50	1	55	455	455	455		$ 2,600,000	878,714	$ 13,475,449	0.304	0.14	800,343	8,665	2,779	0

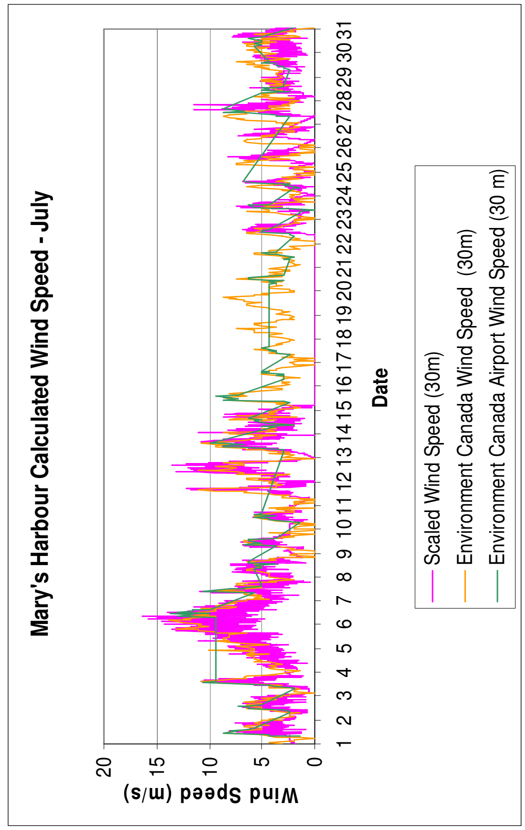
Port Hope Simpson HOMER Results – 2015 System Load

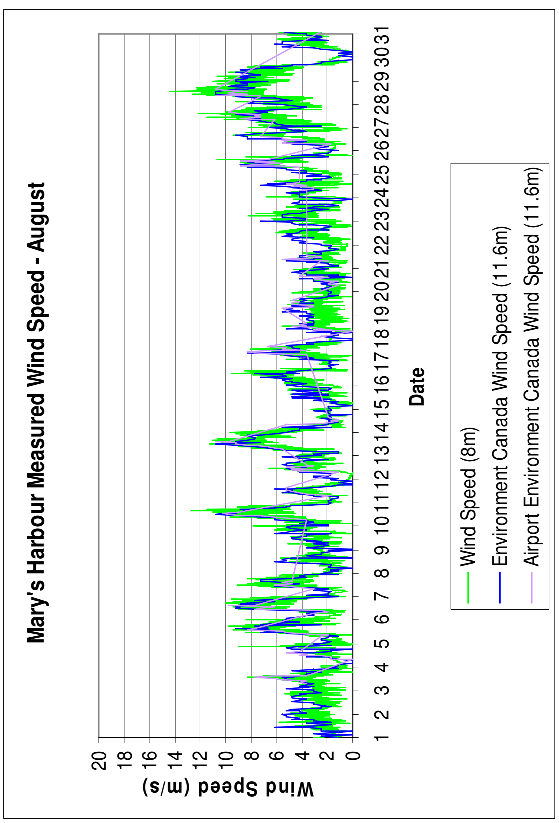
APPENDIX G – MARY'S HARBOUR

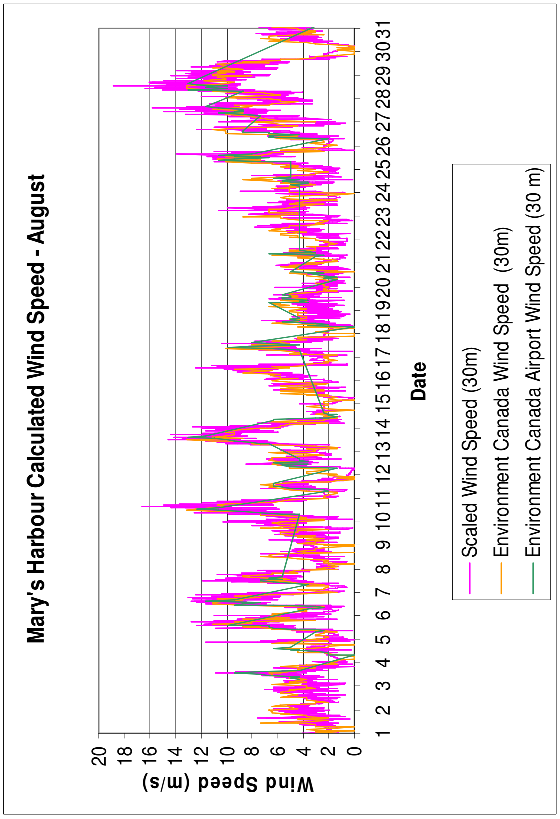

Mary's Harbour Measured Wind Speed - June
Wind Speed (m/s)
Date
Wind Speed (8m)
Environment Canada Wind Speed (11.6m)
Airport Environment Canada Wind Speed (11.6m)

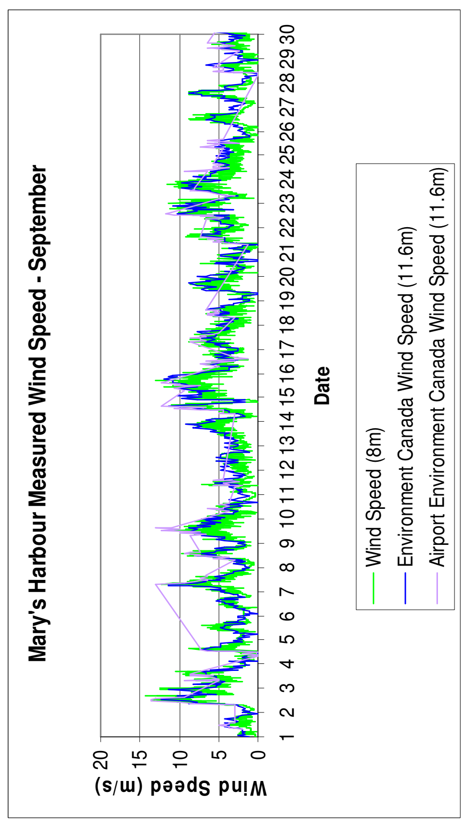

Mary's Harbour Calculated Wind Speed - June
Wind Speed (m/s)
Date
Scaled Wind Speed (30m)
Environment Canada Wind Speed (30m)
Environment Canada Airport Wind Speed (30 m)

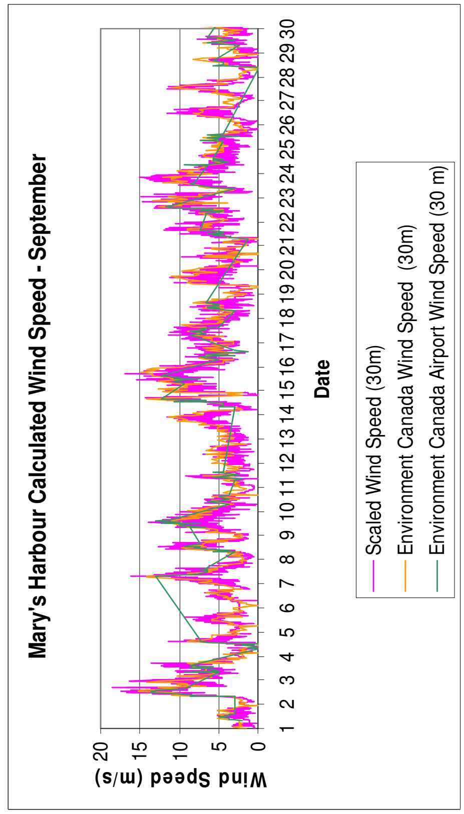

Mary's Harbour Measured Wind Speed - July
Wind Speed (m/s)
Date
Wind Speed (8m)
Environment Canada Wind Speed (11.6m)
Airport Environment Canada Wind Speed (11.6m)

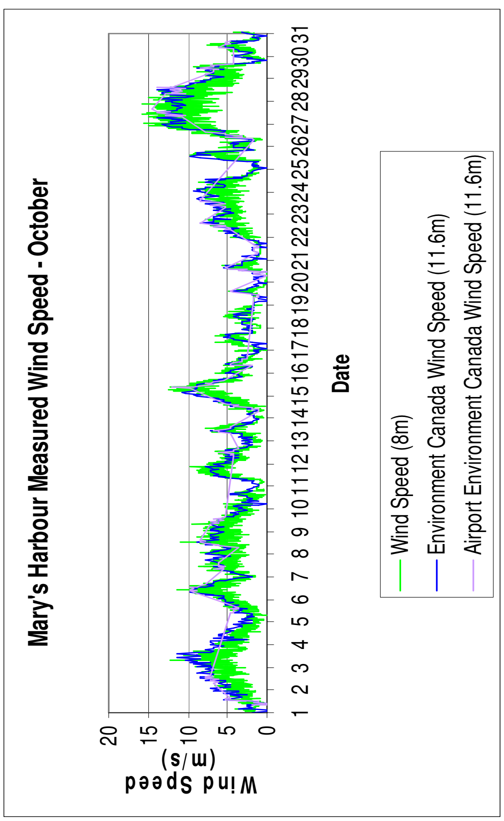

Mary's Harbour Calculated Wind Speed - July
Wind Speed (m/s)
Date
Scaled Wind Speed (30m)
Environment Canada Wind Speed (30m)
Environment Canada Airport Wind Speed (30 m)

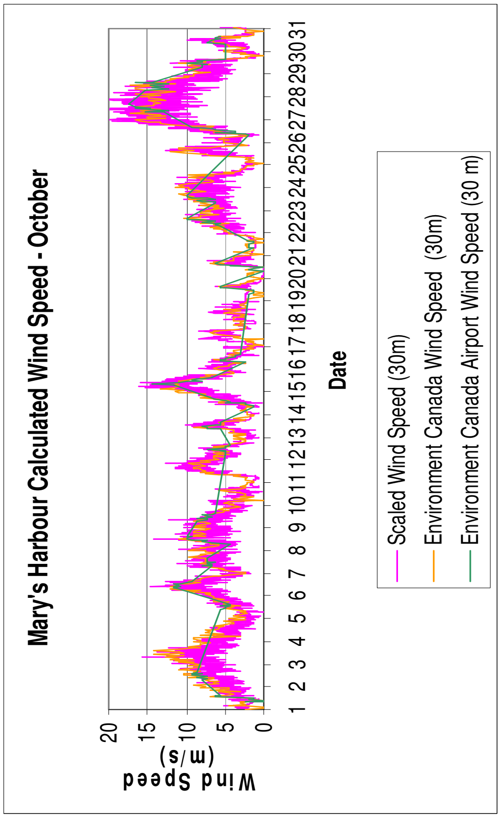

Mary's Harbour Measured Wind Speed - August
Wind Speed (m/s)
Date
Wind Speed (8m)
Environment Canada Wind Speed (11.6m)
Airport Environment Canada Wind Speed (11.6m)

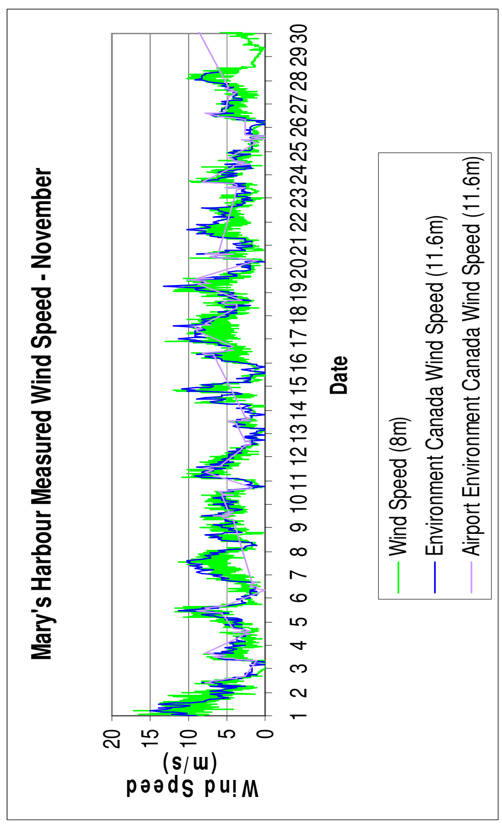

Mary's Harbour Calculated Wind Speed - August
Wind Speed (m/s)
Date
Scaled Wind Speed (30m)
Environment Canada Wind Speed (30m)
Environment Canada Airport Wind Speed (30 m)

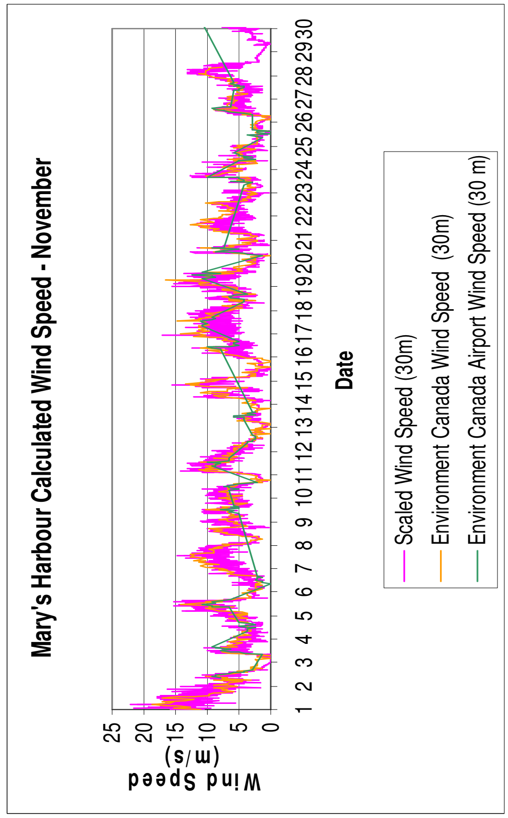

Mary's Harbour Measured Wind Speed - September
Wind Speed (m/s)
Date
Wind Speed (8m)
Environment Canada Wind Speed (11.6m)
Airport Environment Canada Wind Speed (11.6m)

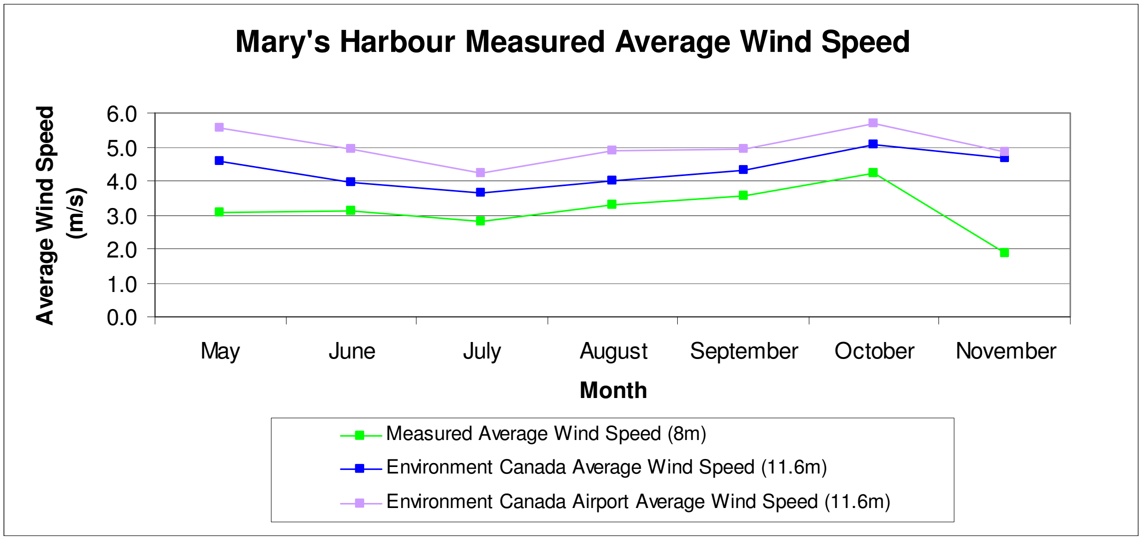

Mary's Harbour Calculated Wind Speed - September
Wind Speed (m/s)
Date
Scaled Wind Speed (30m)
Environment Canada Wind Speed (30m)
Environment Canada Airport Wind Speed (30 m)

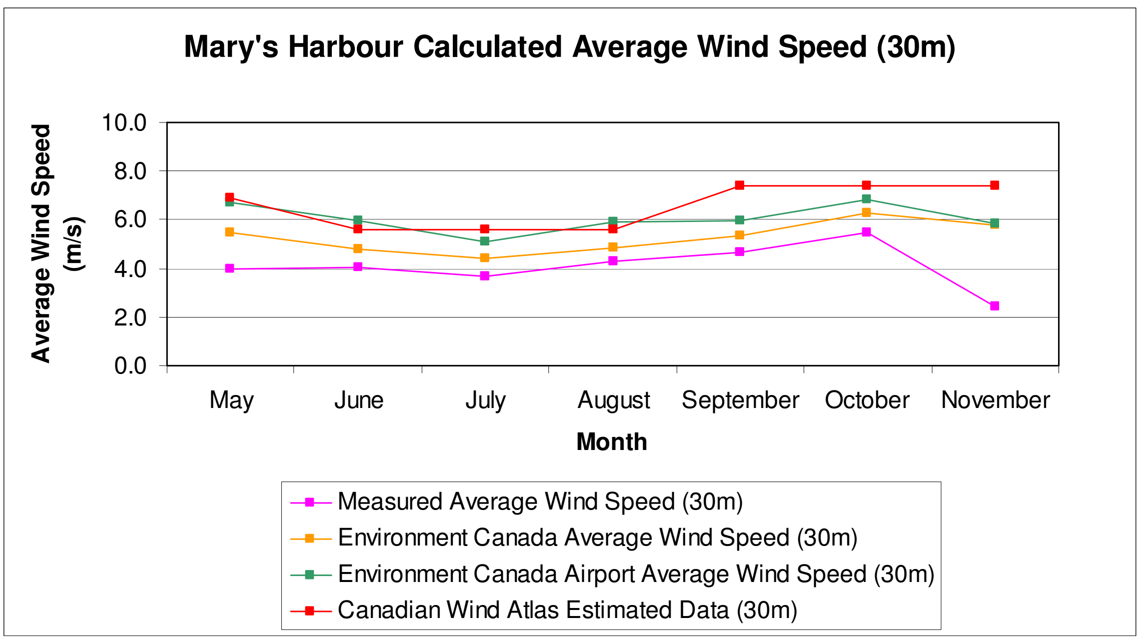

Mary's Harbour Measured Wind Speed - October
Wind Speed (m/s)
20
15
10
5
0
1 2 3 4 5 6 7 8 9 10 11 12 13 14 15 16 17 18 19 20 21 22 23 24 25 26 27 28 29 30 31
Date
Wind Speed (8m)
Environment Canada Wind Speed (11.6m)
Airport Environment Canada Wind Speed (11.6m)

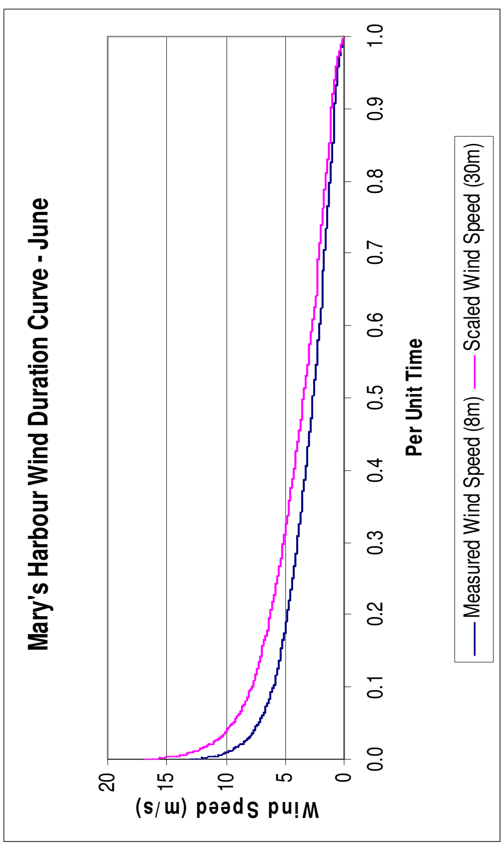

Mary's Harbour Calculated Wind Speed - October
Wind Speed (m/s)
20
15
10
5
0
1 2 3 4 5 6 7 8 9 10 11 12 13 14 15 16 17 18 19 20 21 22 23 24 25 26 27 28 29 30 31
Date
Scaled Wind Speed (30m)
Environment Canada Wind Speed (30m)
Environment Canada Airport Wind Speed (30 m)

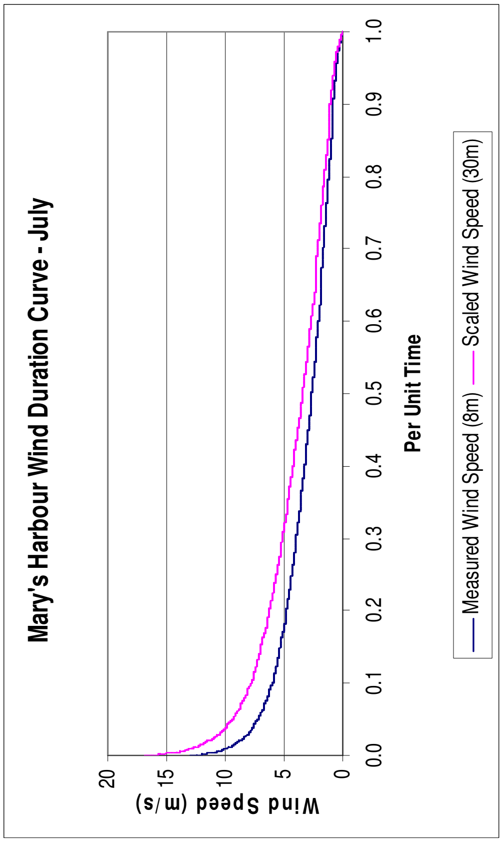

Mary's Harbour Measured Wind Speed - November
Wind Speed (m/s)
20
15
10
5
0
1 2 3 4 5 6 7 8 9 10 11 12 13 14 15 16 17 18 19 20 21 22 23 24 25 26 27 28 29 30
Date
Wind Speed (8m)
Environment Canada Wind Speed (11.6m)
Airport Environment Canada Wind Speed (11.6m)

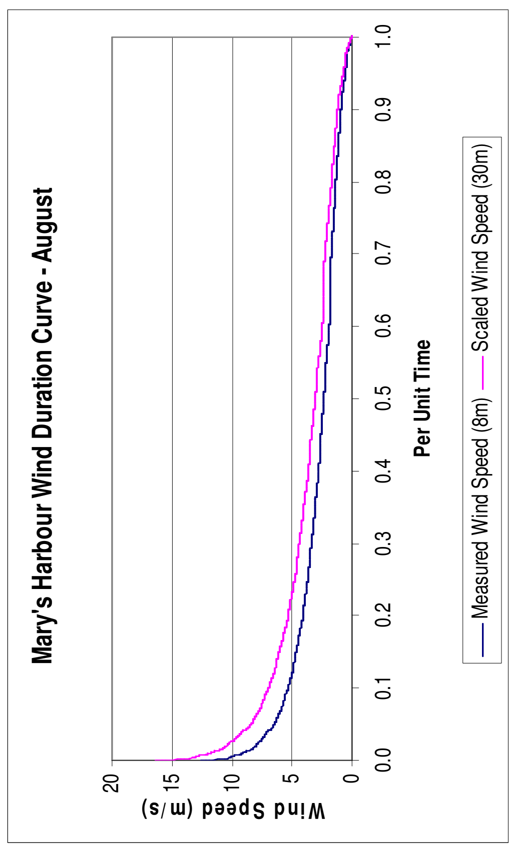

Mary's Harbour Calculated Wind Speed - November
Wind Speed (m/s)
25
20
15
10
5
0
1 2 3 4 5 6 7 8 9 10 11 12 13 14 15 16 17 18 19 20 21 22 23 24 25 26 27 28 29 30
Date
Scaled Wind Speed (30m)
Environment Canada Wind Speed (30m)
Environment Canada Airport Wind Speed (30 m)

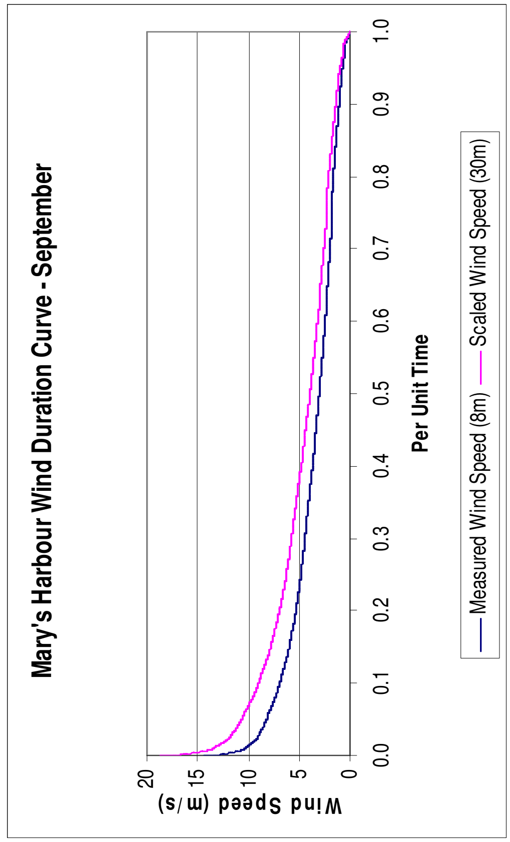

Mary's Harbour Measured Average Wind Speed
Average Wind Speed (m/s)
6.0
5.0
4.0
3.0
2.0
1.0
0.0
May
June
July
August
September
October
November
Month
Measured Average Wind Speed (8m)
Environment Canada Average Wind Speed (11.6m)
Environment Canada Airport Average Wind Speed (11.6m)

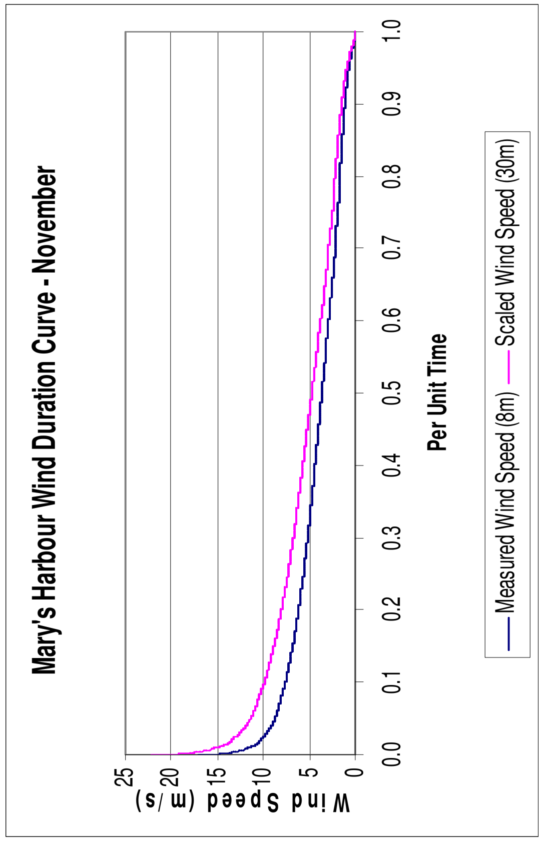

Mary's Harbour Calculated Average Wind Speed (30m)
Average Wind Speed (m/s)
10.0
8.0
6.0
4.0
2.0
0.0
May
June
July
August
September
October
November
Month
Measured Average Wind Speed (30m)
Environment Canada Average Wind Speed (30m)
Environment Canada Airport Average Wind Speed (30m)
Canadian Wind Atlas Estimated Data (30m)

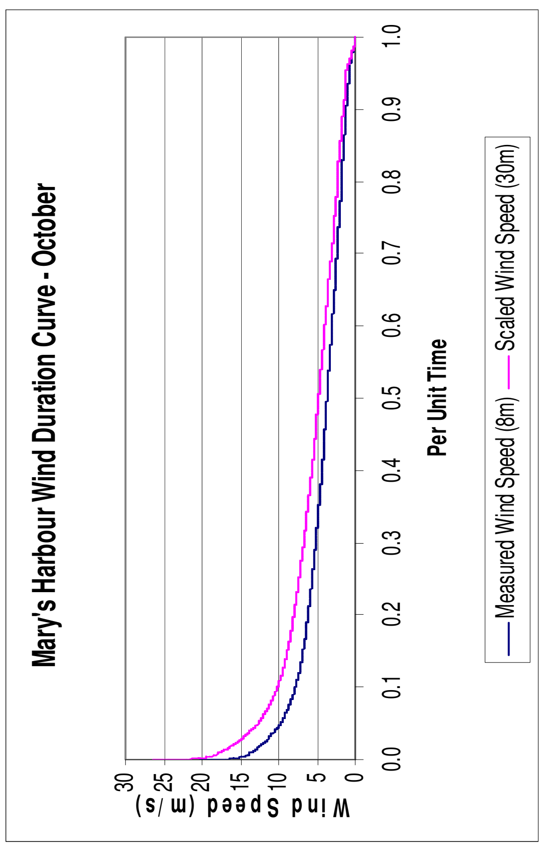

Mary's Harbour Wind Duration Curve - June
Wind Speed (m/s)
Per Unit Time
0.0
0.1
0.2
0.3
0.4
0.5
0.6
0.7
0.8
0.9
1.0
0
5
10
15
20
Measured Wind Speed (8m)
Scaled Wind Speed (30m)

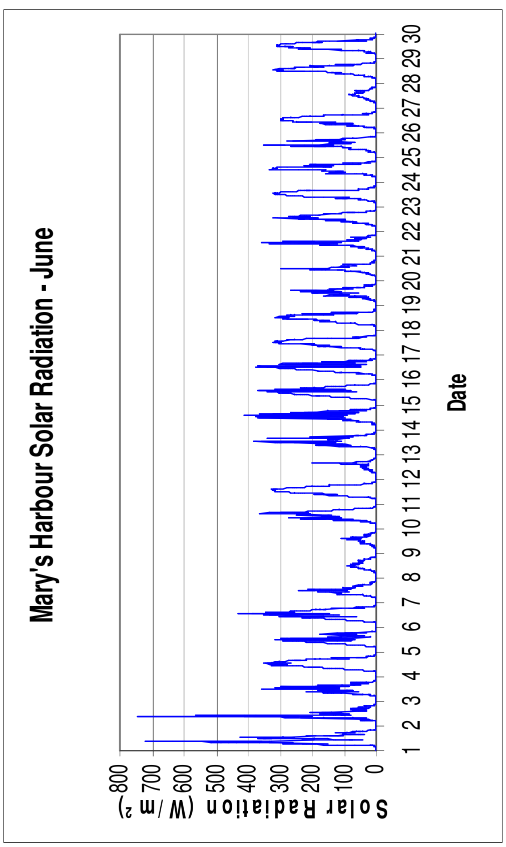

Mary's Harbour Wind Duration Curve - July
Wind Speed (m/s)
Per Unit Time
0.0
0.1
0.2
0.3
0.4
0.5
0.6
0.7
0.8
0.9
1.0
0
5
10
15
20
Measured Wind Speed (8m)
Scaled Wind Speed (30m)

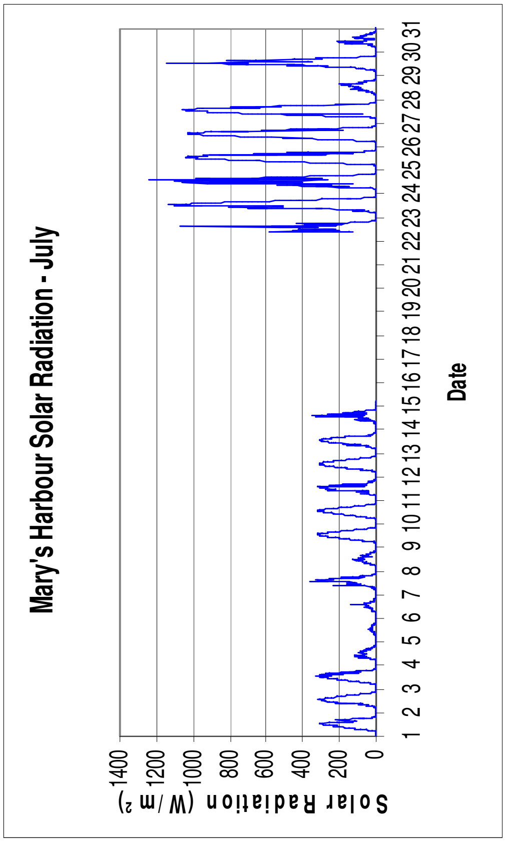

Mary's Harbour Wind Duration Curve - August
Wind Speed (m/s)
Per Unit Time
0.0
0.1
0.2
0.3
0.4
0.5
0.6
0.7
0.8
0.9
1.0
0
5
10
15
20
Measured Wind Speed (8m)
Scaled Wind Speed (30m)

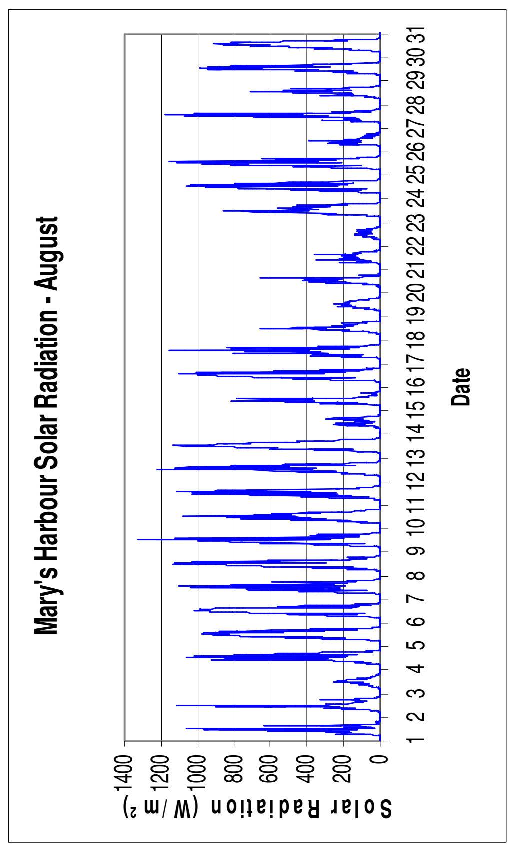

Mary's Harbour Wind Duration Curve - September
Wind Speed (m/s)
Per Unit Time
0.0
0.1
0.2
0.3
0.4
0.5
0.6
0.7
0.8
0.9
1.0
0
5
10
15
20
Measured Wind Speed (8m)
Scaled Wind Speed (30m)

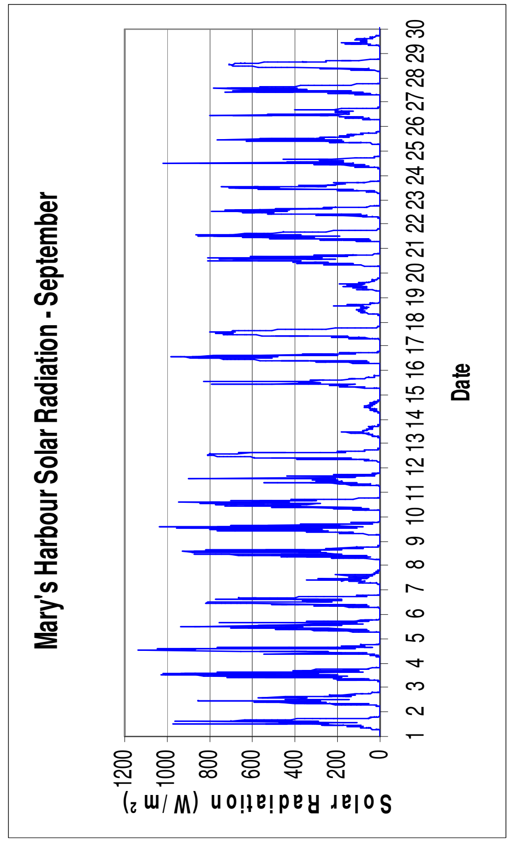

Mary's Harbour Wind Duration Curve - November
Wind Speed (m/s)
25
20
15
10
5
0
0.0
0.1
0.2
0.3
0.4
0.5
0.6
0.7
0.8
0.9
1.0
Per Unit Time
Measured Wind Speed (8m)
Scaled Wind Speed (30m)

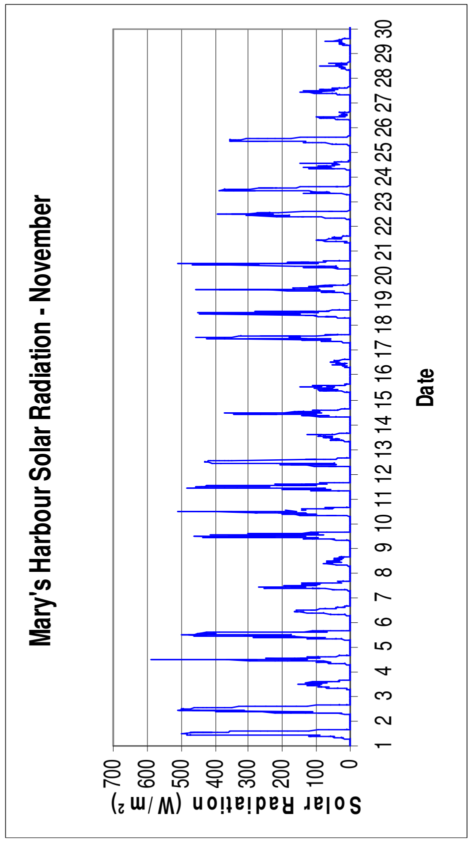

Mary's Harbour Wind Duration Curve - October
Wind Speed (m/s)
30
25
20
15
10
5
0
0.0
0.1
0.2
0.3
0.4
0.5
0.6
0.7
0.8
0.9
1.0
Per Unit Time
Measured Wind Speed (8m)
Scaled Wind Speed (30m)

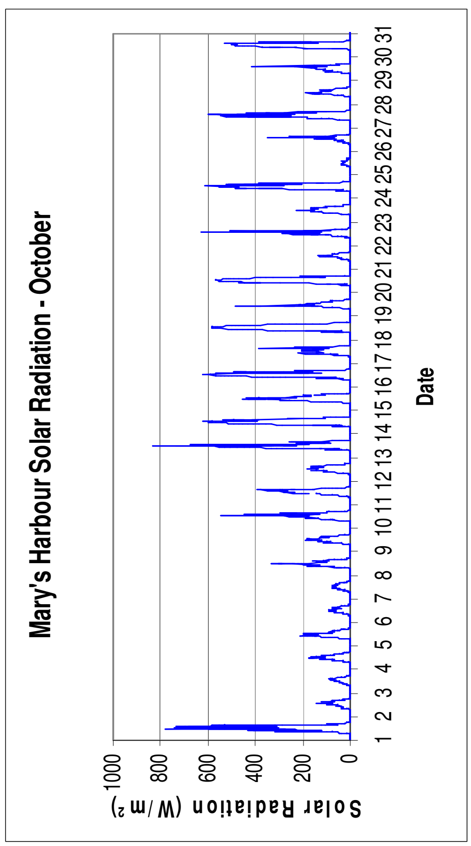

Mary's Harbour Solar Radiation - June
Solar Radiation (W/m²)
800 700 600 500 400 300 200 100 0
1 2 3 4 5 6 7 8 9 10 11 12 13 14 15 16 17 18 19 20 21 22 23 24 25 26 27 28 29 30
Date

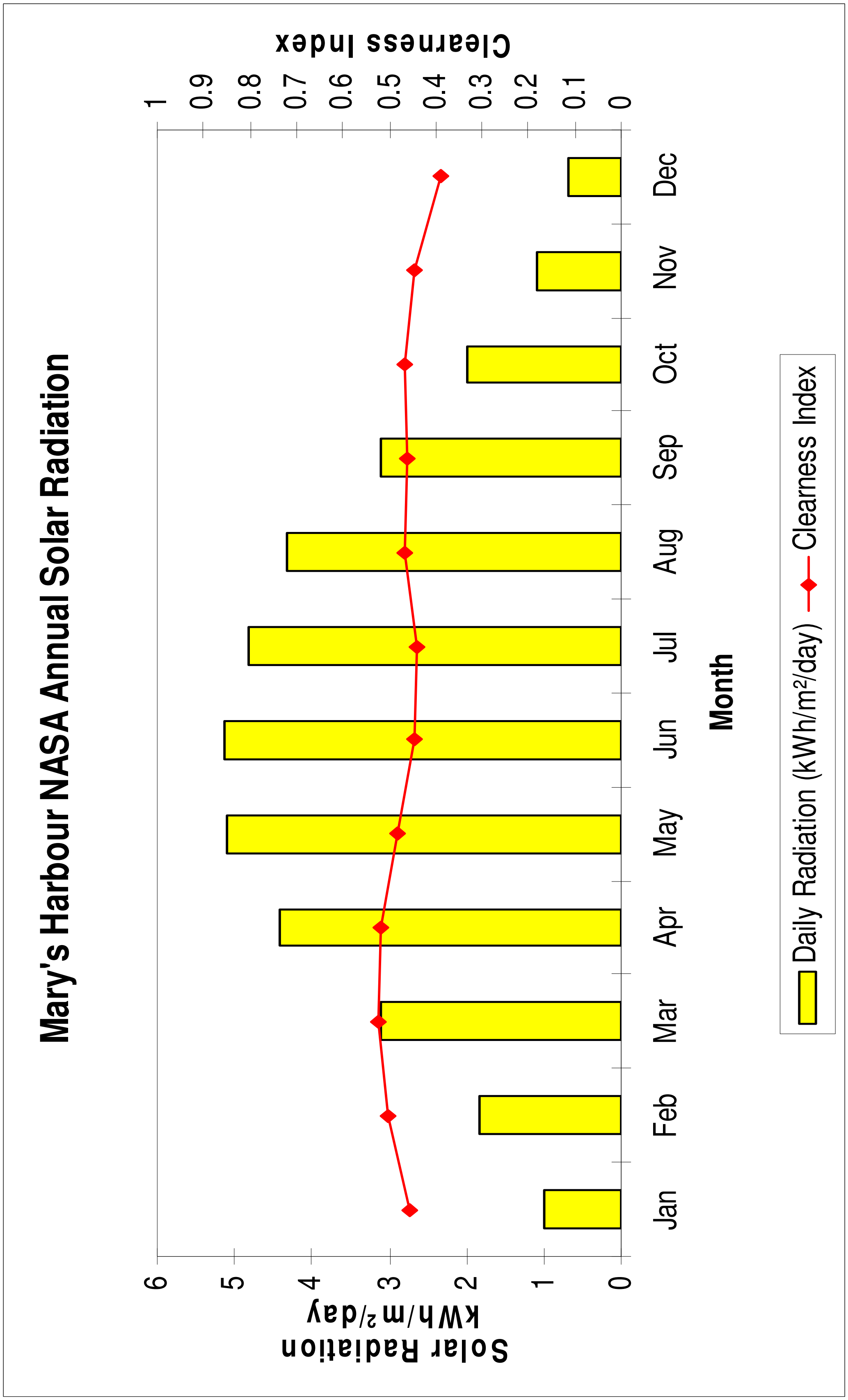

Mary's Harbour Solar Radiation - July
Solar Radiation (W/m²)
1400 1200 1000 800 600 400 200 0
1 2 3 4 5 6 7 8 9 10 11 12 13 14 15 16 17 18 19 20 21 22 23 24 25 26 27 28 29 30 31
Date

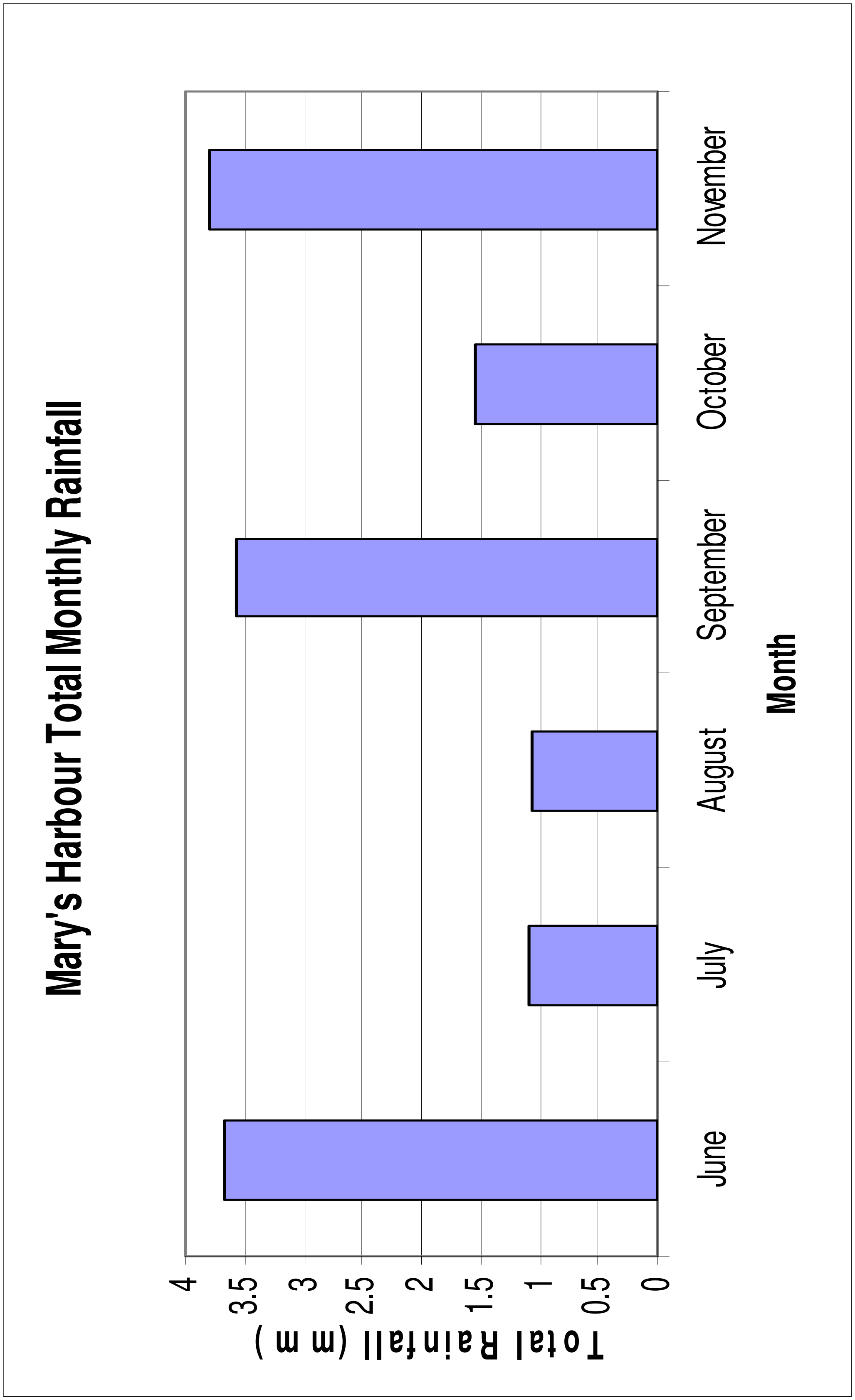

Mary's Harbour Solar Radiation - August
Solar Radiation (W/m²)
1400 1200 1000 800 600 400 200 0
1 2 3 4 5 6 7 8 9 10 11 12 13 14 15 16 17 18 19 20 21 22 23 24 25 26 27 28 29 30 31
Date


Mary's Harbour Solar Radiation - September
Solar Radiation (W/m²)
1200 1000 800 600 400 200 0
1 2 3 4 5 6 7 8 9 10 11 12 13 14 15 16 17 18 19 20 21 22 23 24 25 26 27 28 29 30
Date


Mary's Harbour Solar Radiation - November
Solar Radiation (W/m²)
700
600
500
400
300
200
100
0
1 2 3 4 5 6 7 8 9 10 11 12 13 14 15 16 17 18 19 20 21 22 23 24 25 26 27 28 29 30
Date


Mary's Harbour Solar Radiation - October
Solar Radiation (W/m²)
1000
800
600
400
200
0
1 2 3 4 5 6 7 8 9 10 11 12 13 14 15 16 17 18 19 20 21 22 23 24 25 26 27 28 29 30 31
Date


Mary's Harbour NASA Annual Solar Radiation
Solar Radiation kWh/m²/day
Clearness Index
Month
Jan
Feb
Mar
Apr
May
Jun
Jul
Aug
Sep
Oct
Nov
Dec
0
1
2
3
4
5
6
0.1
0.2
0.3
0.4
0.5
0.6
0.7
0.8
0.9
Daily Radiation (kWh/m²/day)
Clearness Index

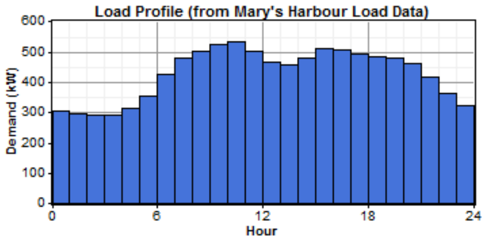

Mary's Harbour Total Monthly Rainfall
Total Rainfall (mm)
0
0.5
1
1.5
2
2.5
3
3.5
4
June
July
August
September
October
November
Month

HOMER Input Summary

File name: MSH.hmr
File version: 2.68 beta
Author:

AC Load: Mary's Harbour Net System Load

Data source:	Mary's Harbour Load Data.txt
Daily noise:	8.32%
Hourly noise:	6.61%
Scaled annual average:	10,367, 10,471, 10,573, 10,666, 10,756 kWh/d
Scaled peak load:	839, 847, 856, 863, 870 kW
Load factor:	0.515



PV

Size (kW)	Capital ($)	Replacement ($)	O&M ($/yr)
50.000	400,000	400,000	10,000
100.000	750,000	750,000	15,000

Sizes to consider:	0, 50, 100 kW
Lifetime:	20 yr
Derating factor:	80%
Tracking system:	No Tracking
Slope:	52.3 deg
Azimuth:	0 deg
Ground reflectance:	20%

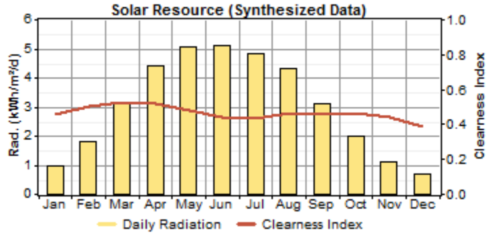
Solar Resource

Latitude: 52 degrees 18 minutes North
Longitude: 55 degrees 50 minutes West
Time zone: GMT -3:30

Data source: Synthetic

Month	Clearness Index	Average Radiation
		(kWh/m^2/day)
Jan	0.454	0.980
Feb	0.505	1.820
Mar	0.525	3.100
Apr	0.518	4.410
May	0.481	5.090
Jun	0.445	5.120
Jul	0.438	4.830
Aug	0.466	4.320
Sep	0.460	3.120
Oct	0.465	1.990
Nov	0.444	1.100
Dec	0.387	0.680

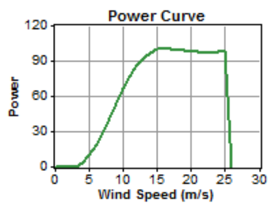
Scaled annual average: 3.04 kWh/m²/d



AC Wind Turbine: Northern Power NW100/21

Quantity	Capital ($)	Replacement ($)	O&M ($/yr)
1	500,000	400,000	10,000

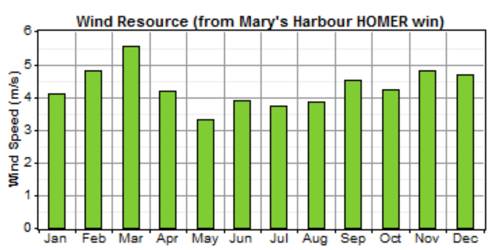
Quantities to consider: 0, 1, 2, 3, 4, 5, 6, 7, 8, 9, 10
Lifetime: 20 yr
Hub height: 37 m



Wind Resource

Data source: Mary's Harbour HOMER wind speeds.txt

Month	Wind Speed (m/s)
Jan	4.11
Feb	4.78
Mar	5.56
Apr	4.18
May	3.30
Jun	3.89
Jul	3.71
Aug	3.83
Sep	4.51
Oct	4.22
Nov	4.80
Dec	4.69



Weibull k: 1.60
Autocorrelation factor: 0.861
Diurnal pattern strength: 0.0797
Hour of peak wind speed: 10
Scaled annual average: 4.29 m/s
Anemometer height: 8 m
Altitude: 8 m

Wind shear profile: Logarithmic
Surface roughness length: 0.01 m

AC Hydro:

Capital cost: $ 3,040,000, 9,354,000, 8,769,000, 4,677,000, 5,495,000, 5,000,000, 6,900,000, 1,700,000, 3,700,000
Replacement cost: $ 0
O&M cost: $ 33,860, 44,070, 40,700, 18,550, 12,290, 7,190, 6,260, 700, 700/yr
Lifetime: 60 yr
Available head: 12, 16, 73, 12, 16, 14, 12, 5, 31 m
Design flow rate: 4,460, 4,360, 880, 2,450, 1,220, 820, 830, 210, 40 L/s
Min. flow ratio: 15, 15, 10, 15, 15, 15, 15, 15, 15%
Max. flow ratio: 100%
Turbine efficiency: 85%
Pipe head loss: 0%

Consider systems without hydro: Yes

Hydro Resource

Data source: Synthetic

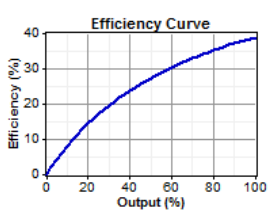
Month	Stream Flow (L/s)
Jan	188
Feb	124
Mar	141
Apr	382
May	394
Jun	382
Jul	394
Aug	394
Sep	382
Oct	394
Nov	382
Dec	318

Residual flow: 0 L/s
Scaled annual average: 321, 411, 384, 175, 117, 68, 60, 7, 7 L/s

AC Generator: 2037

Size (kW)	Capital ($)	Replacement ($)	O&M ($/hr)
600.000	0	600,000	1.850

Sizes to consider: 600 kW
Lifetime: 100,000 hrs
Min. load ratio: 30%
Heat recovery ratio: 0%
Fuel used: #1 Diesel Arctic Grade
Fuel curve intercept: 0.105 L/hr/kW
Fuel curve slope: 0.144 L/hr/kW

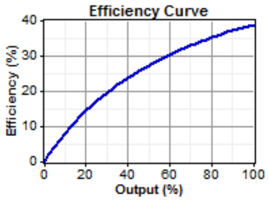


AC Generator: 2038

Size (kW)	Capital ($)	Replacement ($)	O&M ($/hr)

600.000	0	600,000	1.850

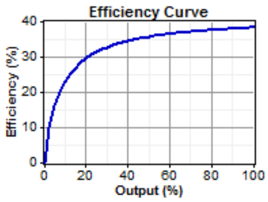
Sizes to consider: 600 kW
Lifetime: 100,000 hrs
Min. load ratio: 30%
Heat recovery ratio: 0%
Fuel used: #1 Diesel Arctic Grade
Fuel curve intercept: 0.105 L/hr/kW
Fuel curve slope: 0.144 L/hr/kW



AC Generator: 2048

Size (kW)	Capital ($)	Replacement ($)	O&M ($/hr)
810.000	0	600,000	2.489

Sizes to consider: 810 kW
Lifetime: 100,000 hrs
Min. load ratio: 30%
Heat recovery ratio: 0%
Fuel used: #1 Diesel Arctic Grade
Fuel curve intercept: 0.0186 L/hr/kW
Fuel curve slope: 0.235 L/hr/kW



Fuel: #1 Diesel Arctic Grade

Price: $ 0.922, 0.921, 0.941, 0.970, 0.970/L
Lower heating value: 45.8 MJ/kg
Density: 809 kg/m3
Carbon content: 88.0%
Sulfur content: 0.0500%

Converter

Size (kW)	Capital ($)	Replacement ($)	O&M ($/yr)
100.000	64,000	64,000	6,400

Sizes to consider: 0, 100 kW
Lifetime: 15 yr
Inverter efficiency: 90%
Inverter can parallel with AC generator: Yes
Rectifier relative capacity: 100%
Rectifier efficiency: 85%

Economics

Annual real interest rate: 8%
Project lifetime: 60 yr
Capacity shortage penalty: $ 0/kWh
System fixed capital cost: $ 0

System fixed O&M cost: $ 0/yr

Generator control

Check load following: Yes
Check cycle charging: No

Allow systems with multiple generators:	Yes
Allow multiple generators to operate simultaneously:	Yes
Allow systems with generator capacity less than peak load:	No

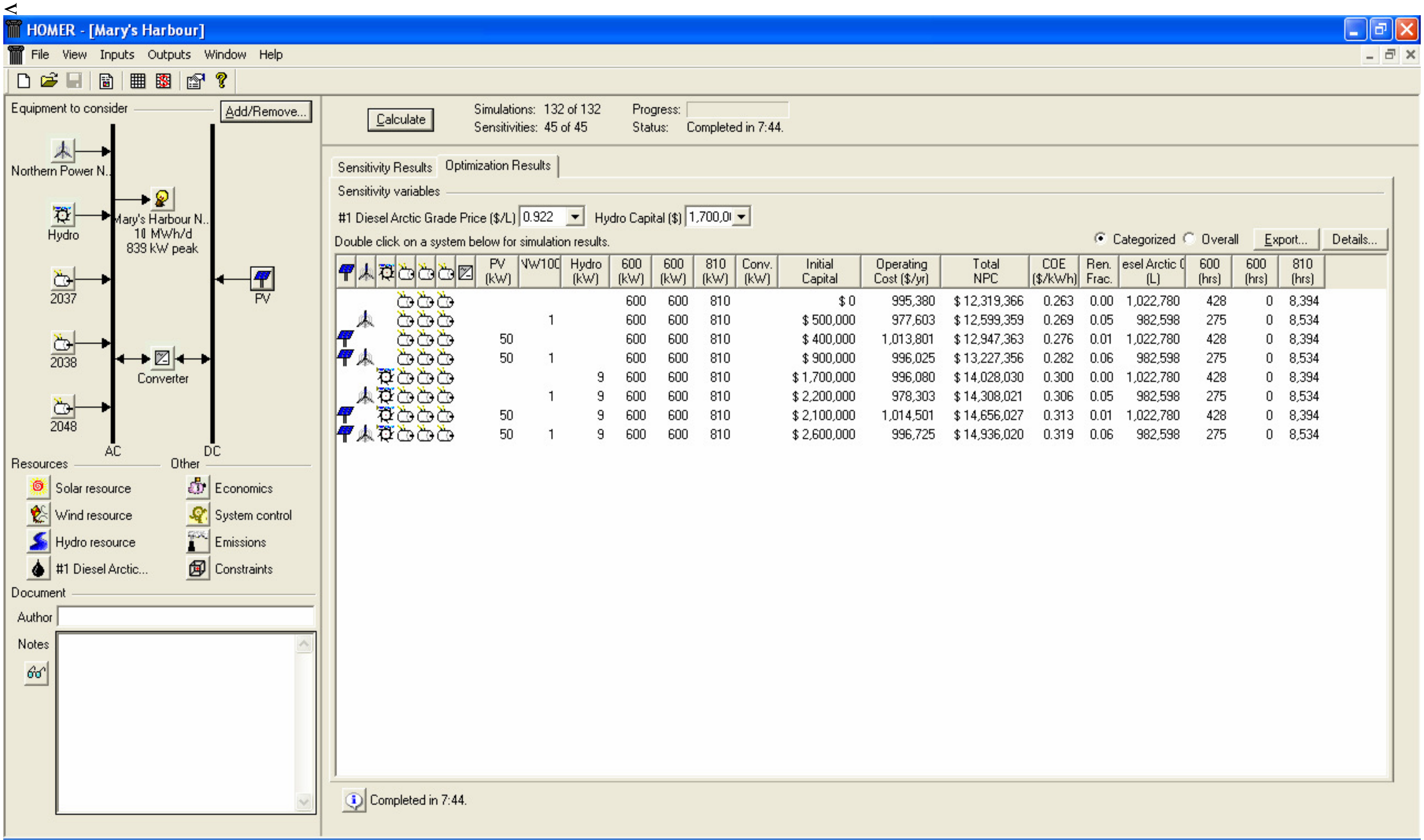
Emissions

Carbon dioxide penalty:	$ 0/t
Carbon monoxide penalty:	$ 0/t
Unburned hydrocarbons penalty:	$ 0/t
Particulate matter penalty:	$ 0/t
Sulfur dioxide penalty:	$ 0/t
Nitrogen oxides penalty:	$ 0/t

Constraints

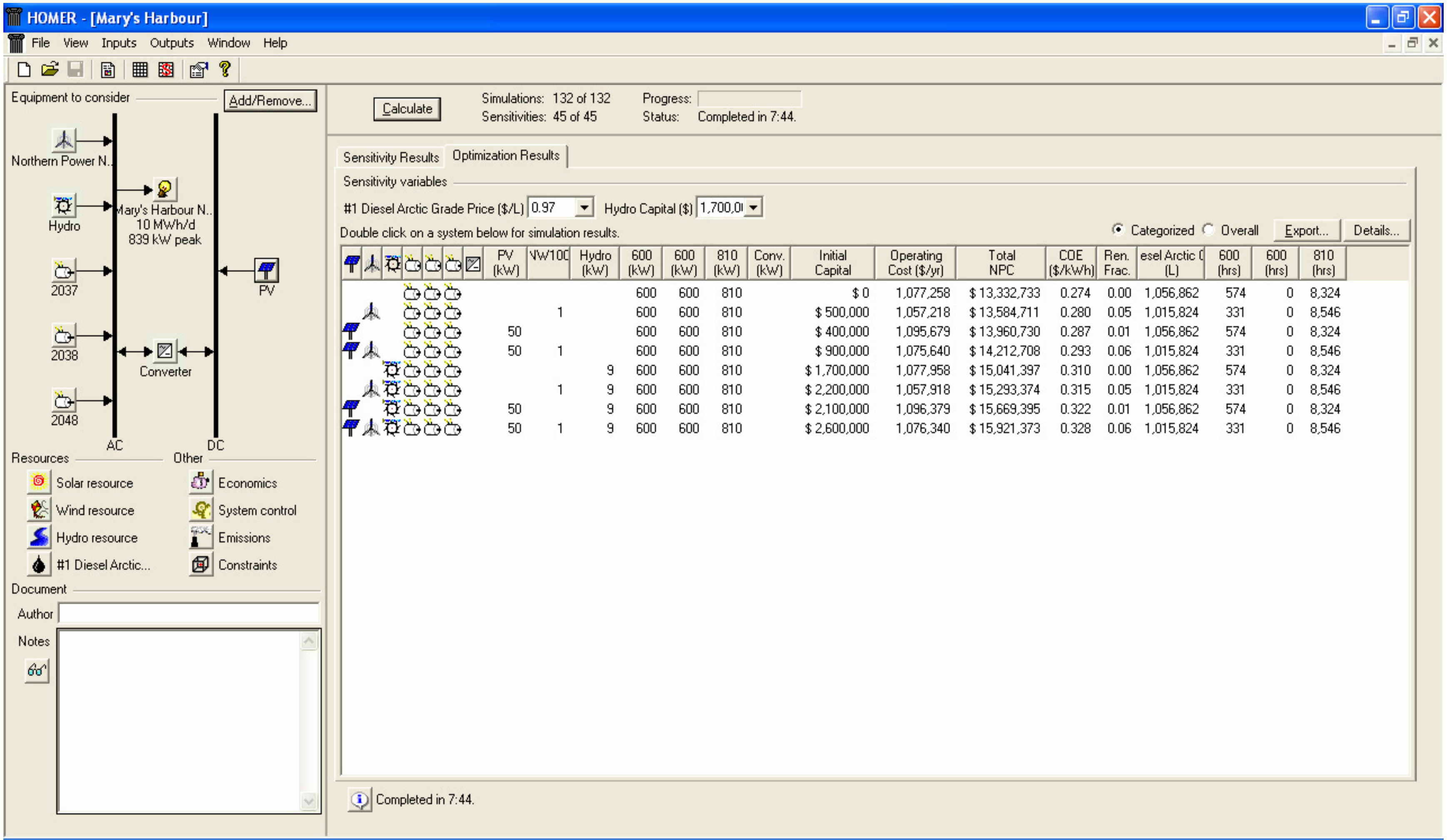
Maximum annual capacity shortage:	0%
Minimum renewable fraction:	0%

Operating reserve as percentage of hourly load:	10%
Operating reserve as percentage of peak load:	0%
Operating reserve as percentage of solar power output:	25%
Operating reserve as percentage of wind power output:	50%



PV (kW)	W100	Hydro (kW)	600 (kW)	600 (kW)	810 (kW)	Conv. (kW)	Initial Capital	Operating Cost ($/yr)	Total NPC	COE ($/kWh)	Ren. Frac.	esel Arctic ((L)	600 (hrs)	600 (hrs)	810 (hrs)
			600	600	810		$ 0	995,380	$ 12,319,366	0.263	0.00	1,022,780	428	0	8,394
	1		600	600	810		$ 500,000	977,603	$ 12,599,359	0.269	0.05	982,598	275	0	8,534
50			600	600	810		$ 400,000	1,013,801	$ 12,947,363	0.276	0.01	1,022,780	428	0	8,394
50	1		600	600	810		$ 900,000	996,025	$ 13,227,356	0.282	0.06	982,598	275	0	8,534
		9	600	600	810		$ 1,700,000	996,080	$ 14,028,030	0.300	0.00	1,022,780	428	0	8,394
	1	9	600	600	810		$ 2,200,000	978,303	$ 14,308,021	0.306	0.05	982,598	275	0	8,534
50		9	600	600	810		$ 2,100,000	1,014,501	$ 14,656,027	0.313	0.01	1,022,780	428	0	8,394
50	1	9	600	600	810		$ 2,600,000	996,725	$ 14,936,020	0.319	0.06	982,598	275	0	8,534

Mary's Harbour HOMER Results – 2011 System



PV (kW)	NW100	Hydro (kW)	600 (kW)	600 (kW)	810 (kW)	Conv. (kW)	Initial Capital	Operating Cost ($/yr)	Total NPC	COE ($/kWh)	Ren. Frac.	esel Arctic ((L)	600 (hrs)	600 (hrs)	810 (hrs)
			600	600	810		$ 0	1,077,258	$ 13,332,733	0.274	0.00	1,056,862	574	0	8,324
	1		600	600	810		$ 500,000	1,057,218	$ 13,584,711	0.280	0.05	1,015,824	331	0	8,546
50			600	600	810		$ 400,000	1,095,679	$ 13,960,730	0.287	0.01	1,056,862	574	0	8,324
50	1		600	600	810		$ 900,000	1,075,640	$ 14,212,708	0.293	0.06	1,015,824	331	0	8,546
		9	600	600	810		$ 1,700,000	1,077,958	$ 15,041,397	0.310	0.00	1,056,862	574	0	8,324
	1	9	600	600	810		$ 2,200,000	1,057,918	$ 15,293,374	0.315	0.05	1,015,824	331	0	8,546
50		9	600	600	810		$ 2,100,000	1,096,379	$ 15,669,395	0.322	0.01	1,056,862	574	0	8,324
50	1	9	600	600	810		$ 2,600,000	1,076,340	$ 15,921,373	0.328	0.06	1,015,824	331	0	8,546

Mary's Harbour HOMER Results – 2015 System

HATCH™

Newfoundland and Labrador Hydro
Coastal Labrador Wind Monitoring Program

Final report- Coastal Labrador Wind Monitoring Program

						R.Hodder
2015-11-26	B	Final	Dany Awad	Ève-Line Brouillard	L. Auger	Dec. 17, 2015 R. Hodder
Date	Rev.	Status	Prepared By	Checked By	Approved By	Approved By
HATCH						Client

Safety • Quality • Sustainability • Innovation

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Appendix J Hybrid system modelling and optimisation report - L'Anse au Loup

DISCLAIMER (rnb Dec 17th)

This report has been prepared by Hatch Ltd ("Hatch") for the sole and exclusive use of Newfoundland and Labrador Hydro (the "Client") for the purpose of assisting the Client to measure and evaluate the wind conditions and determine the preliminary costs and viability of implementing wind power generation in 5 communities in Labrador as part of the Coastal Labrador Wind monitoring Program (the "Project") and shall not be used for any other purpose.

Hatch acknowledges that this report may be provided to third parties provided that all such parties shall rely upon this report at their own risk and shall (by virtue of their receipt of the report) be deemed to have (a) acknowledged that Hatch shall not have any liability to any party other than the Client in respect of the report and (b) waived and released Hatch from any liability in connection with the report.

This report contains opinions, conclusions and recommendations made by Hatch, using its professional judgment and reasonable care. Use of or reliance upon this report by Client is subject to the following conditions:

(a) the report being read in the context of and subject to the terms of the Consultant Services Agreement between Hatch and the Client dated 15 March 2012 (the "Agreement"), including any methodologies, procedures, or assumptions agreed therein;

(b) the estimate is based on several factors over which Hatch has no control including without limitation site conditions, cost and availability of inputs, etc, and Hatch takes no responsibility for the impact that changes to these factors may have on the accuracy or validity or this estimate; and

(c) the estimate is based on information made available to Hatch by the Client or by certain third parties including information respecting to environment and community constraints, estimates for CapEx and OpEx, and unless stated otherwise in the Agreement, Hatch has not verified the accuracy of such information, makes no representation regarding the accuracy of such information and hereby disclaims any liability in connection therewith.

(d) The report, including the estimates contained herein, being read as a whole, with sections or parts hereof read or relied upon in context; and

The conditions of the site may change over time (or may have already changed) due to natural forces or human intervention, and Hatch takes no responsibility for the impact that such changes may have on the accuracy or validity or the observations, conclusions and recommendations set out in this report

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Confidential: may be shared within client's organisation

Executive Summary

Newfoundland and Labrador Hydro (NLH) commissioned Hatch to perform Wind Resource Assessments (WRA) and related analyses for five communities in coastal Labrador: Nain, Hopedale, Makkovik, Cartwright and L'Anse au Loup.

The objective of the Coastal Labrador Wind Monitoring Program was to identify potentially windy areas that also possess other desirable qualities of a wind energy development site.

This final report documents the approach taken and the results of the Coastal Labrador Wind Monitoring Program completed at the five sites from January 2011 to August 2015.

Preliminary site assessment was completed to identify potential site locations in all five communities. This phase included preliminary environmental screening, site visits, permitting and the preliminary evaluation of factors such as wind and constructability.

Following the identification of a specific site in each community, meteorological towers were acquired and installed from July to November 2013. Meteorological data was collected from all five communities for 18 months and towers were dismantled in July 2015.

A wind resource assessment report was completed for each community and are presented in Appendices A to E of this report. The main elements of the WRA reports conclude that the wind monitoring campaign was successfully completed and data recovery rates exceeded industry standards. Energy yield was calculated using the meteorological data collected and was based on a preliminary turbine selection. The results of these calculations are presented in the table below.

Table 1-1 : Energy Yield per Community

Project	Layout # - Turbine Model (Number of WTG)	Wind Farm Capacity (KW)	Net Energy Production (MWh/year)	Wake Losses (%)	Additional Losses (%)	Net Capacity Factor (%)
Nain	Layout 1 - EWT900 (2)	1800	6,150	0.5	14.6	39.0
	Layout 2 - NPS100 (12)	1200	4,058	2.5	14.3	38.6
Hopedale	Layout 1 - EWT900 (1)	900	3,398	0.0	14.0	43.1
	Layout 2 - NPS100 (8)	800	2,765	2.2	13.8	39.4
Makkovik	Layout 1 - EWT900 (1)	900	3,102	0.0	14.1	39.3
	Layout 2 - NPS100 (5)	500	1,728	1.1	13.6	39.4
L'Anse au Loup	Layout 1 - EWT900 (4)	3600	11,651	1.2	13.7	36.9
Cartwright	Layout 1 - EWT900 (1)	900	2,898	0.0	14.2	36.7
	Layout 2 - NPS100 (5)	500	1,559	4.0	14.0	35.6

The final phase of the wind monitoring program was to conduct a preliminary evaluation of the feasibility to integrate wind with each of the community's diesel-fuelled electrical generators and to establish the potential economic viability of the projects. This phase was completed using a software known as Homer, using input from NLH and the energy yields estimated in the WRA phase.

It is important to note that a number of additional studies and estimates will require to be completed as part of the detailed design phase. The initial analysis and modelling completed as part of this preliminary evaluation indicates that the implementation of wind in all communities, except L'Anse au Loup, could potentially reduce diesel consumption and may lower the overall costs of energy in four of the communities. A summary of the results of the hybrid modelling and optimisation for the five communities, as well as an overall ranking of the communities, are presented in Appendices F to J.

The installation of WTGs on the grid at each of the communities will require further electrical and mechanical studies, which are not part of the current scope of work and should be performed at a later stage to fully assess the project viability. The results of these studies will determine whether additional control and communication equipment needs to be added to the system. It should be noted that since it is not currently known if any additional equipment will be required, no cost was included for such components in any of the simulations at this stage. The energy costs presented in this report and relevant annexes include no allocation for additional control and communication equipment.

As noted in the reports *Hybrid System Modelling and Optimisation*, provided in Appendices F to J, the cost of energy does not include all applicable costs. As such, this preliminary evaluation of energy costs indicates that the projects may be viable (or not) and warrants further study. Additional costs not reflected here include mechanical and electrical stability studies, system integration costs, control and communications system costs, as well as detailed logistic studies, plant detailed design and optimization.

In conclusion, the Coastal Labrador Wind Monitoring Program identified that the implementation of wind turbines in four of the five communities has potential and could possibly result in reductions in diesel consumption if integrated correctly. The overall business case for the investment remains to be validated as additional studies and community consultation will be required prior to completion of the final design.

The Coastal Labrador Wind Monitoring Program was a prefeasibility study and additional studies and validations will be required prior to initiating the detailed design phase and implementation. Many studies and actions will be iterative in nature and will require validation in the planning and implementation phase.

1. Introduction

As a follow up to the Coastal Labrador Alternative Energy Study commissioned by the Government of Newfoundland and Labrador in 2008, Newfoundland and Labrador Hydro (NLH) commissioned Hatch to perform Wind Resource Assessments (WRA) and related analyses for five communities in coastal Labrador: Nain, Hopedale, Makkovik, Cartwright and L'Anse au Loup. The main objective of the program was to identify potentially windy areas that also possess other desirable qualities of a wind energy development site.

The Coastal Labrador Wind Monitoring Program was divided in five phases as follows:

a. Phase 1: Site Selection and Environmental Screening,

b. Phase 2: Meteorological Tower Design Validation and Installation,

c. Phase 3: Meteorological Data Collection for 18 months,

d. Phase 4: Preparation of Wind Resource Assessment Report for each community, and

e. Phase 5: Preparation of Hybrid System Modelling and Optimisation Reports for each community.

1.1 Report Organization

To simplify the presentation of results in this Final Report, detailed Wind Resource Assessment (WRA) and Hybrid System Modelling and Optimisation Reports were completed for each of the five communities and are included as individual Appendix to this report. This report provides a summary of the methodology and the analysis and findings that are detailed in the appendixes. This report has been organized as follows:

- Section 1: Introduction.
- Section 2: Summary of Methodology and Findings during Site Selection Phase.
- Section 3: Methodology and Findings of Meteorological Tower Design and Installation Phase.
- Section 4: Summary of Findings - Data Collection Phase.
- Section 5: Summary of Findings - Wind Resource Assessment Phase.
- Section 6: Summary of Findings - Hybrid System Modelling and Optimisation Phase.
- Section 7: Conclusions and Recommendations.
- Appendices A-E: Wind Resource Assessment Reports for all 5 communities.
- Appendices F-J: Hybrid System Modelling and Optimisation Reports for all 5 communities.

2. Phase 1: Site Selection

This report does not contain all of the information previously included in the site selection report which was provided to NLH in July 2013. Rather, the following is a summary of the methodology and findings of the site selection phase of the project.

The methodology of the site selection phase included the following main steps:

- Preliminary desktop screening of multiple site options including preliminary environmental screening.
- Site visits by members of the project team to validate desktop study results.
- Permitting considerations (e.g., aviation safety, land use).
- Discussion of options within the project team and final approval by the Client.

Site selection for the purpose of installing Meteorological masts and for guiding subsequent wind power development was based on the following main criteria:

- Wind resource & energy estimates.
- Icing potential.
- Constructability (cost of road and grid extension).
- Environmental constraints.
- Land use (including regulatory issues).
- Potential interference with air traffic and communications.

The site selection process was completed based on the following steps:

Step 1: At each community, a number of candidate sites were identified based on expert opinion, considering the objectives of the project and the criteria shown above.

Step 2: Each of the candidate sites were evaluated against the selection criteria.

Step 3: A comparison matrix was used for arriving at a combined ranking for all qualitative criteria.

The preliminary desktop screening was performed by Sikimiut Environmental Management Ltd (Sikimiut) and included a review of the potential environmental restrictions that could be found within each community. It is important to note that the environment screening was completed in 2011 and was preliminary in nature. As such, additional and/or new environmental and community restrictions may exist and this will need to be validated prior to the detailed design phase.

Based on the desktop screening results, site visits were conducted from June 11-15, 2012. The visits served to validate the findings of the desktop screening analysis and to provide

NLH and Hatch staff with a first-hand view of the key sites. The team reviewed the site visit results and discussed site options to determine which measurement sites were to be considered priority. These were further adjusted based on the results of aeronautical clearance applications to NAV Canada and Transport Canada and land use permitting considerations. The possibility of co-locating instruments on existing Bell Aliant towers was considered for some locations but ultimately rejected. The resulting final tower locations were approved and are presented in Section 3 of this report and additional details are included in the WRA reports found in Appendix A to E.

The land use permitting process for the meteorological masts differs by jurisdiction and community. For the 3 northern communities (Nain, Hopedale and Makkovik) which are located in Nunatsiavut territory, a general Research Authorization was received from the Nunatsiavut Government as well as specific permits from the individual Inuit Community Governments (ICGs).

For L'Anse au Loup and Cartwright, Municipal and Crown Land approvals were received from the municipal and provincial governments, respectively.

Maps showing all wind project development locations are included in Appendices A – E for the individual communities.

3. Phase 2: Meteorological Tower Design Validation and Installation

3.1 Meteorological Tower Design

Wind varies strongly with geographical locations and is strongly influenced by elevation, topography, surrounding vegetation, large nearby water bodies and local obstacles. Coastal Labrador is known for the relative high incidence of icing in the fall, winter and spring periods. High icing environments present structural and operational challenges for the meteorological towers required for wind resource assessment which needed to be considered in the meteorological tower design process.

As a first step in understanding the local wind resource, relevant sources of wind data and icing information were obtained to determine the appropriate Ice and wind load level requirements for each of the community and investigate off the shelf tubular or lattice towers that could meet these requirements.

Based on this analysis and investigation, a 36 meter lattice tower from Advanced Masts Systems Inc. was selected and a picture of the tower from Nain is provided below.

Figure 3-1 : MetMast at Nain

In order to record wind data measurements throughout the 12 months (including winter months), instrumentation was selected to enable good data recovery rates in icing conditions. Details on specific instrumentation used on all 5 meteorological towers can be found in the table below.

Table 3-1: Met Tower Instrumentation

ID	Height (m)	Type	Calibrated / Heated	Heated	Primary (P) or Redundant (R)
N/A	N/A	NRG Symphonie PLUS3	N/A	N/A	N/A
A1	35.0	NRG #40C	Yes	No	P
A2	35.0	NRG Icefree III	Yes	Yes	R
A3	26.0	NRG #40C	Yes	No	P
A5	26.0	RMYoung 5103-AP	Yes	No	R
A4	17.0	NRG #40C	Yes	No	P
V1	33.0	NRG Icefree III	No	Yes	P
V2	26.0	RMYoung 5103-AP	No	No	R
V3	15.0	NRG #200P	No	No	R
T	34.0	NRG #110S	No	No	P

3.2 Meteorological Tower Installations

After acquiring the five meteorological towers and all associated equipment and instruments, all the material was shipped to Goose Bay and then redistributed to the respective communities in August and September 2013.

Hatch worked with Sikimiut staff to coordinate logistics and local support.

All five towers were installed and commissioned from 1 October 2013 to 5 November 2013. Copies of the tower installation reports were completed and transferred to NLH for reference.

Other information relevant to the tower installations and specifications on instrumentation can be found in the respective WRA reports in Appendices A to E.

4. Phase 3: Meteorological Data Collection for 18 months

The wind measurement campaigns covered a period of 18 months at all 5 communities. The data were collected periodically from the meteorological masts and sent to the Hatch computer network via a satellite communication system. The quality of the data was analysed and data points that were deemed erroneous or unreliable were replaced by redundant data when available, or removed from the data set.

To comply with the best practices in WRA, a 12-month period was selected for every site to better assess the annual energy estimate of the wind project and to avoid seasonal variations in wind.

The following table provides the dates of mast installation, the periods of relevant data collection and the data recovery rates for the main anemometer used in the wind resource assessment analysis.

Table 4-1: Met Tower Installation, Data Collection Period and Recovery Rate

Project	Met mast ID	Installation Date	Relevant Data Collection		Recovery Rate (%)
			From	To	
Nain	2601	October 30, 2013	December 1, 2013	November 30, 2014	97.8
Hopedale	2602	October 27, 2013	December 1, 2013	November 30, 2014	98.6
Makkovik	2603	October 25, 2013	November 1, 2013	October 31, 2014	93.8
L'Anse au Loup	2604	October 5, 2013	November 1, 2013	October 31, 2014	99.0
Cartwright	2605	November 5, 2013	December 1, 2013	November 30, 2014	99.3

The data recovery rates at all 5 sites exceeded industry standards for wind monitoring measurements. The high data recovery rate ensures that the set of data available is representative of the wind resource over the measurement period.

The wind monitoring period as mandated in the RFP covered a period of 18 months in order to ensure that a good recovery rate was obtained and that two winters worth of data were available. The wind monitoring period was considered a success after 18 months of data acquisition as the recovery rates were above standard for all communities. There was an option as part of RFP to extend the monitoring period by an additional 6 months but due to success of the monitoring in first 18 months, this option was not recommended nor exercised.

5. Phase 4: Wind Resource Assessment Reports

5.1 Wind Characteristics

This section provides a summary of the WRA, including elements that are presented in detail in the respective WRA reports in Appendices A to E. The following table provides the main characteristics of the wind regime as it was measured by the meteorological masts installed on the projects' sites.

Table 5-1: Wind Regime Characteristics

Project	Met Mast ID	Measurement Height (m)	Avg Wind Speed (m/s)	Wind Shear	Turbulence Intensity (%)	Annual Average Air Density (kg/m^3)	Icing (%)
Nain	2601	35.0	6.5	0.11	12.6	1.31	5.0
Hopedale	2602	35.0	7.2	0.13	13.6	1.31	5.4
Makkovik	2603	35.0	7.7	0.12	12.0	1.31	1.7
L'Anse au Loup	2604	35.0	7.7	0.19	13.1	1.27	6.8
Cartwright	2605	35.0	6.5	0.11	14.4	1.30	3.1

The wind speeds measured on all five sites range from 6.5 m/s to 7.7 m/s at 35m height. The wind shear exponents were calculated based on the data collected and are consistent with the land cover and topography at the meteorological mast locations. The wind turbulence intensities observed at all sites are moderate. The air density was calculated at each mast according to its elevation and local temperature measurements. The amount of icing estimates was calculated based on the average of icing events detected on the mast during the measurement campaign.

A detailed description of the methodology and the wind characteristics summarized in the table above can be found in Section 3 of the WRA reports provided in Appendices A to E.

5.2 Long Term Extrapolation and Wind Flow Modelling

To forecast the energy production of a wind power plant, wind data that represent the historical wind conditions at the site were required. The WRA analysis were conducted using one full year of data, which is not sufficient to capture the year-to-year variability of the wind. Consequently, and based on industry best practice, it was necessary to translate the measured short-term data into long-term data. This was done through a correlation/adjustment process that makes reference to a meteorological station where historical data is available.

Since the top anemometers of the meteorological masts were mounted at a lower height than the expected hub height of the wind turbines, the long-term data were also extrapolated from the anemometer height to the wind turbines' expected hub heights.

The results of the long term adjustments are presented in the following table.

Table 5-2: Long Term Adjustment

Project	Met Mast ID	Reference Station Name (ID) [Available Data period]	Correlation - Coefficient of Determination R2	Met Mast Short-term Wind Speed (m/s)	Adjustment Factor (%)	Met Mast Long-term Wind Speed (m/s)	Met Mast Long-term Wind Speed at 37m/40m hub heights (m/s)
Nain	2601	Nain (8502799) [2006-2014]	0.84	6.5	0.35	6.5	6.7 / 6.7
Hopedale	2602	Hopedale AUT (8502400) [2005-2014]	0.73	7.2	-1.4	7.1	7.2 / 7.3
Makkovik	2603	Hopedale AUT (8502400) [2005-2014]	0.69	7.7	-1.9	7.6	7.6 / 7.8
L'Anse au Loup	2604	Lourdes De Blanc Sablon A (7040813) [2000-2014]	0.74	7.7	4.5	8.0	8.1 / 8.2
Cartwright	2605	Cartwright (8501100) [2007-2014]	0.69	6.5	6.4	7.0	7.3 / 7.3

Meteorological masts provide a local estimate of the wind resource. Therefore, it was necessary to build a wind flow map based on these measurements to extend the wind resource assessment to the whole project area. The preparation of wind flows for the projects was completed using the WASP software and this provided wind flow maps for all five project areas which were used to optimise the size and layout and energy of the proposed wind projects. The wind flow and energy production are calculated with specialised software that require, apart from the Meteorological masts long-term data, background maps that contain the information on topography, elevation, roughness lengths and potential obstacles. This is also used in conjunction with the wind turbine characteristics. The wind flow maps can be found in the respective WRA reports in Appendices A to E.

5.3 Preliminary Turbine Selection

A preliminary turbine selection analysis was completed based on the following criteria:

- Site's wind speed and turbulence class (IEC class II).
- Extreme wind and weather conditions (operation down to -40C). The coldest 10-minute temperature recording measured during the data collection period ranged from was -30°C in Cartwright to -33.1°C in Hopedale.

- Turbine capacity ranges from 100 KW to 1,000 KW to meet the community load.
- Wind turbine's dimensions and weight versus crane capacity and accessibility.

This preliminary analysis concluded that two turbine models would be suitable for the Coastal Labrador projects: Emergya Wind Technologies 500kW / 900kW (EWT500 / EWT900) and Northern Power 100kW Arctic (NPS100). These models have proven technology in cold and icy environments and are suitable for wind-diesel generation in remote community. Hatch has discussed existing operations of these two turbine models in Alaska which also faces difficult winter conditions. Additional turbine selection analysis will need to be completed prior to initiating the detailed design phase of the respective projects.

The next step required the evaluation of the number of wind turbines that would be optimal based on existing load at each community. The following table shows the results of the WindFarmer optimization which was calculated to establish the optimal number of turbines to meet the community load.

Table 5-3: Evaluation of Number and Model of Turbines

Project	Community Load (kW)	Turbine Model	Optimal Number Of Wind Turbine Required	Ranking
Nain	1200	EWT900	2	1
		NPS100	12	2
Hopedale	750	EWT900	1	1
		NPS100	8	2
Makkovik	500	EWT900	1	1
		NPS100	5	2
L'Anse au Loup	3000	EWT900	4	1
		EWT500+	6	2
Cartwright	500	EWT900	1	1
		NPS100	5	2

* Based on the gross energy output at 30 cents/KWh and the turbine purchase cost only.

+ From a financial point of view, the EWT500 was discarded due to purchased cost similarity and BOP cost. See the WRA reports for more details.

Even though a more detailed turbine selection exercise will be required at a later phase of the project, the NPS 100 and EWT500/900 were considered suitable candidate turbines in order to complete the preliminary energy estimates for the potential wind projects.

5.4 Energy Estimates and Losses

Wind farm layout optimisations were completed using the Windfarmer software, which is one of the leading softwares in the wind industry. The energy production for each wind turbine was calculated using the wind turbines' power curves and thrust curves provided by the turbine manufacturers.

The main results of the energy production modeling are presented below. Additional losses include blade soiling, icing, collection network losses, auxiliary power consumption, wind turbines availability, high wind hysteresis, low temperature shutdown, collection network outage and grid availability.

Table 5-4: Energy Production Results

Project	Layout # - Turbine Model (Number of WTG)	Wind Farm Capacity (KW)	Net Capacity Factor (%)	Wake Losses (%)	Additional Losses (%)	Net Energy Production (MWh/year)	Amount excess energy (MWh/y)
Nain	Layout 1 - EWT900 (2)	1800	39.0	0.5	14.6	6,150	1,380
	Layout 2 - NPS100 (12)	1200	38.6	2.5	14.3	4,058	336
Hopedale	Layout 1 - EWT900 (1)	900	43.1	0.0	14.0	3,398	663
	Layout 2 - NPS100 (8)	800	39.4	2.2	13.8	2,765	366
Makkovik	Layout 1 - EWT900 (1)	900	39.3	0.0	14.1	3,102	1,094
	Layout 2 - NPS100 (5)	500	39.4	1.1	13.6	1,728	166
L'Anse au Loup	Layout 1 - EWT900 (4)	3600	36.9	1.2	13.7	11,651	998
Cartwright	Layout 1 - EWT900 (1)	900	36.7	0.0	14.2	2,898	869
	Layout 2 - NPS100 (5)	500	35.6	4.0	14.0	1,559	103

It is also important to note that not all energy produced by potential wind turbine would be used by the existing system as identified in Table 5-4 above.

The layouts are still considered preliminary and additional validation will be required. Land restrictions, communication corridors, noise and visual impacts, and other site-specific matters such as community acceptance, soil and constructability will need to be evaluated in later phases of the program before the site layout can be considered final.

6. Phase 5: Hybrid System Modelling and Optimisation for Each Community

The main objectives of this part of the mandate were to provide the potential wind turbine capacity that can be integrated to the current electrical supply system of the 5 communities. This included the preliminary evaluation of the potential wind penetration and the associated cost breakdown for development, construction and operations (CapEx and OpEx).

6.1 Existing Electrical Supply Systems

The power grid operated by NLH at four of these five communities currently relies exclusively on diesel generators. The fifth community, L'Anse au Loup, is interconnected to the Hydro-Quebec (HQ) grid, which currently provides over 90% of the electricity being used. The remaining power is supplied by diesel generators.

NLH provided information on the current isolated-grid systems such as the quantity of diesel genset units, the capacity of the gensets, the brand, the fuel consumption, the control logic of operation, the costs of replacement and O&M costs for each unit of each community. The following table summarize the current electrical supply systems. (More information is available in Section 2 of the reports *Hybrid System Modelling and Optimisation*, provided in Appendices F to J.)

Table 6-1: Electrical Supply System in each Community

Project	Quantity of Diesel Genset Unit	Total Capacity of Diesel Gensets (kW)	Maximum Grid Intertia HQ (MW)
Nain	4	3,755	-
Hopedale	4	2,514	-
Makkovik	3	1,550	-
L'Anse au Loup	6	7,150	4
Cartwright	4	2,220	-

NLH also provided time series of the electrical production, historical load values, load growth forecast and fuel costs forecast for the communities. Table 6-2 below gives NLH's anticipated growth of total yearly energy requirements by community for the years 2015 to 2024.

Table 6-2: Forecasted Annual Energy Requirements in MWh

Project	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
Nain	9,019	9,228	9,418	9,608	9,799	9,995	10,195	10,398	10,606	10,819
Hopedale	5,334	5,420	5,599	5,681	5,849	6,024	6,205	6,391	6,551	6,714
Makkovik	4,175	4,214	4,252	4,292	4,330	4,369	4,408	4,448	4,488	4,528
L'Anse au Loup	26,919	27,443	26,687	26,876	27,051	27,211	27,352	27,485	27,609	27,718
Cartwright	4,500	4,536	4,580	4,617	4,661	4,702	4,743	4,784	4,825	4,866

The forecasted load growth and fuel price increase were also considered in the evaluation of the various system configurations as these are important factors over the life of the project. Detailed information on forecasted loads and fuel prices are given in Section 2.4 of the reports *Hybrid System Modelling and Optimisation*, in Appendices F to J.

6.2 Methodology and Assumptions

The electrical systems and integration of the wind turbines were modelled and simulated using the software HOMER (Hybrid Optimization of Multiple Electric Renewables). HOMER can investigate multiple configurations and produce insight as to how to minimize the Levelized Cost of Energy (LCOE) or the system's fuel consumption.

The following information and assumptions were used in the model during the optimization process and in the simulation phase:

- The daily load profile was derived from time series and historical values provided by NLH
- The current systems of energy production were defined in HOMER based on information provided by NLH
- Fuel costs and load growths were based on information provided by NLH
- An inflation rate of 2.21% and average NLH long term marginal cost of debt (rounded) of 6.48% were used, according to historical values specified by NLH
- Construction costs have been defined based on information from manufacturers and historical values from past projects
- The long term wind resource calculated in the wind resource assessment campaign was integrated in HOMER and the energy production predicted by the software WindFarmer for each turbine model was used as a target to adjust some parameters in HOMER
- Two wind turbine models were considered and defined in HOMER : the NPS100 and the EWT900 (the following table shows a comparison between the two models with "X" indicating superiority in each category)

- The sizing and optimisation of the proposed wind projects' integration was determined through an iterative process of HOMER simulations in order to minimize the cost of energy.

Table 6-3: Turbine Model Features

Category	NPS100	EWT900
Track Record	X	X
Turbine Cost		X
Energy Production		X
Control Capabilities		X
Avoided Emissions		X
O&M		X
Logistics	X	

Of note is the fact that the electrical systems integrating wind turbines were modelled by considering a small spinning reserve. As mentioned in the Help of HOMER, spinning reserve "is surplus operating capacity that can instantly respond to a sudden increase in the electrical load or a sudden decrease in the renewable power output". It is possible that more spinning reserve would be required to ensure electrical stability to the hybrid systems. To be able to design the system with the appropriate spinning reserve (enough for stability while minimising expenses), more detailed information would be needed, as the load variations on short period of time, and the time required for generators to be powered and be functional. Increase the spinning reserve would certainly reduce the profitability of the systems, since more diesel would be consumed.

The design methodology is described in more details in Section 3 of the reports *Hybrid System Modelling and Optimisation*, Appendix F to J.

6.3 Modelling Results

The optimal electrical supply system for each community was designed to minimize the cost of energy. The table below shows a summary of the results. The systems with no wind turbine represent the base case. Their costs of energy are provided as a reference for comparison to the costs of the optimal systems retained.

Table 6-4: Cost of Energy and Potential Fuel Savings per Community

Project	No WTG Cost of Energy ($/kWh)	Optimal System Design	Opt. System Cost of Energy ($/kWh)	Fuel Saved vs Base Case	Yearly Fuel Savings
Nain	0.321	2 x EWT900	0.263	43.2%	$1,461,339
Hopedale	0.327	1 x EWT900	0.262	41.0%	$854,928
Makkovik	0.325	1 x EWT900	0.279	42.6%	$660,449
L'Anse au Loup	0.130	No WTG	0.130	-	-
Cartwright	0.323	1 x EWT900	0.279	40.3%	$610,325

As noted in Sections 4.2 and 4.3 of the reports *Hybrid System Modelling and Optimisation*, provided in Appendices F to J, the cost of energy does not include all applicable costs and the costs included are preliminary in nature. As such, this preliminary evaluation of energy costs indicates that the projects are viable (or not) and warrants further study. Additional costs not reflected here include mechanical and electrical stability studies, system integration costs, control and communications system costs, as well as detailed logistic studies, plant detailed design and optimization.

The table below shows a summary of the project estimated preliminary costs that were considered for the optimal system retained for each community. It should be noted that these costs were evaluated based on each projects as separate projects and should more than one project be done concurrently, economies of scale would be possible especially for turbine and construction costs. The construction costs presented in table 6-5 are also preliminary in that no firm price proposals were obtained from third parties and additional costs will be defined as part of the detailed design phase when firm quotes will need to be sought from potential contractors.

Table 6-5: Summary of Construction Costs

	Nain	Hopedale	Makkovik	L'Anse au Loup	Cartwright
Number of units	**2 x EWT900**	**1 x EWT900**	**1 x EWT900**	**No WTG**	**1 x EWT900**
Development costs	$375,000	$375,000	$375,000	N/A	$375,000
Turbine costs	$4,750,000	$2,375,000	$2,375,000	N/A	$2,375,000
Construction costs	$3,291,300	$1,605,900	$1,372,700	N/A	$1,343,550
Project management	$841,630	$435,590	$412,270	N/A	$409,355
Contingency	$688,293	$360,399	$334,747	N/A	$331,541
Total project CapEx:	**$9,946,223**	**$5,151,889**	**$4,869,717**	**N/A**	**$4,834,446**
CapEx / installed MW:	$5,525,679	$5,724,321	$5,410,797	N/A	$5,371,606

Another aspect that was considered in our analysis was the reduction of Greenhouse Gas (GHG) emissions since the installation of a renewable energy system has an impact on the amount of GHG emissions generated for energy production.

NLH specified that it uses a value of 2.791 kg of CO_2 for each litre of diesel fuel burned in the gensets it operates. Based on this number, Hatch calculated that the amount of avoided GHG emissions for each project configuration based on the optimal scenario. The results are shown in the table below.

Table 6-6: Avoided CO_2 Emissions

Project	Project description	Avoided Emissions of CO_2 (tonnes) over 1 Year	Avoided Emissions of CO_2 (tonnes) over 20 years
Nain	2 EWT900	3,421	68,421
Hopedale	1EWT900	2,019	40,373
Makkovik	1EWT900	1,450	29,009
L'Anse au Loup	-	-	-
Cartwright	1EWT900	1,429	28,586
Total		8,319	166,389

Note: As of 2010, a total of 8.9 million tonnes per year of GHG emissions were estimated for NL and the installation of 5 EWT900 WTG in 4 communities, would equal to 0.09 % of province's total emissions.

6.4 Project Ranking

Since the costs are preliminary and additional cost input are required, the net present value (NPV), which summarises the total value of the project, was not used to rank the projects.

There are a number of factors that can be used to rank the projects such as costs of energy, cost of energy savings per kWh, total costs savings, fuel savings, total CapEx costs and net dollar savings over the project lifetime.

The first comparison looked at existing energy costs versus the optimal wind-diesel energy costs. Project ranking was done by considering the reduction of the cost of energy ($/kWh) for the electrical supply system retained compared to the base case (no WTG).

Table 6-7: Project Ranking Method 1

Project	No WTG Cost of Energy ($/kWh)	Opt. System Cost of Energy ($/kWh)	Cost of Energy Savings ($/kWh)	Ranking
Nain	0.321	0.263	0.0579	2
Hopedale	0.327	0.262	0.0646	1
Makkovik	0.325	0.279	0.0461	3
L'Anse au Loup	0.130	0.130	0	5
Cartwright	0.323	0.279	0.0445	4

The second comparison was done to evaluate overall annual energy savings. The project ranking was established by comparing the discount on the yearly cost of energy for each community. This is shown in the table below using the 2015 forecasted energy and the unit cost of energy savings, as provided in the table above.

Table 6-8: Project Ranking Method 2

Project	2015 Forecasted Energy Demand (MWh)	Unit Cost of Energy Savings ($/kWh)	Cost of Energy Savings ($/yr)	Ranking
Nain	9,019	0.0579	$522,376	1
Hopedale	5,334	0.0646	$344,375	2
Makkovik	4,175	0.0461	$192,647	4
L'Anse au Loup	26,919	0	-	5
Cartwright	4,500	0.0445	$200,241	3

The third comparison was done by evaluating the potential yearly fuel savings and the estimated total project CapEx (according to the preliminary cost analysis) and the net savings over the project lifetime.

When combining the preliminary CapEx and the potential estimated fuel savings over the project life (20 years), Nain has been identified as the top ranked site based on the considerations used in this preliminary analysis. Further studies will allow to better defined the viability of each project and their respective ranking based on pre-determined criteria prior to project implementation.

Table 6-9: Project Ranking Method 3

Project	Yearly Fuel Savings	Ranking	Total project CapEx	Ranking	Net Savings Over the Project Life	Ranking
Nain	$1,461,339	1	$9,946,223	4	$19,280,557	1
Hopedale	$854,928	2	$5,151,889	3	$11,946,671	2
Makkovik	$660,449	3	$4,869,717	2	$8,339,263	3
L'Anse au Loup	-	5	N/A	5	-	5
Cartwright	$610,325	4	$4,834,446	1	$7,372,054	4

Below is a summary of aforementioned rankings which identifies the top ranked site with the best (lowest) total score.

Table 6-10: Combined Project Ranking

Project	Unit Cost of Energy Ranking	Community Cost of Energy Saving Ranking	Fuel Savings Ranking	Net Savings (Fuel – CapEx) Ranking	Total Score	Overall Ranking
Nain	2	1	1	1	5	1
Hopedale	1	2	2	2	7	2
Makkovik	3	4	3	3	13	3
Cartwright	4	3	4	4	15	4
L'Anse au Loup	5	5	5	5	20	5

6.5 Additional studies

The Coastal Labrador Wind Monitoring Program was a prefeasibility study and additional studies and validations will be required prior to initiating the detailed design phase and implementation. Many studies and actions will be iterative in nature and will require validation in the planning and implementation phase. Based on a standard project development plan, the following additional studies will need to be completed for the projects that are selected for further development:

- Community consultation to validate location and project particulars,
- Review potential ownership, O & M and financing options,
- Detailed turbine selection and pricing,
- Completion of electrical and mechanical stability study,
- Completion of a constructability and logistic study based on turbine selected,

- Complete detailed design, and
- Prepare contractual agreements for the turbine, construction and O & M.

As mentioned in section 6.2, the electrical stability study will assist in determining the quantity of spinning reserve needed to ensure grid stability. The latter depends on the amount of wind turbines and their technical specifications and the specific anticipated variations in each community. The cost of energy will most likely increase by an increase in spinning reserve. Note that these actions are listed in an order that may vary depending on the proposed development plan, ownership and operation model.

7. Conclusions and Recommendations

The Coastal Labrador Wind Monitoring Program was initiated in 2011 with the objective to identify potentially windy areas that also possess other desirable qualities for a wind energy development site. Wind data was collected with success from all five communities and confirmed good wind conditions in all five communities ranging from 6.5 m/sec to 7.7 m/sec. Wind resource assessments including a preliminary turbine selection were completed and overall energy estimates were compiled for all potential projects. The analysis to evaluate the financial feasibility to add wind to the existing diesel generation was completed and showed potential good financial viability for four of the five communities. Additional analysis will be required to validate the business case in each of the community. The preliminary analysis also indicates that the implementation of wind in the communities could potentially provide reduce energy costs and also potentially contribute to reduction of GHG.

The overall business case for the implementation of wind projects in Coastal Labrador communities will remain to be validated as additional studies and community consultation will be required prior to completion of the final design.

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Appendix A:
Wind Resource Assessment Report – Nain

Project Report

November 15, 2015

Newfoundland and Labrador Hydro
Nain Wind Project

Distribution

Trevor Andrew – NLH
Asim Haldar – NLH
Bob Moulton – NLH
Timothy Manning – NLH
Terry Gardiner – NLH
Louis Auger – Hatch
Dany Awad – Hatch
Ève-Line Brouillard - Hatch

Final Wind Resource Assessment Report

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DOCUMENT HISTORY

Revision	Date	Description
1	June 8, 2015	Draft Version
2	July 27, 2015	Final Version
3	August 1, 2015	Few modifications to the Final Version
4	November 15, 2015	Few edits based on comments from NLH on October 30, 2015 – Final Version

EXECUTIVE SUMMARY

In order to assess the potential of Nain site for wind power development, a wind resource assessment (WRA) was completed. The site is located near the community of Nain, Newfoundland and Labrador, Canada. The site was equipped with one met mast that is described in the table below.

Met Mast	Installation Date	Top Anemometer Height (m)	Elevation (m)	Data Collection* Starts…	Data Collection* Ends…
2601	October 30, 2013	35.0	165	October 30, 2013	April 30, 2015

* A 12 month period is selected to estimate the annual energy production

In the analysis, the quality control process demonstrated that the data recovery rates exceeded 94 % on all instruments which meets industry standards for wind measurement campaign. Erroneous or unreliable data were replaced with available redundant data from instruments on the same met mast since these are considered to be equivalent wind measurements.

The **wind speed** measured at the mast is **6.5 m/s** on average. The **winds are dominant from west and west-southwest** across the site.

The wind **turbulence intensity** observed at the site is generally **moderate**.

Given the land cover and topography at the mast the **wind shear exponent**, equal to **0.11**, is consistent with the expected value.

Met Mast	Period	Annual Average of Measured Wind Speed* (m/s)	Annual Average of Measured Turbulence Intensity* (%)	Annual Wind Shear
2601	December 1, 2013 to November 30, 2014	6.5	12.6	0.11

** at Top Anemometer Height*

During the data quality control process, icing events were detected on anemometers and wind vanes. **Icing** which affected anemometers**,** occurred **5.0% of the time** at the site. Given the site elevation and the temperatures associated with these events, it is likely that about 62% of these events were caused by freezing rain and about 38% were caused by rime ice. Icing events mainly occurred during the months of April, May and September to December.

Temperature data were collected at the mast. The monthly averages range from **-19.6°C** in February to **11.7°C** in August, with an **annual average** of **-4.1°C** for the analysis period. The coldest 10-minute temperature recording during the data collection period was -32.9°C.

The **air density** was calculated at the mast according to the elevation and the local temperature. The annual value is **1.31 kg/m^3**.

The annual average power density is **416 W/m²**. The most powerful winds come from west-southwest to west-northwest across the site.

In order to estimate the **long-term wind regime** at the site, several potential **reference stations** with historical data were selected.

The **Nain station** monitored by Environment Canada, located 3 km away from the potential wind farm site, was selected as the reference station for the long-term extrapolation of the data. The reference station data was then correlated to met mast 2601 and used to translate the short-term data into long-term estimates.

The long-term estimates were then extrapolated from measurement height to hub height.

Met Mast	Period	Estimated Long-term Wind Speed at Top Anemometer Height (m/s)	Estimated Long-term Wind Speed at Hub Height (m/s) at 37 m / 40 m
2601	December 1, 2013 to November 30, 2014	6.5	6.7 / 6.7

The wind resource estimated at the mast was used to compute the wind flow across the project area. The wind flow was calculated with WAsP 11.01.0016 software, which is an appropriate model for the Nain project area which exhibits a moderate terrain complexity.

This wind flow was used to optimise the layout of the potential wind farm and to estimate the energy production with WindFarmer software.

A preliminary turbine selection analysis was completed and two turbine models were selected: Emergya Wind Technologies 900 kW (EWT900) and Northern power 100 (NPS100 Arctic). These models have proven technology in cold and icy environments and are suitable for wind-diesel generation in remote community.

A wind farm layout optimisation was completed taking in consideration energy production, information from the preliminary environmental screening and turbine extreme operating condition.

The main results of the energy production modeling are presented below. Additional losses include blade soiling, icing, collection network losses, auxiliary power consumption, wind turbines availability, high wind hysteresis, low temperature shutdown, collection network outage and grid availability.

Layout	Wind Farm Capacity (kW)	Net Energy Production (MWh/year)	Net Capacity Factor (%)	Wake Losses (%)	Additional Losses (%)
Layout 1 - EWT900	1800	6,150	39.0	0.5	14.6
Layout 2 - NPS100 Arctic	1200	4,058	38.6	2.5	14.3

Other energy production scenarios will be covered under separate portion of the wind penetration report.

1. Introduction

Hatch has been mandated by Newfoundland and Labrador Hydro (NLH) to carry out a wind resource assessment (WRA) for a potential wind farm project , located 2 kilometres west of the community of Nain, Newfoundland and Labrador, Canada.

The site was instrumented with one meteorological ("met") mast. The installation was competed on October 30, 2013. The mast was equipped with sensors at several heights to measure wind speed, wind direction and temperature. The analysed data cover a total measurement period of one year.

The second section of this report presents an overview of the site and the measurement campaign.

The third section presents the main characteristics of the wind climate.

The fourth section details the process used to translate the measured short-term data into long-term data.

The fifth section presents the methodology used to obtain the wind flow map over the project area. The wind flow map optimises the wind farm layout and helps determine monthly and annual energy production estimates. The key resulting values of these estimations are provided, including a description of the losses considered in the net energy calculation.

2. General Information

This section summarises general information about the site, the meteorological (met) mast installed and the measurement campaign.

2.1 Site Description

2.1.1 Site Overview

The community of Nain is located in an inlet on the Labrador east coast, approximately 370 km north of Happy Valley-Goose Bay. The surroundings of the community consists mainly of bare rock hills with an average elevation of 200m above sea level.

Figure 2-1: Typical Landscape at the Nain Area

2.1.2 *Mast Location*

The location of met mast 2601 was chosen with agreement between Hatch and NLH. Hatch proceeded with the installation of the mast and followed industry standards [1].

Table 2-1 provides a description of the mast, including the exact coordinates and the elevation.

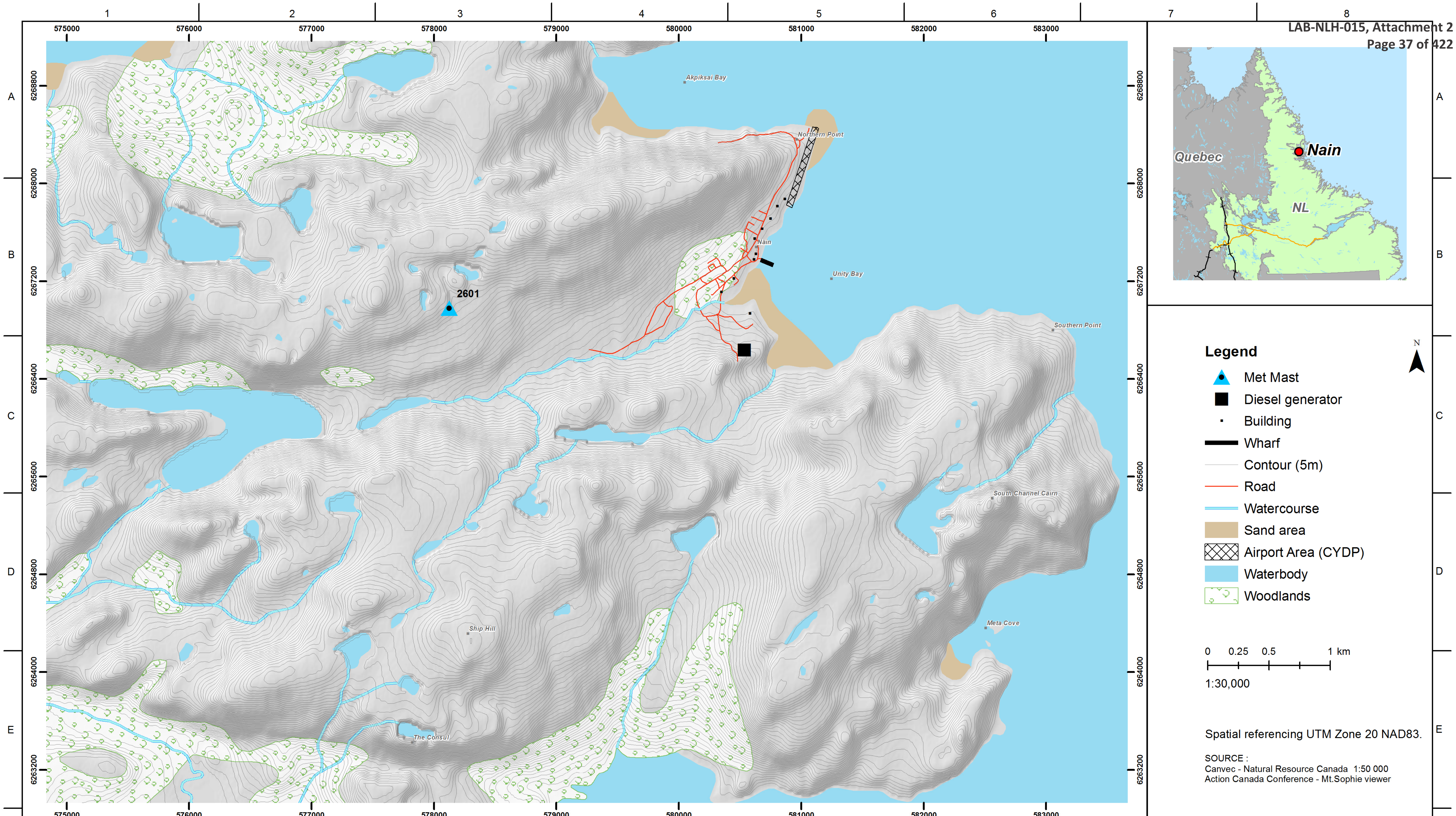
The location of the mast is shown on the map provided on next page.

Table 2-1: Met Mast Characteristics (Coordinate System: NAD83)

ID	Type	Diameter (m)	Height (m)	Latitude	Longitude	Elevation (m)
2601	Square Lattice	0.404	36	N 56° 32' 26.4"	W 61° 43' 46.3"	165

The Nain met mast 2601 is located west of the community on a rocky hill of approximately 200 metres.

Pictures have been provided in Appendix A with views in the four main geographical directions at the met mast.



NO.	DESCRIPTION	BY	CHK'D	APP'D	DATE

REVISIONS

HATCH

DESIGNED BY SLADJANA PAVLOVIC
DATE: February 27, 2015

DRAWN BY SLADJANA PAVLOVIC
DATE: February 27, 2015

CHECKED BY Dany Awad
DATE: February 27, 2015

NALCOR

Nain - Overview Map

SCALE BAR

REV. 3

2.2 Measurement Campaigns

The mast characteristics, instrumentation, installation dates and periods of data collection are provided in this section.

2.2.1 Installation and Collection Date

The following table provides the date of mast installation and the period of data collection used in the analysis.

Table 2-2: Installation Date and Period of Relevant Data Collection

ID	Installation date	Date and time of first data used	Date and time of last data used
2601	October 30, 2013	December 1, 2013, 00:00 AM	November 30, 2014, 11:50 PM

2.2.2 Instrumentation

2.2.2.1 Sensors Mounting

The met mast was equipped with anemometers and wind vanes mounted on booms at several heights. The dimensions of the booms, their heights and orientations on the mast, were designed to comply with the best practices in wind resource assessment as specified in [1] and [2].

For the met mast, the instrument and installation parameters are provided in the table below. All instruments and met mast underwent regular maintenance checks.

Heated anemometers and wind vanes were installed to increase the data recovery rate during icing periods. An Autonomous Power System (A.P.S.) developed by Hatch was installed to power supply the heating instruments. The A.P.S. consists of a set of batteries charged by a small wind turbine through a controller.

Table 2-3: Installation Parameters of Instruments at the met Mast

Channel	ID	Height (m)	Type	Date Installed	Date Uninstalled	Calibrated / Heated	Primary / Redundant
Mast 2601							
Data Acquisition System							
N/A	N/A	N/A	NRG Symphonie PLUS3	Oct 30, 2013	July 21, 2015	N/A	N/A
Anemometers							
#1	**A1**	**35.0**	**NRG #40C**	**Oct 30, 2013**	**July 21, 2015**	**Yes / No**	**P**
#2	A2	35.0	NRG Icefree III	Oct 30, 2013	July 21, 2015	Yes / Yes	R
#3	A3	26.0	NRG #40C	Oct 30, 2013	July 21, 2015	Yes / No	P
#4	A5	26.0	RMYoung 5103-AP	Oct 30, 2013	July 21, 2015	Yes / No	R

Channel	ID	Height (m)	Type	Date Installed	Date Uninstalled	Calibrated / Heated	Primary / Redundant
#13	A4	17.0	NRG #40C	Oct 30, 2013	July 21, 2015	Yes / No	P
Wind Vanes							
#7	**V1**	**33.0**	**NRG Icefree III**	**Oct 30, 2013**	**July 21, 2015**	**No / Yes**	**P**
#8	V2	26.0	RMYoung 5103-AP	Oct 30, 2013	July 21, 2015	No / No	R
#9	V3	15.0	NRG #200P	Oct 30, 2013	July 21, 2015	No / No	R
Temperature Sensor							
#10	T	34.0	NRG #110S	Oct 30, 2013	July 21, 2015	No / No	P

Note: Lines in bold font correspond to the anemometer and wind vane considered as the principal instruments for wind characterisation at the mast location.

2.2.2.2 Data Acquisition System

For met mast 2601, the instruments were connected to a data acquisition system which stored the data on a memory card. The data were then sent to Hatch computer network by a satellite communication system every 3 days.

3. Meteorological Data Analysis

This section presents a comprehensive analysis of the data collected. In the first section, the quality of the data is reviewed. The characteristics of the wind measured at the mast are then presented in Section 3.2 through a number of relevant parameters:

- monthly and annual average wind speeds;
- wind speed distribution;
- wind direction distribution;
- wind shear;
- turbulence intensity;
- 50-year recurrence wind speed.

In the final section, other climatic information such as measured temperature, calculated air density, wind power density and icing events is presented and discussed.

3.1 Quality Control

The quality and completeness of the data are key factors that determine the reliability of the wind resource assessment.

Data are collected periodically from the met masts and the quality of the data is analysed. This is done by applying a variety of logical and statistical tests, observing the concurrent readings from different instruments and relating these observations to the physical conditions at the site (e.g. wind shading, freezing potential, etc.). The process is semi-automated: the tests are implemented in a computer program developed by Hatch, but the expertise of quality analysts are required to accept, reject or replace data. There are many possible causes of erroneous data: faulty or damaged sensors, loose wire connections, broken wires, data logger malfunction, damaged mounting hardware, sensor calibration drift, icing events and different causes of shading (e.g. shading from the mast or from any obstacles at the site). A list of the possible error categories used during quality control is presented in Table 3-1. Data points that are deemed erroneous or unreliable are replaced by redundant data when available, or removed from the data set.

The data recovery rate for the analysis period is then calculated for each of the instruments using the following equation:

$$\text{Data recovery rate}\,(\%) = \frac{\text{Number of valid observations}}{\text{Number of potential observations}} * 100$$

The “Number of valid observations” is evaluated once erroneous or unreliable data are replaced with available redundant data. The “Number of potential observations” is the theoretical maximum number of measurements that could be recorded during the analysis period. A high data recovery rate ensures that the set of data available is representative of the wind resource over the measurement period.

Table 3-1: Quality Control Table

Error Categories
Unknown event
Icing or wet snow event
Static voltage discharge
Wind shading from tower
Wind shading from building
Wind vane deadband
Operator error
Equipment malfunction
Equipment service
Missing data (no value possible)

3.1.1 Data Replacement Policy

Erroneous or unreliable data were replaced with available redundant data from instruments on the same met mast since these are considered to be equivalent wind measurements. Replacements were done directly or by using a linear regression equation. Direct replacement is applied to anemometers when the replaced and replacing instruments are of the same model, calibrated, at the same height, and well correlated. Direct replacement is also applied to wind vanes as long as they are well correlated.

An acceptable percentage of the dataset is replaced by equivalent instruments (e.g. A1-A2: 9% of replacement) and it is considered to have a small impact on the uncertainty of the measurements.

3.1.2 Recovery Rates

The following table presents the recovery rates calculated for each instrument after quality control and after replacements have been completed according to the replacement policy.

Table 3-2: Instruments Data Recovery Rates

Mast ID	A1	A3	A4	V1	T
2601	97.8%	97.7%	94.3%	96.5%	100.0%

Note that the recovery rates for the following instruments are identical, given the replacement policy:

- A1 and A2; A3 and A5
- V1, V2 and V3

3.1.3 Data History

The data recovery rates exceed industry standards [5]. A number of data were affected for short periods of time by usual effects, such as shading effect and short period of icing events, and were removed.

3.2 Wind Characteristics

3.2.1 Annual and Monthly Wind Speed

The monthly wind speeds measured at each anemometer are shown in the following figures for mast 2601. The data are presented in two formats (see Figure 3-1 and Figure 3-2):

a) for all instruments, the averaged monthly wind speed measured;
b) for A1, all monthly wind speeds are also reported.

Although the results for anemometers A2 and A5 are presented, they will not be considered in further calculations as these sensors were used primarily for quality control and replacement purposes.

As expected, the data confirms that wind speeds increase with height above ground level (see section 3.2.4 for a description of wind shear). Furthermore, the graphs show the seasonal pattern of wind, which decreases towards summer months and increases towards winter months.

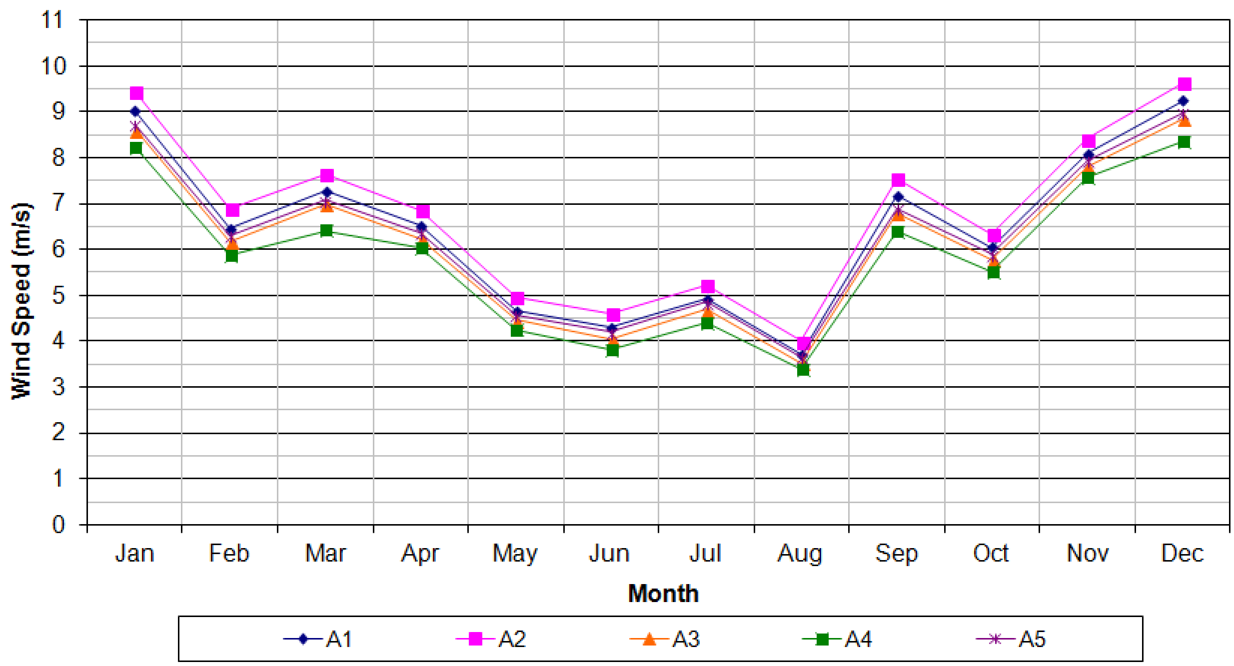


Figure 3-1: Averaged Monthly Wind Speeds for Each Anemometer at Mast 2601, December 1, 2013 to November 30, 2014

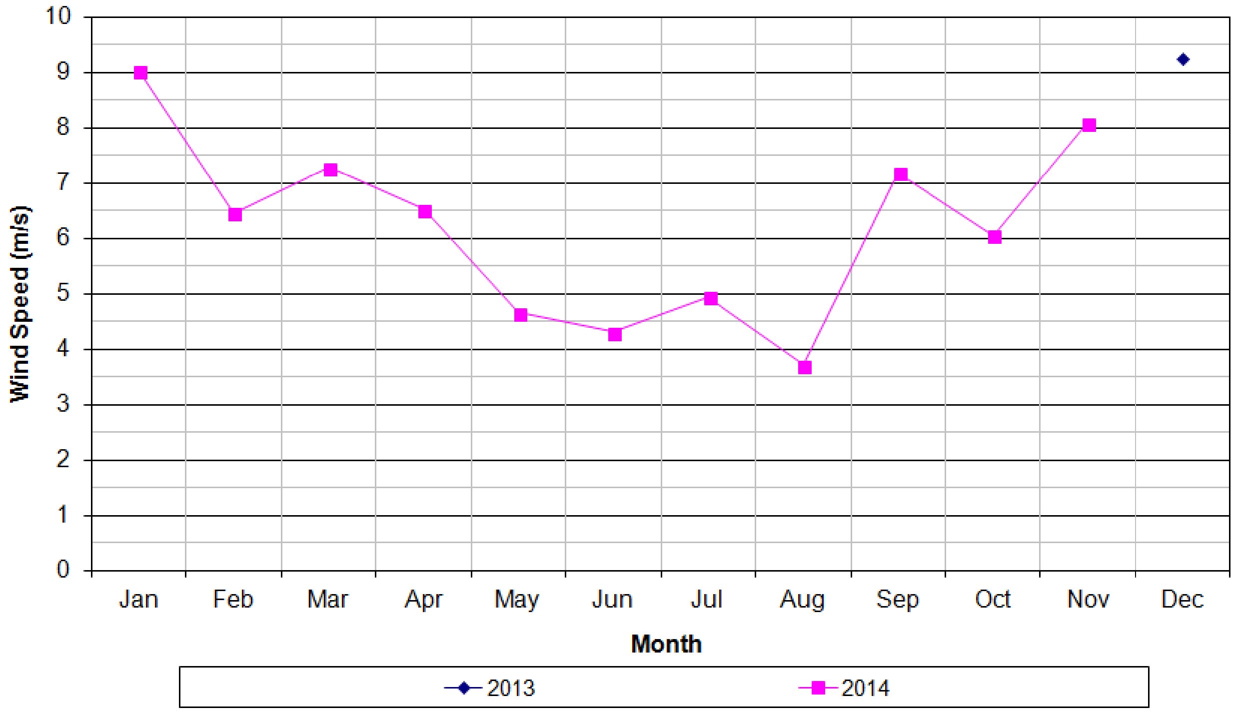


Figure 3-2: Monthly Wind Speeds Measured at the Top Anemometer at Mast 2601, December 1, 2013 to November 30, 2014

The following table provides, the average wind speed and the maximum 1-second gust observed, and specifies the averaging method used and the period of data considered. The averaging method varies as it depends upon the available data set:

- Annual: average of the wind speed recorded over one or more full years.
- Annualised: the annualised wind speed is a weighted wind speed that is calculated from all available monthly average wind speeds–e.g. if 2 values are available for January and only one is available for February, the February value will have twice the weight of each January value in the final average.
- Average: due to insufficient data collection, the annual average wind speed was not calculated. The value given is the average of all available data.

Table 3-3: Wind Speed Characteristics at the Mast

Mast	Top Anemometer Height (m)	Period	Average Wind Speed (m/s)	Maximum 1-second gust (m/s)	Method
2601	35.0	December 1, 2013 to November 30, 2014	6.5	44.9	Annual

3.2.2 *Wind Speed Frequency Distribution*

The frequency distribution of wind speeds helps to evaluate how much power is contained in the wind (power is proportional to the cube of the wind speed). Wind turbines will produce more power as the wind speed increases (until reaching the "rated" value). Thus, as the frequency of higher wind speeds increases, more power can be produced.

Annual frequency distributions generally exhibit a Weibull shape that is controlled by its "scale factor" (closely linked to the average wind speed) and its shape factor.

The wind speed frequency distribution graph is presented below for the mast[1].

2601, anemometer A1, December 1, 2013 to November 30, 2014

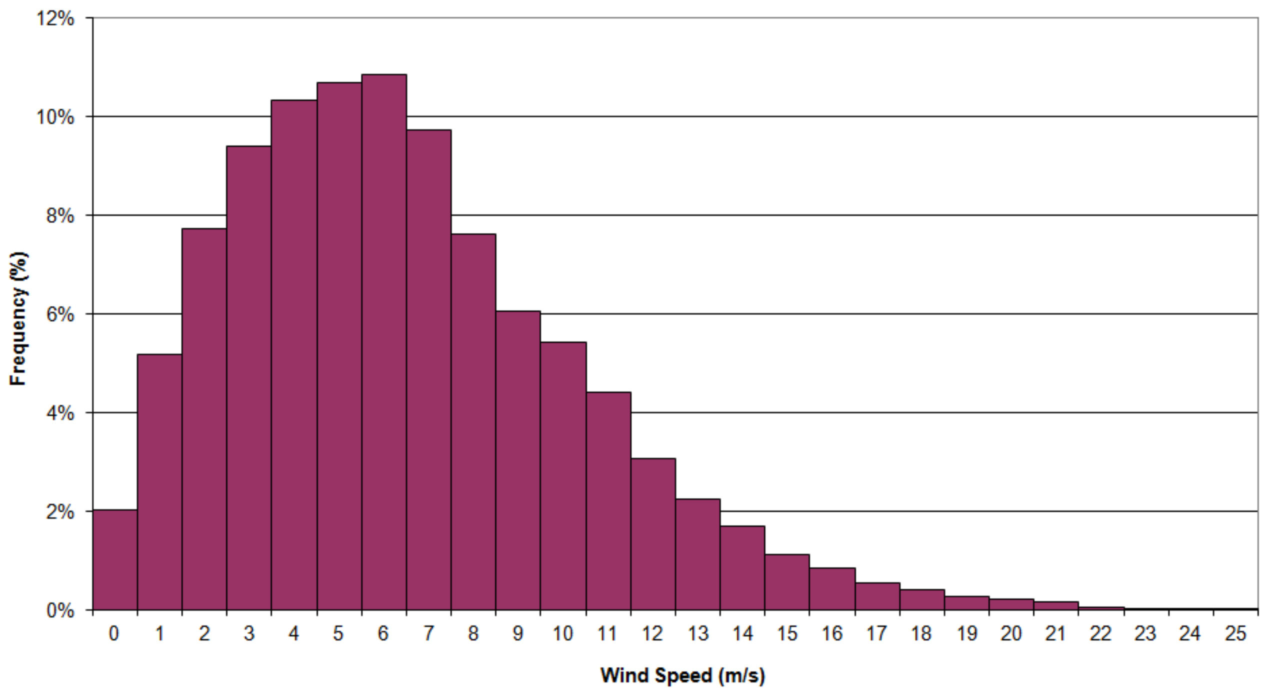


Figure 3-3: Wind Speed Frequency Distribution Graph

3.2.3 *Wind Rose*

The wind rose graph is presented below. The wind rose is divided into the conventional 16 compass sectors (22.5º wide sectors). Note that all compass orientations referenced in this report are based on the true geographic north, rather than the magnetic north.

[1] The 0 m/s wind speed bin indicates the fraction of the total number of measurements with a wind speed between 0 to 0.5 m/s. The other bins are 1 m/s wide and centered on the integer value (e.g.: the 1 m/s wind speed bin indicates the fraction with a wind speed between 0.5 to 1.5 m/s).

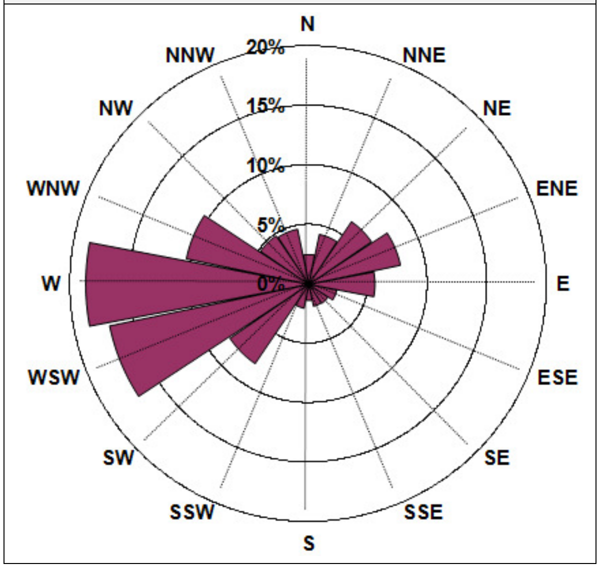


Figure 3-4: Wind Rose Graph

The wind rose indicates that a significant proportion of the wind blows from west and west-southwest, across the project area.

Note that wind roses are not adjusted to the long-term. Moreover, differences in wind directions between the levels of measurement are small enough to be neglected. As a consequence, the present wind rose will be considered as representative of the long-term wind rose at hub height.

3.2.4 Wind Shear

Wind speeds typically increase with height above the ground, because the frictional drag decreases with altitude. The increase in wind speed with height is referred to as wind shear and is commonly modeled either by a logarithmic law or by a power law.

When the power law is used, the wind shear can be quantified by a wind shear exponent. “Rough” surfaces, such as forested lands and urban areas, have a more pronounced frictional drag than “smooth” surfaces, such as a snow covered field or grasslands–the former will be associated with higher wind shear exponents. Over a smooth, level, grass-covered terrain, the wind shear exponent is typically around 0.14; over snow or calm sea it may be as low as 0.10; and over urban areas or tall buildings it may be as high as 0.40.

The roughness is not the only surface property that has a direct effect on the wind shear. When there is dense vegetation, the vertical wind speed profile is displaced vertically above the canopy, thereby displacing the level of zero wind speed to a certain fraction of the vegetation height above the ground. The “displacement height” is defined as the height at which the zero wind speed level is displaced above the ground. The displacement height is taken into account in all wind shear estimations.

Finally, large topographic variations over short distances may also impact the wind vertical profile and thus affect the wind shear.

Hatch recommends using the log law to estimate the wind shear at mast locations. Internal studies have shown that the accuracy of the wind shear estimate is slightly improved with the log law when compared to the power law. When available, three wind speed measurements, each at a different height, are used and a log law curve is fitted through the average wind speeds at these heights. With the log law, the parameter that reflects roughness is called the roughness length, instead of the wind shear exponent. However, an equivalent wind shear exponent is calculated between the top anemometer height on a mast and the hub height for easier interpretation.

The equivalent wind shear exponent presented in this report was calculated between the top anemometer height of the mast and hub heights of 37 m and 40 m. The calculation was based on the measured wind speed at the anemometer height and the wind speed extrapolated to hub height by the log law method. The log law parameters were determined by fitting a logarithmic curve through the average measured wind speeds at the three measurement heights.

The average equivalent wind shear exponents are reported in the following table.

Based on our knowledge about the vegetation in the area of the mast, this value conforms to expected results.

Table 3-4: Average Wind Shear at the Mast

Mast	Period	Wind Shear
2601	December 01, 2013 to November 30, 2014	0.11

3.2.5 *Turbulence Intensity*

Turbulence characterises the gustiness of wind or high frequency changes in wind speed and direction (high turbulence is typical of very irregular wind flows, contaminated by whirls or vortices). Turbulence increases in areas with very uneven terrain and behind obstacles, such as buildings. In wind farms, it interferes with the effective operation of the wind turbines and increases their wear and tear.

The measurement of turbulence is expressed in terms of turbulence intensity, which is the standard deviation of the wind speed divided by the mean wind speed, over a given period. Turbulence intensity is expressed as a percentage. In the present study, the standard deviation and mean speed values are calculated from 1 second wind speed data averaged over a 10 minute period.

Turbulence intensity is more erratic and more difficult to quantify at low wind speeds. As a consequence, only wind speeds in excess of 4 m/s are used to calculate of the turbulence intensity. This threshold is consistent with IEC standards for wind turbine power performance measurements [4].

The turbulence intensity value was calculated with the top anemometer data.

The average turbulence intensity is reported in the next table. This value is considered moderate according to the reference values defined in reference [2][2]. It is expected that turbulence will decrease with height, as the effect of obstacles and surface roughness will diminish.

Table 3-5: Average Turbulence Intensity at the Mast

Mast	Anemometer used	Period	Turbulence Intensity (%)
2601	A1	December 01, 2013 to November 30, 2014	12.6

3.2.6 50-year recurrence wind speed

The selected wind turbines Northern power 100 (NPS100) and Emergya Wind Technologies 900 kW (EWT900) are designed to survive a certain level of loading caused by an extreme wind event. Based on the specification provided by the manufacturers, the extreme survival wind speed at hub height is 59.5 m/s (see Appendix B).

At least 7 years of data at the met mast location or a nearby reference station is required. The Gumbel distribution was used to predict the once-in-fifty-year extreme wind speed. The data was extrapolated to hub heights of 37 m (NPS100) and 40 m (EWT) with a power law exponent of 0.11 suggested for gusts as per Wind Energy Handbook [2] and IEC 61400-1 standard.

In the case of Nain project, the met mast has only 18 months of data. Thus, data from Nain Environment Canada station were used and based on hourly data at 10 metres height. The data cover the period from 2006 to 2014. The 50-year recurrence maximum wind speeds were estimated to be 46.9 m/s at 37 m and 47.3 m/s at 40 m which respect the turbines' specifications.

3.3 Other Climatic Data

3.3.1 Temperature

Temperature was measured at a height of 34 m. The following table presents the average monthly and annual temperature measured. The coldest 10-minute temperature recording measured during the data collection period was -32.9°C in the morning of February 3, 2015.

Table 3-6: Average Monthly and Annual Temperatures

Mast ID	Monthly Air Temperature (°C)												Annual
	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	
2601	-17.4	-19.6	-16.8	-7.7	1.0	7.4	9.9	11.7	4.9	2.0	-7.5	-18.3	-4.1

[2] Low levels of turbulence intensity are defined as values less than or equal to 0.10, moderate levels are between 0.10 and 0.25, and high levels are greater than 0.25. This classification is for meteorological turbulence only; it should not be used in comparison with IEC models. Meteorological turbulence should not be used to establish the wind turbine class.

3.3.2 Air Density

Wind energy is directly proportional to the air density. Consequently, the amount of energy produced by a wind turbine will also be directly proportional to the air density at the turbine location. Air density decreases with increasing temperature, decreasing pressure and increasing altitude.

Based on the measured temperatures and the standard barometric pressure of 101.3 kPa at sea level, the monthly average air densities were calculated. Note that to correct for changes in atmospheric pressure with height, the calculations account for the site elevation. The values were calculated over the entire analysis period reported in Table 2-2.

Table 3-7: Monthly and Annual Average Air Density

Mast ID	Monthly Air Density (kg/m^3)												Annual
	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	
2601	1.34	1.36	1.34	1.30	1.26	1.23	1.22	1.21	1.24	1.25	1.30	1.35	1.31

3.3.3 Power density

Wind speed, wind direction and air density data can be combined to provide information about the average power density at mast location. Wind power density indicates how much energy is available at a given instant for conversion by a wind turbine[3]. For example, strong winds in the winter, when the air is colder and denser, will have a higher power density (i.e. carry more energy) than the same strong winds in the summer. Though power is an instantaneous value, it is calculated as an average over a given period of time.

Tables of the power density distribution per direction and per month were produced at the top anemometer height and are presented below.

At mast 2601, the most powerful winds come from west-southwest to west-northwest, and appear in winter months. The annual average power density is 416 W/m^2 at 35.0 m.

Table 3-8: Table of Wind Power Density per Direction, December 1, 2013 to November 30, 2014

Wind Power Density per Direction (W/m^2)															
N	NNE	NE	ENE	E	ESE	SE	SSE	S	SSW	SW	WSW	W	WNW	NW	NNW
250	278	233	137	78	415	144	76	56	59	167	556	710	713	339	330

Table 3-9: Table of Wind Power Density per Month, December 1, 2013 to November 30, 2014

Wind Power Density per Month (W/m^2)												Annual Average
Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	
962	306	522	406	142	116	149	78	447	255	582	777	416

[3] Note that the units "W/m^2" refer to m^2 of rotor swept area.

3.3.4 Icing Events

Icing affects the operation of wind turbines. Icing on any exposed part of the turbine can occur in the form of wet snow (generally associated with temperatures between 0°C to 1°C), super-cooled rain or drizzle (that can occur at temperatures between 0°C to -8°C, but mostly in the upper part of this range), or in-cloud icing (that can occur below - 2°C). Losses during production due to ice occur in several ways:

- Ice accumulation on the blades alters their aerodynamic profile, reducing the power output.

- Nacelle-mounted instruments accumulate ice and give inaccurate readings. The turbine control system may detect a fault condition due to the turbine output being much greater than expected. This expectation is based on the wind speed. As a result, the turbine will be shut down until the ice is removed from the instruments and the turbine is reset.

- Asymmetric icing causes mass or aerodynamic imbalance leading to vibrations. Control systems that sense vibrations will normally shut down when these vibrations occur.

Icing is a complex phenomenon and predicting icing from meteorological conditions is notoriously difficult, requires a good set of observations from a number of meteorology variables, and can be misleading. As no reliable instrument is presently available to detect and quantify icing events for the purpose of estimating their impact on wind energy production, Hatch uses several tests during data quality control to detect icing events: detection of unusual standard deviations or changes with time of wind speeds and directions, comparison of measurements from a heated anemometer and a standard anemometer at the same level, in parallel with the measurement of temperature.

These tests cannot distinguish between the different types of icing, but a rough approximation can be done by utilising the temperature ranges measured during icing events. Therefore, in the following estimate, we will consider two categories: "glaze", which is assumed to include wet snow, super-cooled rain and drizzle, and "rime ice", which is assumed to include in-cloud icing and the very low temperature part of super-cooled rain or drizzle. The threshold of -5°C is used to differentiate between rime ice (below -5°C) and glaze (above -5°C).

The following table presents the estimated number of icing events in a month and the type of event assumed to occur in the project area. This estimate is based on the average of icing events detected on the mast during the measurement campaign.

Table 3-10: Estimated Hours of Icing Events, October 30, 2013 to April 30, 2015

	January	**February**	**March**	**April**	**May**	**June**	
Hours	12	15	25	65	54	1	
Rime	100%	100%	80%	10%	0%	0%	
Glaze	0%	0%	20%	90%	100%	100%	
	July	**August**	**September**	**October**	**November**	**December**	**Annual Average**
Hours	0	0	49	38	87	94	438
Rime	-	-	0%	0%	30%	100%	38%
Glaze	-	-	100%	100%	70%	0%	62%

4. Long-term Wind Speed at Hub Height

The previous section presented the analysis of the wind regime as it was measured by the met mast installed on the project site. However, to forecast the energy production of a wind power plant, wind data that represents the historical wind conditions at the site are required. Unfortunately, wind resource assessments are generally conducted for a limited number of years, often no more than one or two years, which is not sufficient to capture the year-to-year variability of wind. For example, in North America, the annual average wind speed exhibits a standard deviation of about 6% (or 1σ from a normal distribution) of the long-term average wind speed. Hence, the maximum deviation from the average wind speeds could reach as much as 20% (or 3.3σ). Consequently, it is necessary to translate the measured short term data into long-term data. This is done through a correlation/adjustment process that makes reference to a meteorological station where historical data is available.

Moreover, when the top anemometers of the met masts are mounted at a lower height than the expected hub height of the wind turbines, the long-term data must also be extrapolated from these anemometer heights to the wind turbine’s hub height.

The long-term projection process is presented in the next section and is followed by the extrapolation to hub height.

4.1 Long-term Projection

When required, selecting a reference data set to perform a long-term correlation and adjustment is determined by the following process:

- A quality assessment of the potential long-term reference stations for the site (history, similarity of the local climate with regards to the meteorology mast climate, etc.);

- A quality assessment of the correlation equations obtained with acceptable long-term reference stations and the measured data for the concurrent period;

- A comparison of the long-term correlation results obtained with all acceptable reference stations;

- A crosscheck of the resulting long-term adjustments with the measured data and the long-term trends at nearby reference stations or at a regional level.

Once the reference data set is selected, it is used to adjust the met mast data to long-term conditions. This can be achieved either by synthesizing non existing years of data at the met mast site or by applying an adjustment factor to the measured data in order to better reflect the reference period. The process is as follows:

- The measured data from the met mast is correlated with the reference data set;

- If the correlation parameters meet the synthesis criteria, then data are synthesized at the measurement mast for the complete reference data period; this method is referred to as the Measure-Correlate-Predict (MCP);

- If the criteria are not met but a good correlation can still be obtained with hourly or daily intervals, then the measured data set is scaled up (or down) to long-term using the reference long-term average wind speed and the correlation equation obtained; this method is referred to as the Long-term Adjustment;

- If no correlation can be clearly established between a reference site and the met mast site, the measured data stays unchanged.

4.1.1 *Selection of reference data set*

The present section summarises the results of the analysis.

Among the possible set of reference stations, one station was selected and considered suitable for the long-term projection of the data at the met mast. This station is Nain monitored by Environment Canada (EC). The location of this station is given in the table below.

Table 4-1: Identification of the Long-term Reference

Name	ID	Instruments Height (m)	Latitude	Longitude	Elevation (m)
Nain	**8502799**	10.0	N 56° 33' 00.0"	W 61° 41' 00.0"	7.6

4.1.2 *Long-term Adjustment*

The long-term adjustment consists of:

- Correlating short term data at the met mast with short term data at the reference station;

- Using the obtained linear regression equation, Y = m X + b, where X represents the long-term average wind speed at the reference station and Y is the estimated long-term average at the met mast;

- Applying an adjustment factor (to speed up or scale down) to the met mast short term data in order to obtain an average wind speed equal to the estimated long-term average at met mast (i.e. Y).

For masts 2601, which displayed 18 months of data recorded, the long-term adjustment method was used for the long-term projection.

The wind speed data of the met mast was correlated to the concurrent wind speed data at the long-term reference station Nain. Good correlation results were obtained with daily average values (R^2 greater than or equal to 0.7 is good correlation, above 0.85 is excellent). The results of the correlation are given in the following table. Linear regression equations were used to compare the data, where *m* is the slope of the equation, *b* is the intercept, and R^2 is the coefficient of determination.

Table 4-2: Correlations between Reference Station and met mast Wind Speeds

Reference Station	Met Mast	Correlation Period		Daily Wind Speed Correlations		
		Beginning	End	m	b	R^2
Nain	**2601**	December 1, 2013	November 30, 2014	0.885	1.8	0.84

The regression equations were then used to estimate the long-term average wind speed at the mast as a function of the long-term wind speed at the reference station. The estimated long-term average at the Nain station is 5.3 m/s. It was estimated by averaging all annual averages over the period 2006 to 2014 (except 2012 having very low recovery rate). The results are presented in the following table.

Table 4-3: Long-term Adjustment factor at the met mast

Met Mast	Wind Speed over Correlation Period (m/s)	Long-term Annual Wind Speed (m/s)	Adjustment Factor (%)
2601	6.5	6.5	0.4

Finally, the 10-minute measured data recorded at the met mast were scaled by the adjustment factor to reflect the long-term value. In terms of the wind direction data, the one-year dataset for the met mast remained untouched. As a result, the mast has a set of wind speeds and wind directions that are the best estimate of the long-term wind regime.

4.2 Extrapolation to Hub Height

The wind shear exponent, calculated with the measured data, was used to adjust the dataset to hub heights. The results are presented in the following table.

Table 4-4: Estimated Long-term Wind Speed at Hub Heights*

Met Mast	Estimated Long-term Wind Speed at Top Anemometer Height (m/s)	Estimated Long-term Wind Speed at Hub Height (m/s)	
		37 m	**40 m**
2601	6.5	6.7	6.7

* Estimated using the calculated wind shear

5. Wind Resource Mapping and Projected Energy Production

Met masts provide a local estimate of the wind resource. Met mast locations are chosen based on how representative they are of the project site and in particular for potential wind turbine locations. However, since the number of met masts is usually limited compared to the expected number of wind turbines, it is necessary to build a wind flow map based on these measurements to extend the wind resource assessment to the whole project area.

Wind modeling software, such as MS-Micro and WAsP, are known to produce erroneous wind flows over complex terrain. In this case, Hatch applies a method based on the Ruggedness Index (RIX) to calculate the wind flow for each mast data set while correcting errors on wind speed[4]. All produced wind flows are then merged by a distance-weighting process. When the RIX correction is not applicable, wind flows are calculated with each mast dataset and simply merged together by a distance-weighting process, without a RIX correction.

Once the wind flow map is built, it is possible to optimise the size and layout of the foreseen wind farm for the project, and then to calculate the projected energy production. When necessary, wind turbine hub heights as well as met mast heights are corrected with the estimated displacement height. This is computed to account for the influence of trees on the wind flow (see section 3.2.4). These corrections result in an effective hub height for each wind turbine.

The wind flow and energy production are calculated with specialised software that require, apart from the met masts long-term data, background maps that contain the information on topography, elevation, roughness lengths (related to the land cover) and potential obstacles. This is also used in conjunction with the wind turbine characteristics. Finally, wind farm losses must be estimated in order to complete the energy estimate.

The first part of this section introduces the information and the methodology used to calculate the wind flow.

The next part will present the optimisation process and the results in terms of energy production.

The software used to map the wind resource and to calculate the energy production include:

- WAsP Issue 11.01.0016 from Risø for wind resource mapping;
- Wind Farmer Issue 4.2.2 from Garrad Hassan for layout optimisation and energy production calculations.

5.1 Background Data

5.1.1 Topography and elevation

The topographic and elevation data comes from files provided by the National Topographic Data Base (NTDB).

The contour line interval is 5 m within the project area and 20 m outside.

[4] Bowen, A.J. and N.G. Mortensen (2004). WAsP prediction errors due to site orography. Risø-R-995(EN). Risø National Laboratory, Roskilde. 65 pp.

5.1.2 Roughness

The base map for roughness lengths was determined from land cover information included in the NTDB files. This map was then checked and corrected using satellite imagery from Google Earth. Around mast location and wind turbines, pictures and information noted during site visits were also used to check and modify the land cover information. The spatial resolution considered for the roughness lengths is 30 m.

The following table details the roughness lengths used by land cover category.

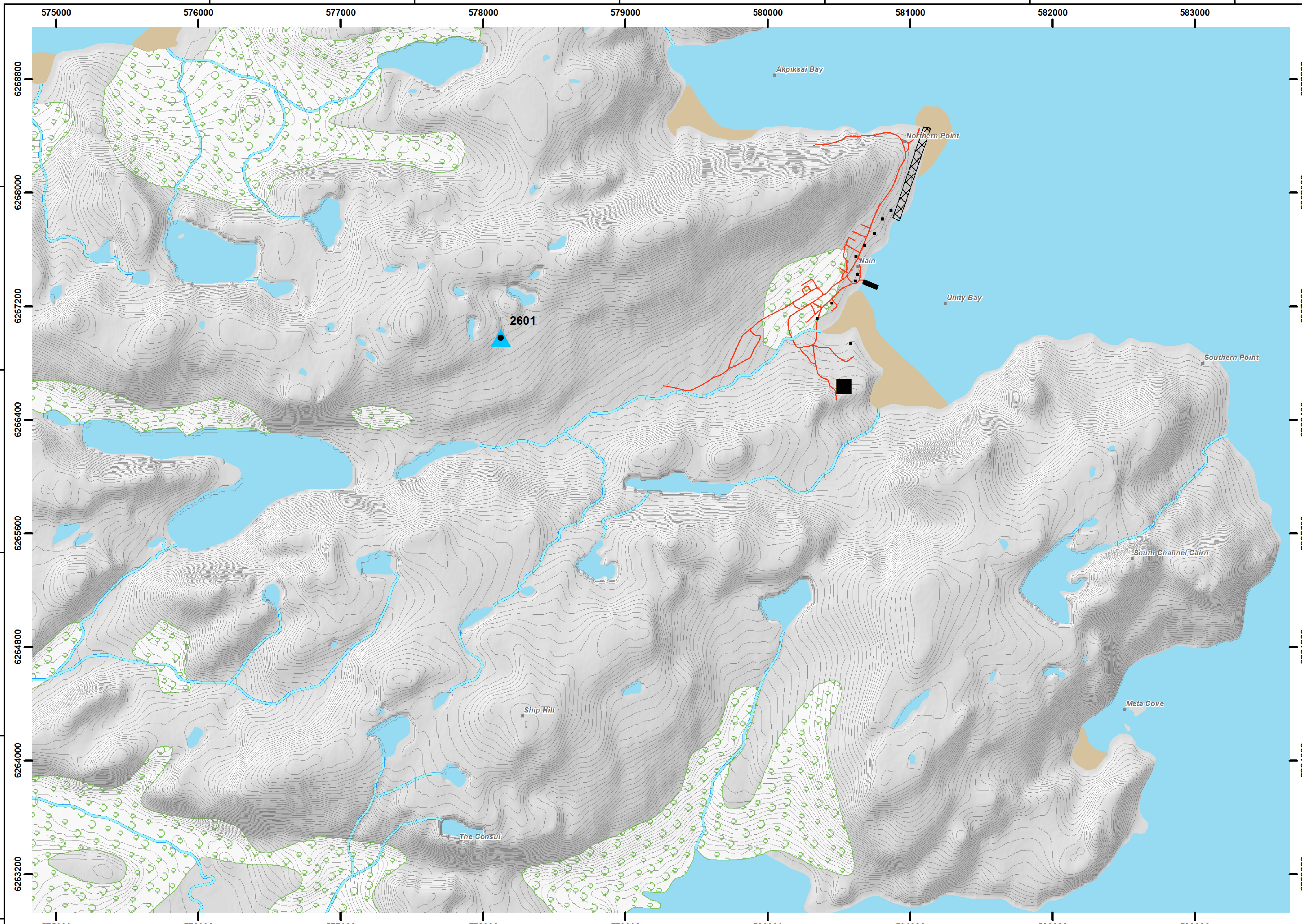
Table 5-1: Roughness Lengths Categories

Land Cover Type	Roughness Length (m)
Open farmland, high grass	0.04
Forest	0.8
Water	0
Building	0.5

5.1.3 Background Map

The background map, showing topography and contour lines is provided on the next page.

Safety ● Quality ● Sustainability ● Innovation



Legend

- Met Mast
- Diesel generator
- Building
- Wharf
- Contour (5m)
- Road
- Watercourse
- Sand area
- Airport Area (CYDP)
- Waterbody
- Woodlands

N

0 0.25 0.5 1 km

1:30,000

Spatial referencing UTM Zone 20 NAD83.

SOURCE :
Canvec - Natural Resource Canada 1:50 000
Action Canada Conference - Mt.Sophie viewer

NO	DESCRIPTION	BY	CHK'D	APP'D	DATE

REVISIONS

HATCH™

DESIGNED BY SLADJANA PAVLOVIC DATE: February 27, 2015	DRAWN BY SLADJANA PAVLOVIC DATE: February 27, 2015
CHECKED BY Dany Awad DATE: February 27, 2015	

NALCOR

Nain - Overview Map

SCALE BAR

REV. 3

5.2 Wind Flow Calculation

5.2.1 Terrain Complexity

The wind flow is produced over semi-complex terrain. Wind modeling software, such as MS-Micro (used in Windfarm) and WAsP, are known to produce erroneous wind flows over complex terrain. Depending on the topography, predicted wind speeds can be over or under-estimated at a given location. Errors can reach more than 20% in very complex areas.

In the present case, the complexity of the terrain is considered moderate and its effect on the modelled wind is not considered problematic.

5.2.2 Parameters

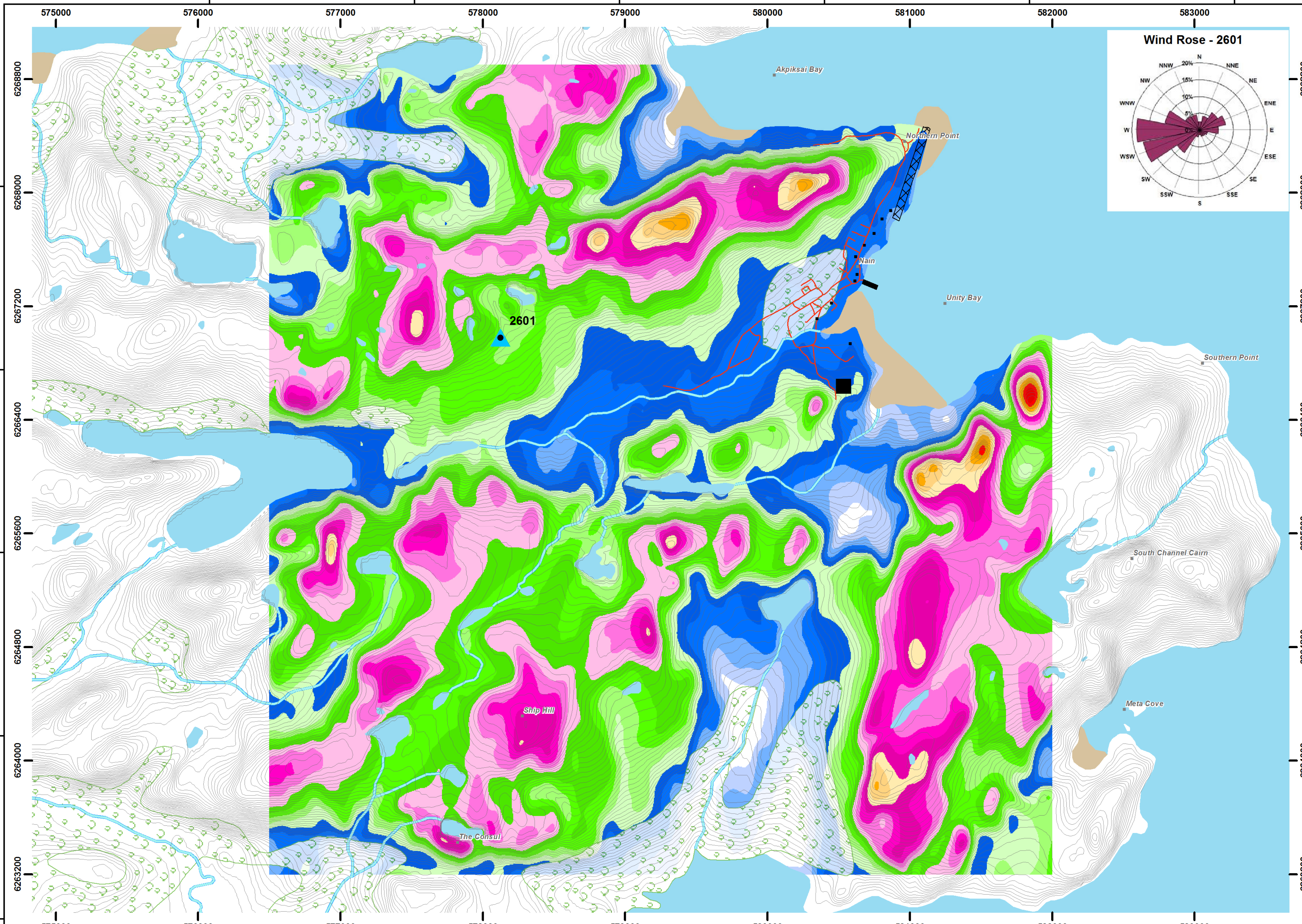
The following parameters were used to calculate the wind flow map.

Table 5-2: Wind Flow Calculation Parameters

Parameter	Value
Wind Resource Grid Spatial Resolution	50 m
Calculation Area	5.7 km by 5.7 km
Reference Mast	2601
Reference Height	Top Anemometer Height
Calculation height	37 m
Vertical Extrapolation Method	Based on measured wind shear
Roughness Change Model	WAsP Standard Model

5.2.3 Results

The wind flow map used for layout optimisation and energy production estimates is presented on the next page.



Legend

- Met Mast
- Diesel generator
- Building
- Wharf
- Contour (5m)
- Road
- Watercourse
- Sand area
- Airport Area (CYDP)
- Waterbody
- Woodlands

WindFlow (37m)

m/s

- < 5
- 5 - 5.25
- 5.25 - 5.5
- 5.5 - 5.75
- 5.75 - 6
- 6- 6.25
- 6.25 - 6.5
- 6.5 - 6.75
- 6.75 - 7
- 7 - 7.25
- 7.25 - 7.5
- 7.5 - 7.75
- 7.75 - 8
- 8 - 8.25
- 8.25 - 8.5
- 8.5 - 8.75
- 8.75 - 9
- 9 - 9.25
- 9.25 - 9.5
- 9.5 <

N

0 0.25 0.5 1 km

1:30,000

Spatial referencing UTM Zone 20 NAD83.

SOURCE :
Canvec - Natural Resource Canada 1:50 000
Action Canada Conference - Mt.Sophie viewer

NO	DESCRIPTION	BY	CHK'D	APP'D	DATE

REVISIONS

Wind resource map created by Hatch with WAsP 11.01.0016
Height of calculation: 37 m
Spatial resolution of wind resource grid: 50 m
Source file: Nain_2601_GridWRG_37m_WF2.grd
Source of data used to create the wind flow:
Topographic data are provided by the Center for Topographic Information (NRCan).
Meteorological data were collected from mast 2601, located 1.5 km on average from the center of the map, between 01/12/2013 and 30/11/2014. Data were controlled by Hatch. Met data were adjusted for long term with reference to station Environment Canada Nain # 8502799 (reference period 2006-2014).
It is believed that the present map gives a reliable overall picture of the wind resource. However, it is advised to confirm any information obtained from this map at any location by on-site measurements.

HATCH

DESIGNED BY
SLADJANA PAVLOVIC
DATE: February 27, 2015

DRAWN BY
SLADJANA PAVLOVIC
DATE: February 27, 2015

CHECKED BY
Dany Awad
DATE: February 27, 2015

NALCOR

Nain - Windflow 2

SCALE
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REV.
3

5.3 Forecasting Energy Production

The layout was initially designed in order to maximise energy production. Turbines were spread out inside the project boundaries to minimise wake effects. The preliminary environmental screening and turbine extreme operating conditions also contributed to set the turbine locations.

5.3.1 Preliminary Turbine Selection

A preliminary turbine selection was performed using Windographer software by comparing the performance of different turbines at the location of the met mast, where the dataset was recorded. The main parameters used for the comparison were the capacity factor of the wind turbine for the site specific conditions as well as the turbine purchase cost. Only turbines that meet the following criteria were considered:

- Site's turbine and turbulence class (IEC class II)
- Extreme wind and weather conditions (operation down to -40℃). The minimum 10-minute temperature recording of -32.9℃ during the monitoring campaign confirms the site conditions are within the operating range of the turbine.
- Turbine capacity ranges from 100 kW to 1,000 kW to meet the community load
- Wind turbine's dimensions and weight versus crane capacity and accessibility

Hub heights of about 40 m to 50 m were used for this preliminary analysis.

Standard losses considered include: 12.5% technical losses and 2% wake losses.

The following table provides a summary of the turbine comparison.

Table 5-3: Windographer Results at the Mast Location

Turbine type	Turbine Class	Hub height (m)	Turbine Capacity (kW)	Mean Energy Output (MWh/yr)	Capacity Factor (%)	Turbine purchase cost ($)
Northern Power NPS100 Arctic	IIA	37	100	234	26.7	325,000
Aeronautica AW/Siva29-250	IIA/IIIA	37	250	514	23.5	656,000
Aeronautica AW/Siva47-500	IB/IIA	47	500	1,353	30.9	1,632,000
EWT DW52-250 (EWT250)	IIA	37	250	1,008	46.0	1,980,000
EWT DW52-500 (EWT500)	IIA	37	500	1,536	35.1	1,990,000
EWT DW52-900 (EWT900)	IIA	40	900	1,972	25.0	2,000,000

The capacity factors listed above in table 5-3 are taken from Windographer and may change as a function of the site's optimized layout and should only be used for turbine comparison.

Due the lack of proven experience in remote arctic conditions, the Aeronautica wind turbine models were discarded from the analysis. Northern Power and EWT wind turbines have

been installed and are operating in similar site conditions in Nome, Alaska for EWT or in Kasigluk, Alaska for Northern Power and were thus further compared as part of the analysis.

The average community load at Nain during the project lifetime is around 1200 kW. The following table shows the results of the WindFarmer optimization models using the required number of turbines to meet that load. The turbines were ranked based on their capacity factor, energy output and simple payback.

Table 5-4: Preliminary Turbine Selection Results

Turbine type	Number of wind turbine required	Total Capacity (kW)	Gross Energy Output (MWh/yr)	Gross Capacity Factor (%)	Total purchase cost (Million $)	Ranking
Northern Power NPS100 Arctic	**12**	**1200**	**4738**	**45.0**	**3.900**	**2**
EWT250	5	1250	7357	67.1	9.900	4
EWT500	3	1500	7562	57.5	5.970	3
EWT900	**2**	**1800**	**7201**	**45.6**	**4.000**	**1**

* Based on the gross energy output at 30 cents/kWh divided by the turbine purchase cost only.

Based on information provided by EWT, the 250 kW wind turbine has the same foundation design as the 500 kW and 900 kW machines and nearly the same price ($10,000 difference). Because of the similar turbine costs of the three EWT models, from a financial point of view, the EWT900 becomes the most suitable having the lowest simple payback, and would also benefit from potential lower constructability and BOP cost.

The Northern power NPS100 Arctic can also be considered as potential candidates for the Nain project since it is a proven turbine in arctic conditions, and would provide for more redundancy due to number of turbine. The NPS 100 has the advantage of being a smaller turbine and would be less difficult from a logistic and crane accessibility stand point.

The NPS100 and EWT900 turbines are two models that meet the wind class of the site and have proven technology for cold and icy environments.

Even though a more detailed turbine selection exercise will be required in later phase of the project, the NPS 100 and EWT900 are considered suitable candidate turbines in order to complete the preliminary energy estimates for the potential Nain project.

5.3.2 Layout Optimization

The following section shows the WindFarmer modeling results which further refines the energy estimates for the turbines selected at the potential turbine positions and to confirm the capacity factor values. The table below outlines the parameters and constraints assumed to influence optimisation.

Table 5-5: Layout Optimisation Parameters and Constraints

Parameter / Constraint	Value	
Annual Air Density	1.31 kg.m^{-3} at 199 m.a.s.l.	
Turbulence Intensity	12.6% at mast 2601 ***Note**: average value for information, the turbulence intensity is actually entered by wind-speed bins and by direction for energy prediction calculation*	
Exclusion areas	Due to the lack of information in regard to setbacks for wind energy projects in Newfoundland and Labrador, general restriction rules were used: - 500 m from habitations - 100 m from public roads - 50 m from lakes and rivers - 2 km by 1 km buffer zone from the airport track	
WTG Minimum Separation Distance	Elliptical separation: Minimum of 10 rotor diameters on long axis Minimum of 6 rotor diameters on short axis Bearing of long axis: 255 degrees	
WTG Model	EWT900	NPS100 Arctic
WTG Rated Power (kW)	900	100
WTG Rotor Diameter (m)	51.5	20.7
WTG Hub Height (m)	40.0	37.0
WTG Power Curve	See Appendix B	
WTG Thrust Curve	See Appendix B	
Number of WTG's	2	12
Wind Farm Capacity (kW)	1800	1200
Wake Model	Eddy Viscosity Model	
Maximum Slope	10 degrees	
Optimization Strategy	Layout designed in order to maximise energy production.	

The project layouts are presented at the end of this section.

The layouts are still considered preliminary. Land restrictions, communication corridors, noise and visual impacts, and other site-specific matters need to be evaluated through a detailed environmental assessment. Available land, road and collection system costs are also issues that will need to be addressed before the site layout can be finalized.

5.3.3 Energy production

Once the optimised layout has been produced, the energy production for each wind turbine is calculated. When necessary, wind turbine hub heights as wells as met mast heights are corrected with the estimated displacement height. This is computed to account for the influence of trees on the wind flow. These corrections result in an effective hub height for each wind turbine.

The calculation was executed with the power curves and thrust curves used for the optimisation and are presented in Appendix B. The additional losses are described in the next section.

Note that air density is corrected by the software for each turbine location according to its elevation.

The following table is a summary of the estimated energy production. Detailed energy figures are presented per wind turbine on the next page.

Table 5-6: Wind Farm Energy Production Summary

Item	Layout 1 - EWT900	Layout 2 - NPS100 Arctic
WTG Rated Power (kW)	900	100
WTG Rotor Diameter (m)	51.5	20.7
WTG Hub Height (m)	40.0	37.0
Number of Wind Turbines	2	12
Wind Farm Capacity (kW)	1800	1200
Mean Free Wind Speed across Wind Farm (m/s)	8.7	8.4
Average Wake Losses (%)	0.5	2.5
Energy Production Before Additional Losses* (MWh/yr)	7,201	4,738
Capacity Factor Before Additional Losses* (%)	45.6	45.0
Additional Losses (%)	14.6	14.3
Net Energy Production (P50) (MWh/yr)	**6,150**	**4,058**
Net Capacity Factor (%)	**39.0**	**38.6**

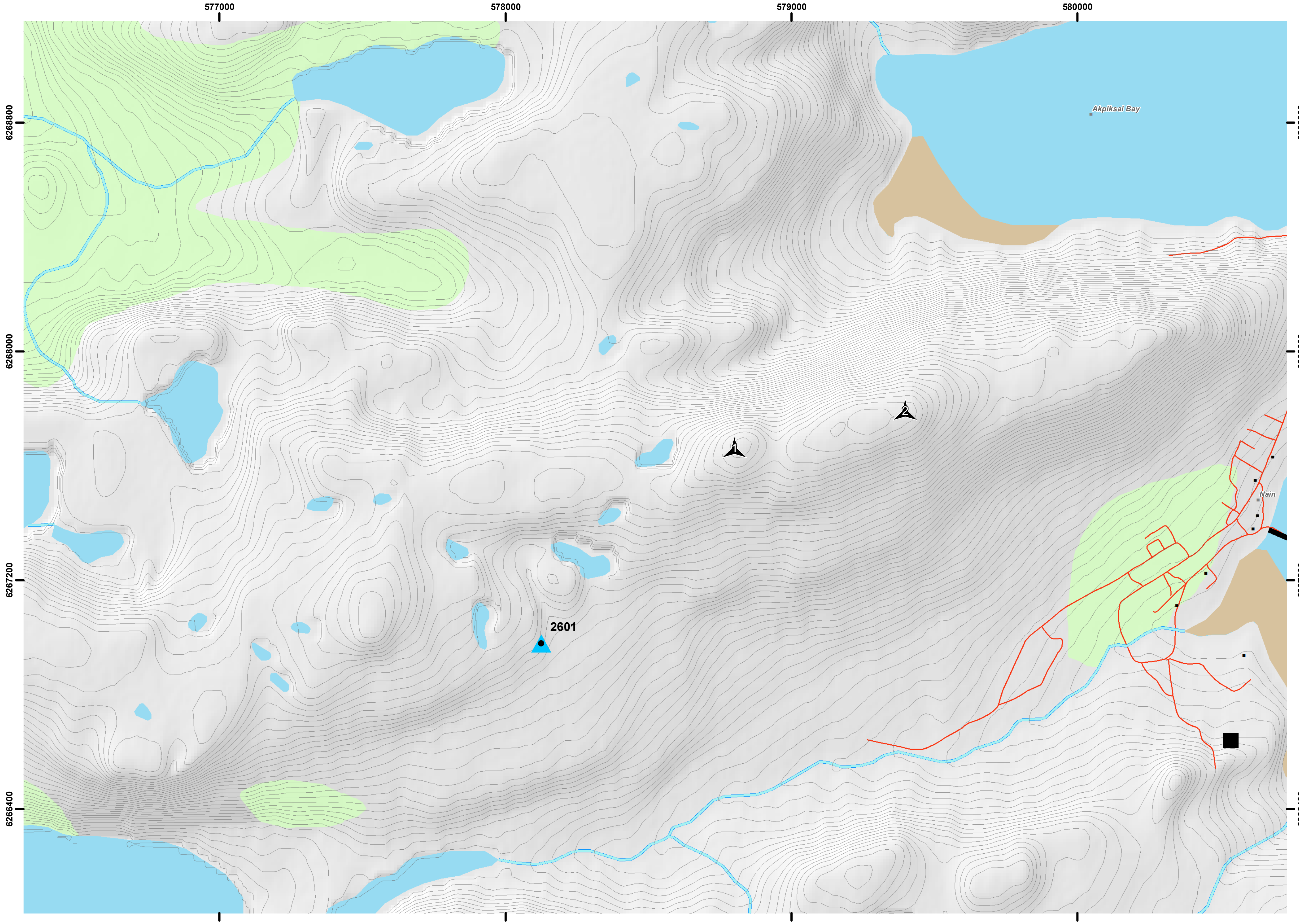
* Includes topographic effect and wake losses

Table 5-7: Forecasted Energy Production at Wind Turbines

Turbine ID	Easting (m)	Northing (m)	Altitude (m)	Mean Free Wind Speed (m/s)	Gross Energy Production* (MWh / Year)	Wake Losses (%)	Gross Energy - Wake* (MWh / Year)	Turbulence Intensity** (%)
Layout 1 - EWT900								
1	578801	6267665	250	8.5	3,563	0.1	3,559	12.6
2	579397	6267796	247	8.8	3.671	0.8	3,642	12.4
Layout 2 - NPS100 Arctic								
1	577543	6267026	244	8.3	399	1.0	395	14.1
2	577542	6267090	245	8.3	398	1.3	393	14.3
3	577548	6267155	244	8.2	395	1.3	390	14.3
4	577552	6267221	238	8.1	385	0.3	384	14.1
5	578849	6267625	246	8.2	397	3.2	384	14.1
6	579145	6267678	247	8.3	402	2.8	390	14.1
7	579268	6267697	246	8.5	411	5.0	391	14.7
8	579374	6267749	246	8.7	420	5.8	396	14.9
9	579423	6267824	240	8.7	420	3.5	405	13.9
10	579281	6267801	249	8.7	418	3.4	404	14.1
11	579151	6267762	247	8.4	407	2.0	398	13.7
12	578798	6267674	248	8.5	411	0.8	408	13.0

* Gross energy production includes topographic effect; "Gross energy – Wake" includes topographic effect and wake losses.

** Turbulence Intensity includes ambient turbulence and incident turbulence. The values represent true meteorological turbulence; they should not be compared directly with IEC models and consequently should not be used to establish the wind turbine class.



Legend

- Wind Turbine
- Met Mast
- Diesel generator
- Building
- Wharf
- Contour (5m)
- Road
- Watercourse
- Sand area
- Waterbody
- Woodlands

0 125 250 500 m

1:15,000

Spatial referencing UTM Zone 20 NAD83.

SOURCE :
Canvec - Natural Resource Canada 1:50 000
Action Canada Conference - Mt.Sophie viewer

NO	DESCRIPTION	BY	CHK'D	APP'D	DATE

REVISIONS

Turbine model: EWT DW52-900
Number of turbines: 2
Site capacity: 1800 KW
Turbine rated power: 900 KW
Hub height: 40 m
File reference: Nain_WF2_Lay4.txt

HATCH

DESIGNED BY
DANY AWAD
DATE: August 31, 2015

DRAWN BY
SLADJANA PAVLOVIC
DATE: August 31, 2015

CHECKED BY
Dany Awad
DATE: August 31, 2015

NALCOR

Nain - Layout 1

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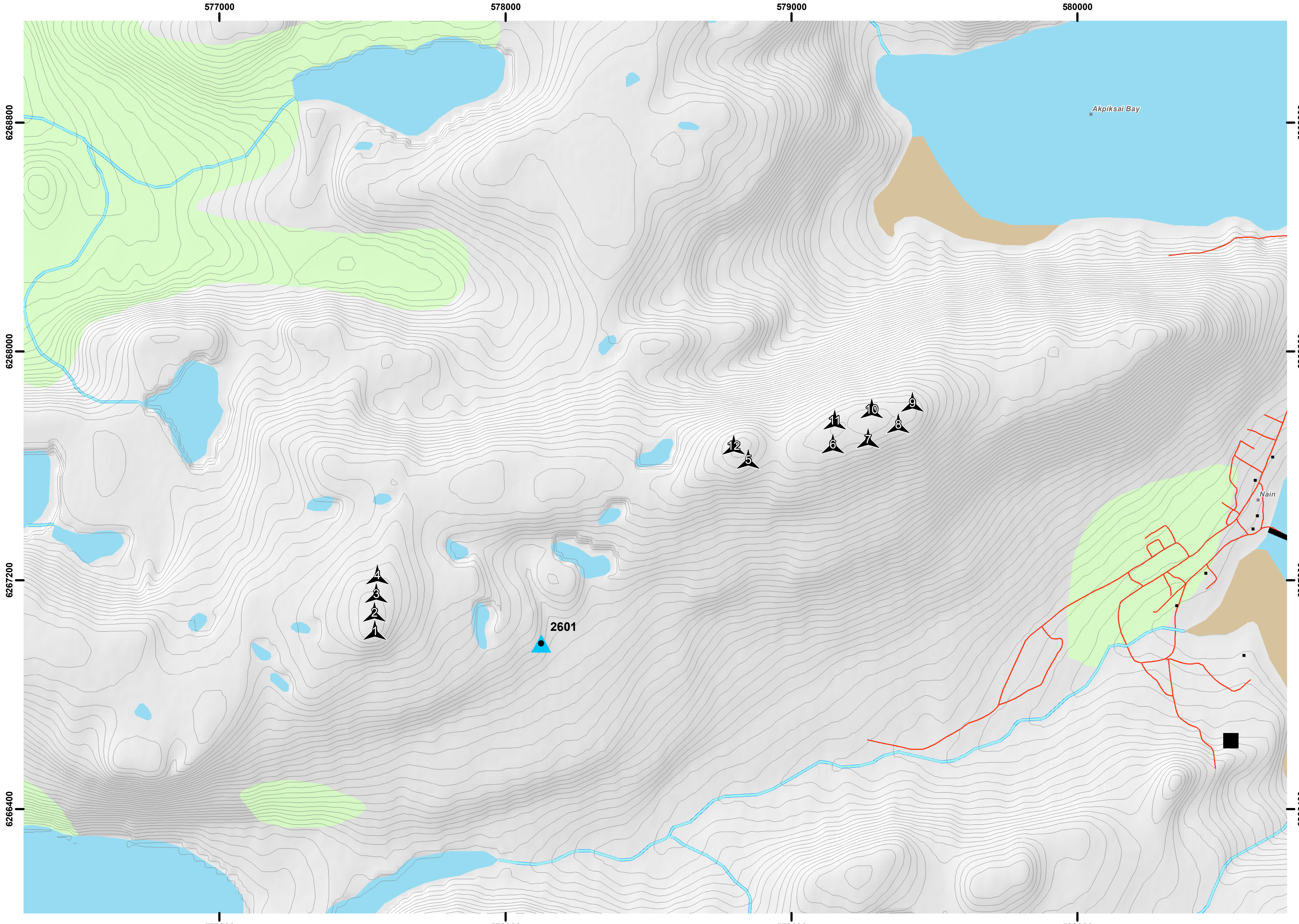
SCALE: BAR
REV. 3



Legend

- Wind Turbine
- Met Mast
- Diesel generator
- Building
- Wharf
- Contour (5m)
- Road
- Watercourse
- Sand area
- Waterbody
- Woodlands

N

0 125 250 500 m

1:15,000

Spatial referencing UTM Zone 20 NAD83.

SOURCE :
Canvec - Natural Resource Canada 1:50 000
Action Canada Conference - Mt.Sophie viewer

NO	DESCRIPTION	BY	CHK'D	APP'D	DATE

REVISIONS

Turbine model: Northern Power 100
Number of turbines: 12
Site capacity: 1200 KW
Turbine rated power: 100 KW
Hub height: 37 m
File reference: Nain_WF2_Lay5.txt

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DESIGNED BY DANY AWAD
DATE: August 31, 2015

DRAWN BY SLADJANA PAVLOVIC
DATE: August 31, 2015

CHECKED BY Dany Awad
DATE: August 31, 2015

NALCOR

Nain - Layout 2

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SCALE BAR

REV. 3

5.3.4 *Losses*

This section provides a description of the estimated losses included in the P50 estimate. These losses include environmental, electrical, availability, turbine performance losses and wake effects. The P50 is defined as the exceedance probability that denotes the level of annual wind-driven electricity generation that is forecasted to be exceeded 50% of the year. Half of the year's output is expected to surpass this level, and the other half is predicted to fall below it. Loss estimates should be reviewed as more detailed information becomes available.

The losses considered are presented in the following table and described hereafter.

Table 5-8: Wind Farm Losses

Loss Category	Loss Type	Losses (%)			
		Layout 1 - EWT900		Layout 2 - NPS100 Arctic	
Environmental	Blade Soiling and Degradation	1.0	5.2	1.0	4.7
	High Wind Hysteresis	0.2		0.2	
	Icing	3.6		3.5	
	Lightning	0.0		0.0	
	Low Temperature Shutdown	0.4		0.0	
Electrical	Collection Network	1.3	3.5	1.3	2.1
	Auxiliary power	2.2		0.8	
Availability	Wind Turbine Availability	5.0	5.8	6.5	7.3
	Collection Network Outage	0.6		0.7	
	Grid Availability	0.2		0.2	
Turbine Performance	Out-of-range Operation	1.0	1.0	1.0	
Wake effects	Internal Wake Effects	0.5	0.4	2.5	2.5
	External Wake Effects	0.0		0.0	
	Total*	**15.0**		**16.5**	

* The total is the cumulated effect of the different losses and not their direct summation

Blade soiling and Degradation refers to the reduction of the blade's aerodynamic performance due to dust and/or insects. It also takes into account the future blade degradation attributed to wear of the blade's surface. The Nain project is not situated in a particularly dusty environment. This value is consistent with what is generally observed within the industry.

High wind hysteresis losses are caused by the control loop of the turbine around cut-out wind speed. They depend on the wind turbine design.

These estimations are based on the turbines' control loop specifications and high wind hysteresis simulations. Based on the available wind distribution at the mast, the loss induced by the hysteresis loop is 0.2%.

Icing losses happen in different ways: ice accumulation on blades alter their aerodynamic performance, nacelle-mounted instruments affected by ice give inaccurate readings and induce turbine control system errors, asymmetric icing causes mass or aerodynamic imbalance leading to vibrations that may force control systems to shut down the turbine. Icing can have different impact on the production of the turbine and the effect is site-specific. Some areas will be more affected by freezing rain or glaze ice and other regions are more prone to have rime ice or in-cloud icing.

Icing losses are estimated from the detection of icing events during met masts data quality control and translating the icing events into production losses. The level of ice is considered moderate as compared to other northern sites (up to 10% of icing losses).

Values should be taken with caution since no proven methodology is available and because the effect and characteristics of ice are highly site-specific. The uncertainty associated to these aspects is taken into account in the global uncertainty assessment.

Lightning has the potential to damage the turbine control system but also the blade integrity. Modern wind turbines have protection devices that most of the time allow continuous operation even after a lightning strike. There is however, a small chance that lightning will impact turbine operation. The lightning losses were estimated according to Environment Canada maps[5].

Low temperature shutdown losses depend on the local climate, the turbine design and the control algorithm. In cold climates, turbine shutdowns can be driven by low temperature detection, even if the wind is blowing. According to the manufacturers' specifications, the wind turbines with cold weather package have an operation threshold of - 40°C. The loss is estimated based on the long-term temperature data measured at Nain Environment Canada station.

Collection network loss is considered at the interconnection point. It takes into account various elements, including the length of the cables connecting the wind turbines to the substation and the losses in the substation itself. Losses depend on the design of these elements.

These losses have been estimated by Hatch according to previous experiences with similar project size and conditions. They should be confirmed when the design of the collection network is finalized.

Auxiliary power losses account for various subsystems of a wind turbine that require electrical power, such as control systems or heaters. All of these losses are not always

[5] http://ec.gc.ca/foudre-lightning/default.asp?lang=En&n=42ADA306-1

accounted for in the power curve. For example, cold packages designed for cold climate wind turbines can require energy even when the turbine is stopped.

Based on Hatch's experience, an estimated value is used to account for the consumption of standard auxiliary systems. Specific losses have been added for the Cold Package system delivered with the wind turbines. They have been estimated by simulation according to the Cold Package specifications of the EWT900 and NPS100 wind turbines.

Wind turbine availability losses represent the percentage of time over a year that the turbine is unavailable for power production. Losses include regular maintenance time and unexpected turbine shutdowns. A given availability rate is normally guaranteed by utility-scale wind turbine manufacturers such as EWT (95%), but in the case of smaller wind turbines (NPS100), no availability warranty will be offered by the manufacturer.

Based on Hatch's experience on wind farms in similar conditions and technology for isolated sites, Hatch considers the estimate of 6.5% to be adequate for the Project with NPS100 units.

This estimation considers a standard maintenance schedule of 1 day per year per turbine, plus unscheduled repairs and delays due to site accessibility and weather conditions. This is based on information provided by the client that wind turbines will be considered as non-essential grid components and thus deficiencies will be considered as low priority, so that individual units may remain out of service for periods longer than normally considered.

Collection Network Availability: The collection network may be out of service, stopping energy delivery from the turbines to the grid. Collection network outage losses include shutdown time for scheduled maintenance and unexpected outages.

Based on the information provided by the client, the Nain based operators will manage the site and are expected to have the skills and manpower required to fix any collection system problem in a timely manner. The presence of a support team onsite has a positive impact on the availability of the collection network.

Grid availability losses depend on the utility distribution system quality and capacity. It represents the percentage of time in a year when the grid is not able to accept the energy produced by the wind turbines.

The value used assumes the wind turbines will be connected to the grid operated by NLH, which is assumed to be well maintained and operated.

Out-of-range Operation losses take into account the aspects usually not covered by the power curve warranty such as turbulence, wind shear and yaw errors. Parameters specific to the Project have been used to perform this loss estimate.

Wake Effect corresponds to the deficit in wind speed downstream of a wind turbine. Several models exist to quantify this effect in terms of induced energy losses. Hatch uses the Eddy Viscosity model which corresponds to a CFD calculation representing the development of the velocity deficit field using a solution of the Navier Stokes equations. Because of higher precision as compared to the Park model and recommendations from WindFarmer, the Eddy Viscosity model is used to assess to the wake of the Project. Wake losses are highly

dependent on the layout, especially regarding the distance between the turbine and the layout’s compactness.

One of the input in the wake losses calculation is the thrust curve provided by the turbine manufacturer for the Project turbine model under consideration.

No other wind farm currently exists in the vicinity of the project. In addition, no future wind farm that may impact the Project in terms of wake is planned. Thus, there are no additional wake losses.

6. Conclusions and Recommendations

6.1 Objectives of Analysis

The purpose of this report is to present a full wind resource assessment for the Nain site, including the estimation of the forecasted annual energy production.

6.2 Data Quality and Adjustments

The wind data recovery rates at the monitoring site, for the analysis period, exceed industry standards, with recovery rates ranging from 94.3% to 97.8% for the primary anemometers and 96.5% for the primary wind vane.

The measured data were adjusted to long-term through correlation with Environment Canada's Nain station, located 3 km away from the project area. The long-term adjustment method was applied since it was considered to be the best method for producing a representative data set for the expected life of the project.

6.3 Wind Resource

The annual average wind speed at the met mast is a result of the measurements and the long-term adjustment. These wind speeds are summarised in the table below for top anemometer and hub heights.

Table 6-1: Estimated Long-term Wind Speeds

Mast (Measurement Height)	Estimated Long-term Wind Speed at Measurement Height (m/s)	Estimated Long-term Wind Speed at Hub Height (m/s)	
		37 m	40 m
2601 (35 m)	6.5	6.7	6.7

The long-term dataset at the met mast was used to build the wind flow across the project area.

The complexity of the terrain is considered moderate and its effect on the modelled wind is not considered problematic.

6.4 Forecasted Energy Production

The preliminary turbine selection analysis specified two suitable turbine models: EWT900 and NPS100 Arctic. These models were proven to be best in class for cold and icy environments and suitable for wind-diesel generation in remote community.

The main results of the energy production modeling are summarised in the table below.

Table 6-2: Forecasted Annual Energy Production

Item	Layout 1 - EWT900	Layout 2 - NPS100 Arctic
WTG Rated Power (kW)	900	100
Number of Wind Turbines	2	12
Wind Farm Capacity (kW)	1800	1200
Annual Net Energy Production (MWh/yr)	**6,150**	**4,058**
Net Capacity Factor (P50) (%)	**39.0**	**38.6**

There remains some uncertainty regarding loss estimates, which should be reassessed as more information becomes available, particularly in relation to warranty contracts and maintenance schedules. Note that the Annual Net Energy Production represents the total forecasted energy production by the wind turbines. The effective energy production used to displace fuel will be a bit lower and vary depending on the chosen layout scenario (type and number of wind turbines), timewise power load and wind resource.

6.5 Recommendations

It should be noted that a number of additional studies and more detailed analysis will be required to refine and validate the turbine selected, the turbine position, the energy and losses.

The integration optimization report will show which turbine model is considered optimal for the Nain site based on energy cost, control capabilities and logistics and provide recommendations for further analysis and studies prior to implementation.

References

[1] International Energy Agency Programme, *Recommended practices for wind turbine testing and evaluation – Task 11: Wind Speed Measurement and Use of Cup Anemometer*, 1999

[2] National Renewable Energy Laboratory, *Wind Resource Assessment Handbook*, 1999

[3] International Electrotechnical Commission, *Wind Turbines - Part 1: Design Requirements*, IEC 61400-1, Ed. 3, 2005-08.

[4] International Electrotechnical Commission, *Wind Turbines - Part 12-1: Power performance measurements of electricity producing wind turbines*, IEC 61400-12-1, Ed. 1, 2005.

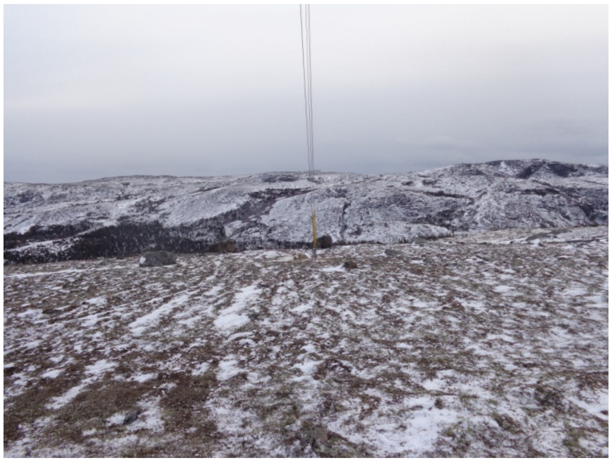
[5] A Practical Guide to Developing a Wind Project, *Wind Resource Assessment*, 2011

Appendix A

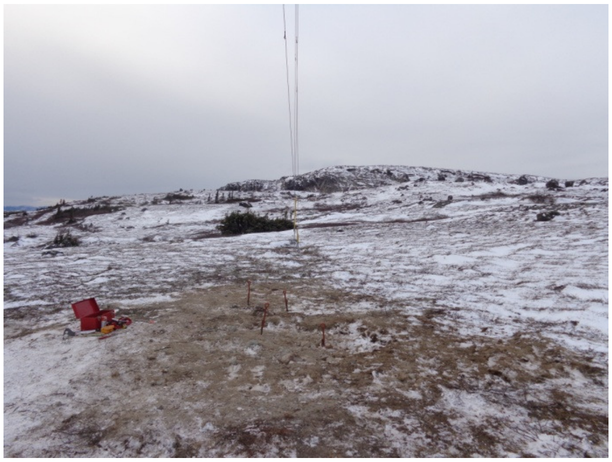
Views at Mast Site

View Facing North

View Facing East



View Facing South



View Facing West

Figure – A1: Views from Base of Mast 2601

Appendix B

Wind Turbine Data

EWT DW52-900

The power curve and the thrust curve were provided to Hatch by Emergya Wind Technologies.

Table – B1: EWT Wind Turbine Performance Curves

Rotor Diameter: 51.5 m	Hub Height: 40 m	Air Density: 1.225 kg.m^{-3}	Turbulence Intensity: N/A
Wind Speed at Hub Height (m/s)	**Electrical Power (kW)**	**Wind Speed at Hub Height (m/s)**	**Thrust Coefficients**
0	0	0	0.000
1	0	1	0.000
2	0	2	0.000
3	7	3	0.866
4	30	4	0.828
5	69	5	0.776
6	124	6	0.776
7	201	7	0.776
8	308	8	0.753
9	439	9	0.722
10	559	10	0.692
11	698	11	0.613
12	797	12	0.516
13	859	13	0.441
14	900	14	0.368
15	900	15	0.296
16	900	16	0.241
17	900	17	0.199
18	900	18	0.168
19	900	19	0.143
20	900	20	0.124
21	900	21	0.109
22	900	22	0.096
23	900	23	0.085
24	900	24	0.075
25	900	25	0.067

NPS100

The power curve and the thrust curve were provided to Hatch by Northern Power.

Table – B2: NPS100 Wind Turbine Performance Curves*

Rotor Diameter: 20.7 m	**Hub Height: 37 m**	**Air Density: 1.225 kg.m^{-3}**	**Turbulence Intensity: N/A**
Wind Speed at Hub Height (m/s)	**Electrical Power (kW)**	**Wind Speed at Hub Height (m/s)**	**Thrust Coefficients**
0	0	0	0
1	0	1	0
2	0	2	0
3	0	3	0
4	3.7	4	1.072
5	10.5	5	0.963
6	19.0	6	0.866
7	29.4	7	0.820
8	41.0	8	0.754
9	54.3	9	0.687
10	66.8	10	0.616
11	77.7	11	0.548
12	86.4	12	0.491
13	92.8	13	0.436
14	97.3	14	0.391
15	100.0	15	0.347
16	100.8	16	0.316
17	100.6	17	0.286
18	99.8	18	0.261
19	99.4	19	0.239
20	98.6	20	0.222
21	97.8	21	0.206
22	97.3	22	0.194
23	97.3	23	0.184
24	98.0	24	0.175
25	99.7	25	0.167

* Power curve of the Northern Power 100 – standard model

Dany Awad
DA:da

	Emergya Wind Technologies BV
	Engineering

Category:	Specification	Page 1 / 11
Doc code:	S-1000920	

Created by:	JT	Creation Date:	24-07-09
Checked by:	MB	Checked Date:	24-07-09
Approved by:	TY	Approved Date:	05-04-11

Title:

Specification

DIRECTWIND 52/54*900 Technical Specification

Revision	Date	Author	Approved	Description of changes
02	02-03-12	MB	TY	Format, minor text, blades, options
01	28-11-11	LE	TY	Corrections and drawings
-	-	-	-	-
-	-	-	-	-
-	-	-	-	-
-	-	-	-	-

Emergya Wind Technologies BV
Building ‘Le Soleil’ - Computerweg 1 - 3821 AA Amersfoort - The Netherlands
T +31 (0)33 454 0520 - F +31 (0)33 456 3092 - www.ewtinternational.com

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1 Introduction

This document provides a technical overview of the *DIRECTWIND* 52/54*900 Wind Turbine designed for the IEC class II/III application. It is to be read in conjunction with document S-1000921 “Directwind 52/54*900 Electrical Specification”.

2 Technical Description

The *DIRECTWIND* 52/54*900 is a direct-drive, variable speed, pitch regulated, horizontal axis, three-bladed upwind rotor wind turbine.

The gearless direct-driven synchronous generator operates at variable speed. This is made possible by an actively controlled AC-DC-AC IGBT power converter connected to the grid. Benefits of this design are low maintenance, constant power output at wind speed above rated, and relatively low structural loads compared to constant-speed stall-controlled or constant-speed pitch-controlled wind turbines.

The generator is fully integrated into the structural design of the turbine, which allows for a very compact nacelle design. The drive-train makes use of only one main bearing, whereas classic designs have separately supported main shaft, gearbox and generator. All dynamically loaded interfaces from the blades to the foundation are sturdy flange connections with machined surfaces, and high tensile steel pre-stressed bolt connections are used.

2.1 Operation and safety system

The turbine operates automatically under all wind conditions and is controlled by an industrial PLC (Programmable Logic Controller). The cut-in wind speed is approximately 3m/s. When the rotational speed reaches the cut-in threshold, the power converter begins to deliver power to the grid.

The power converter controls the generator power output and is programmed with a power set-point versus rotor speed curve. Below rated wind speed the power output is controlled to optimise rotor speed versus aerodynamic performance (optimum λ-control). Above rated wind speed the power output is kept constant at rated value by PD-controlled active blade pitching.

The dynamic responses of the drive train and power controller are optimised for high yield and negligible electrical power fluctuations. The variable speed rotor acts as a flywheel, absorbing fluctuating aerodynamic power input. The turbine controllers are located in the rotor hub and the tower base (with remote IO in the nacelle) and carry out all control functions and safety condition monitoring. In the case of a fault, or extreme weather conditions, the turbine is stopped by feathering of the blades to vane position (blades swivelled to 90^0 with respect to rotor's rotational plane). In case of power loss, an independent battery backup system in each blade ensures the blades are feathered.

In the case of less serious faults which have been resolved, or when extreme weather conditions have passed, the turbine restarts automatically to minimise downtime.

2.2 Generator

The multiple-pole, direct-drive generator is directly mounted to the hub. The stator is located in the non-moving outer ring and the wound pole, separately excited rotor rotates on the inner ring.

The generator is designed such that all aerodynamic forces are directly transferred to the nacelle construction without interfering with the generator-induced loads.

2.3 Power Converter

The power converter is an AC-DC-AC IGBT active switching converter. It controls the generator to operate in its optimum range, and maintains power quality to the grid. The inverter can produce unity power factor (cosΦ=1) to the grid under all load conditions. Power factor is also controllable within limits.

2.4 Rotor

The rotor is a three bladed construction, mounted up-wind of the tower. Rotational speed is regulated by active blade adjustment towards vane position. Blade pitch is adjusted using an electric servomotor on each of the blades.

Each blade has a complete, fully independent pitch system that is designed to be fail-safe. This construction negates the need for a mechanical rotor brake. The pitch system is the primary method of controlling the aerodynamic power input to the turbine.

At below rated wind speed the blade pitch setting is constant at optimum aerodynamic efficiency. At above rated wind speed the fast-acting control system keeps the average aerodynamic power at the rated level by keeping the rotor speed close to nominal, even in gusty winds.

The rigid rotor hub is a nodular cast iron structure mounted on the main bearing. Each rotor blade is connected to the hub using a pre-stressed ball bearing. It is sufficiently large to provide a comfortable working environment for two service technicians during maintenance of the pitch system, the three pitch bearings and the blade root from inside the structure.

2.5 Rotor blade set

The rotor blades are made of fibreglass-reinforced epoxy. The aerodynamic design represents state-of-the-art technology and is based on a pitch-regulated concept. No extenders are used and the aerodynamic design is optimal for this rotor diameter.

2.6 Main bearing

The large-diameter main bearing is a specially designed three row cylindrical roller bearing. The inner non-rotating ring is mounted to the generator stator. The outer rotating ring is mounted between the hub and generator rotor. The bearing takes axial and radial loads as well as bending moments. Entrance to the hub is through the inner-bearing ring. The bearing is greased by a fully automatic lubrication system controlled by the turbine PLC.

2.7 Nacelle

The nacelle is a compact welded construction which houses the yaw mechanism, a service hoist and a control cabinet. Both the generator and the tower are flanged to the nacelle. The geometry of the construction assures an ideal transfer of loads to the tower and, with the absence of a shaft and gearbox, results in a simple design ensuring easy personnel access.

2.8 Yaw system

The yaw bearing is an internally geared ring with a pre-stressed four point contact ball bearing. Electric planetary gear motors yaw the nacelle. The yaw brake is passive and is based on the friction of brake pads sitting directly on the bearing ring, keeping the yaw system rigid under most loading conditions.

2.9 Tower

The nacelle assembly is supported on a tubular steel tower, fully protected against corrosion. The tower allows access to the nacelle via a secure hinged access door at its base. The tower is fitted with an internal ladder with safety wire and optional climb assistance, rest platforms and lighting. Standard hub heights are 35, 40, 50 and 75 metres.

2.10 Anchor

The turbine is supported by a concrete foundation. The connection to this foundation is provided by means of a cast-in tube or rod anchor.

2.11 Control System

2.11.1 Bachmann PLC

The M1 controller perfectly combines the openness of a PC-based controller with the reliability of industrial hardware platforms. Designed to withstand the toughest ambient conditions it guarantees error-free use over long periods of time.

A modern system architecture designed for consistent network-capability permits the easy integration of the M1 into the environment of the controller and system peripherals. Real-time ethernet permits the real-time networking of the controllers, and the support of all standard Fieldbus systems permits the connection of standard external components.

2.11.2 DMS

DIRECTWIND Monitoring System – EWT's proprietary HMI featuring local monitoring and control at the turbine, integrated into a remote-access SCADA. DMS offers individual turbine control and total park monitoring and data logging from your Wind Turbine, Wind Park or internet access point.

2.12 Earthing and lightning protection

The complete earthing system of the wind turbine incorporates:

1. Protective earthing:
   A PE connection ensures that all exposed conductive surfaces are at the same electrical potential as the surface of the Earth, to avoid the risk of electrical shock if a person touches a device in which an insulation fault has occurred. It ensures that in the case of an insulation fault (a "short circuit"), a very high current flows, which will trigger an over-current protection device (fuse, circuit breaker) that disconnects the power supply.

2. Functional earthing:
   Earthing system to minimize and/or remove the source of electrical interference that can adversely affect operation of sensitive electrical and control equipment.

   A functional earth connection serves a purpose other than providing protection against electrical shock. In contrast to a protective earth connection, the functional earth connection may carry electric current during the normal operation of the turbine.

3. Lightning protection:
   To provide predictable conductive path for the over-currents in case of a lightning strike and electromagnetic induction caused by lightning strike and to minimize and/or remove dangerous situations for humans and sensitive electrical equipment.

Since the mechanical construction is made of metal (steel), all earthing systems are combined.

2.13 Options

The following options are available:
- Cold climate operation (rated for operation down to -40°C)
- Ice detection and/or prevention system
- Aviation lights
- Shadow flicker prevention
- Low Voltage Ride-through (LVRT)
- Service lift (75m tower only)
- G59 protection relay

3 Technical Data

Where data are separated by "/" this refers to the respective rotor diameter (52 / 54 m).

3.1 Wind and Site Data

Wind class	II / III according to IEC 61400 – 1
Max 50-year extreme	59.5 / 52.5 m/s
Turbulence class	A (I_{15} = 0.16)
Maximum flow inclination (terrain slope)	8°
Max ann. mean wind speed at hub height	8.5 / 7.5 m/s
Nominal air density	1.225 kg/m³

3.2 Operating Temperature

	Standard	Cold Climate
Min ambient operating	-20°C	-40°C
Max ambient operating	+40°C	+40°C

3.3 Cooling

Generator cooling	Air cooled
Converter cooling	Water or air cooled (configuration-dependent)

3.4 Operational Data

Cut in wind speed	3 m/s
Cut out wind speed	25 m/s
Rated wind speed	14 / 13.5 m/s
Rated rotor speed	26 rpm
Rotor speed range	12 to 33 rpm
Power output	900kW
Power factor	1.0 (adjustable 0.95 lagging to 0.95 leading) Measured at LV terminals

3.5 Rotor

Diameter	52 / 54 m
Type	3-Bladed, horizontal axis
Position	Up-wind
Swept area	2,083 / 2,290 m²
Power regulation	Pitch control; Rotor field excitation
Rotor tilt angle	5°

3.6 Blade Set

Type	PMC 24.5 / 25.8
Blade length	24.5 / 25.8 m
Chord at 22.0 m	0.879 m (90% of 24.5m blade radius)
Chord at 23.5 m	0.723 m (90% of 25.8m blade radius)
Chord Max at 5.5 m	2.402 m
Aerodynamic profile	DU 91, DU 98 and NACA 64618
Material	Glass reinforced epoxy
Leading edge protection	PU coating
Surface colour	Light grey RAL 7035
Twist Distribution	11.5^0 from root to 5.5m then decreases linearly to 0.29^0, then non-linearly to 0^0

3.7 Transmission System

Type	Direct drive
Couplings	Flange connections only

3.8 Controller

Type	Bachmann PLC
Remote monitoring	DIRECTWIND Monitoring System, proprietary SCADA

3.9 Pitch Control and Safety System

Type	Independent blade pitch control
Activation	Variable speed DC motor drive
Safety	Redundant electrical backup

3.10 Yaw System

Type	Active
Yaw bearing	4 point ball bearing
Yaw drive	3 x constant speed electric geared motors
Yaw brake	Passive friction brake

3.11 Tower

Type	Tapered tubular steel tower
Hub height options	HH = 35, 40, 50, 75 m
Surface colour	Interior: White RAL 9001, Exterior: Light grey RAL 7035

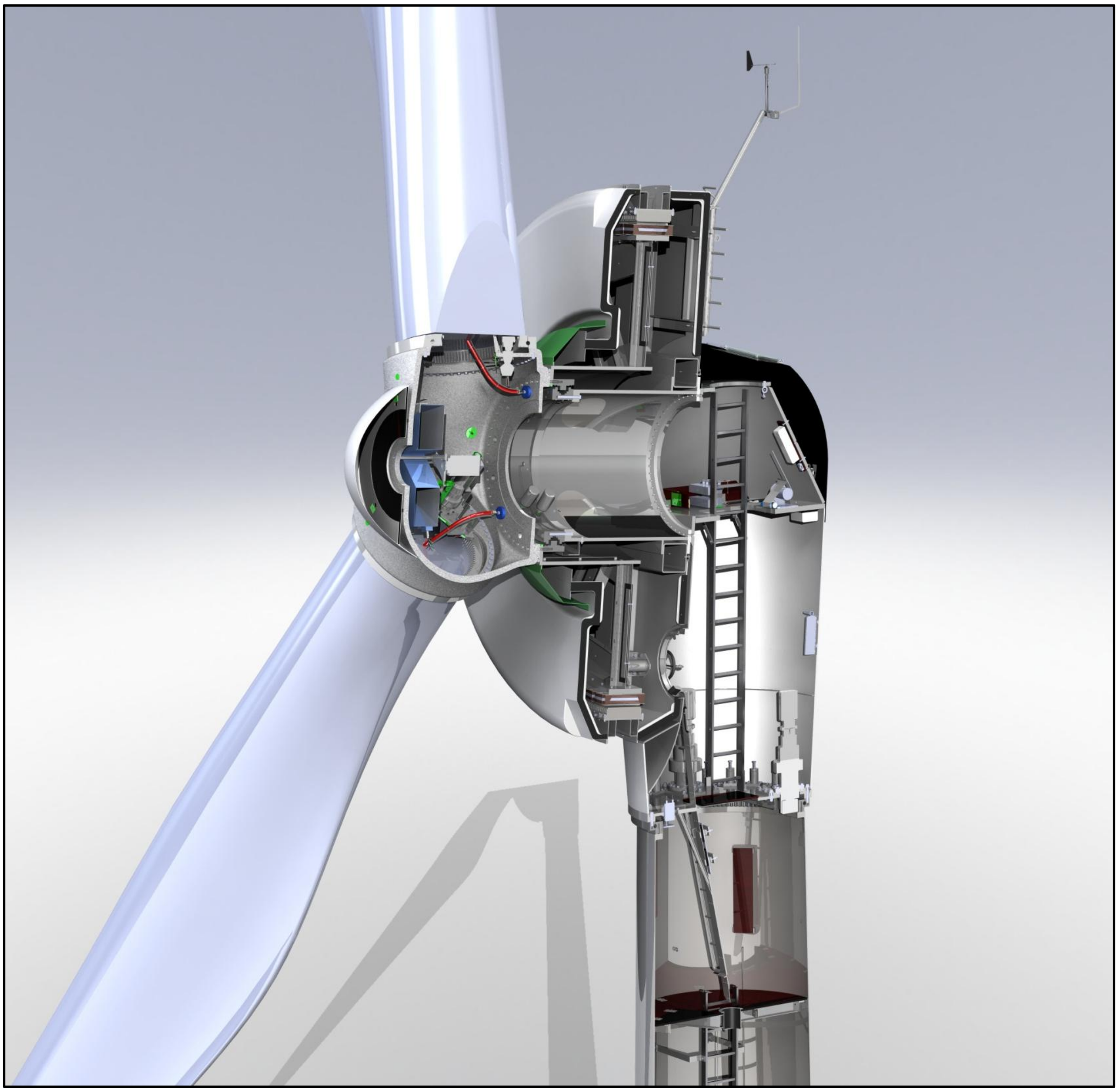
3.12 Mass Data

Hub	9,303 kg
Blade – each	1,919 / 1,931 kg
Rotor assembly	15,060 / 15,096 kg
Generator	30,000 kg
Nacelle assembly	10,000 kg
Tower HH35	28,300 kg
Tower HH40	34,000 kg
Tower HH50	46,000 kg
Tower HH75	86,500 kg

3.13 Service Brake

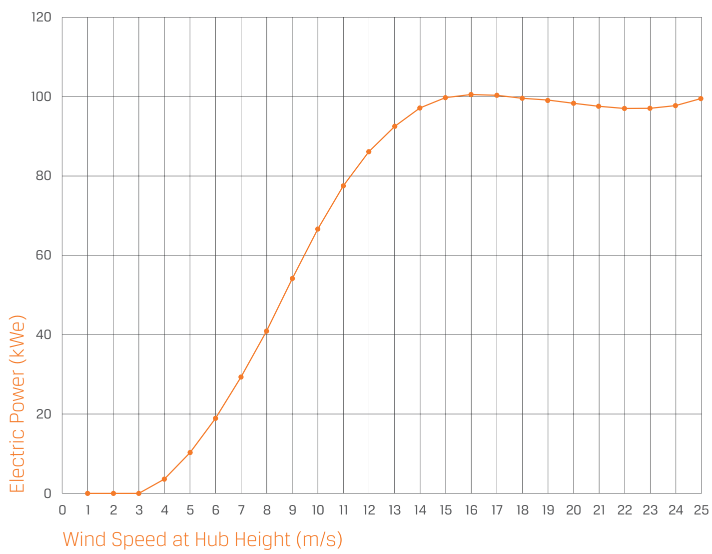
Type	Maintenance brake
Position	At hub flange
Calipers	Hydraulic 1-piece

APPENDIX 1: 3D image of main turbine components



Northern Power® 100

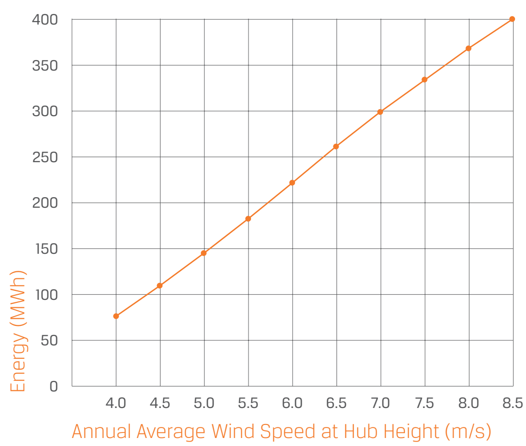
Power Curve: 21-Meter Rotor Standard Air Density (1.225 kg/m³)



Wind Speed (m/s)	Power (kWe)	Wind Speed (m/s)	Power (kWe)
1	0	14	97.3
2	0	15	100.0
3	0	16	100.8
4	3.7	17	100.6
5	10.5	18	99.8
6	19.0	19	99.4
7	29.4	20	98.6
8	41.0	21	97.8
9	54.3	22	97.3
10	66.8	23	97.3
11	77.7	24	98.0
12	86.4	25	99.7
13	92.8		

1 m/s = 2.24 mph

Annual Energy Production*: 21-Meter Rotor Standard Air Density, Rayleigh Wind Speed Distribution



Average Annual Wind Speed (mph)	Average Annual Wind Speed (m/s)	Annual Energy Output (MWh/yr)
8.9	4.0	77
10	4.5	110
11	5.0	145
12	5.5	183
13	6.0	222
15	6.5	260
16	7.0	298
17	7.5	334
18	8.0	368
19	8.5	400

*Annual energy production estimates assume standard conditions, 100% availability and no losses.

Northern
POWER SYSTEMS

Specifications

GENERAL CONFIGURATION	DESCRIPTION
Model	Northern Power® 100
Design Class	IEC IIA (air density 1.225 kg/m^3, average annual wind below 8.5 m/s, 50-yr peak gust below 59.5 m/s)
Design Life	20 years
Hub Height	37 m (121 ft) / 30 m (98 ft)
Tower Type	Tubular steel monopole
Orientation	Upwind
Rotor Diameter	21 m (69 ft)
Power Regulation	Variable speed, stall control
Certifications	UL1741, UL1004-4, CSA C22.2 No.107.1-01, CSA C22.2 No. 100.04, and CE compliant

PERFORMANCE	DESCRIPTION (standard conditions: air density of 1.225 kg/m^3, equivalent to 15°C (59°F) at sea level)
Rated Electrical Power	100 kW, 3 Phase, 480 VAC, 60/50 Hz
Rated Wind Speed	14.5 m/s (32.4 mph)
Maximum Rotation Speed	59 rpm
Cut-In Wind Speed	3.5 m/s (7.8 mph)
Cut-Out Wind Speed	25 m/s (56 mph)
Extreme Wind Speed	59.5 m/s (133 mph)

WEIGHT	DESCRIPTION
Rotor (21-meter) & Nacelle (standard)	7,200 kg (16,100 lbs)
Tower (37-meter)	13,800 kg (30,000 lbs)

DRIVE TRAIN	DESCRIPTION
Gearbox Type	No gearbox (direct drive)
Generator Type	Permanent magnet, passively cooled

BRAKING SYSTEM	DESCRIPTION
Service Brake Type	Two motor-controlled calipers
Normal Shutdown Brake	Generator dynamic brake and two motor-controlled calipers
Emergency Shutdown Brake	Generator dynamic brake and two spring-applied calipers

YAW SYSTEM	DESCRIPTION
Controls	Active, electromechanically driven with wind direction/speed sensors and automatic cable unwind

CONTROL/ELECTRICAL SYSTEM	DESCRIPTION
Controller Type	DSP-based multiprocessor embedded platform
Converter Type	Pulse-width modulated IGBT frequency converter
Monitoring System	SmartView remote monitoring system, ModBus TCP over ethernet
Power Factor	Set point adjustable between 0.9 lagging and 0.9 leading
Reactive Power	+/- 45 kVAR

NOISE	DESCRIPTION
Apparent Noise Level	55 dBA at 30 meters (98 ft)

ENVIRONMENTAL SPECIFICATIONS	DESCRIPTION
Temperature Range: Operational	-20°C to 50°C (-4°F to 122°F)
Temperature Range: Storage	-40°C to 55°C (-40°F to 131°F)
Lightning Protection	Receptors in blades, nacelle lightning rod and electrical surge protection
Icing Protection	Turbine designed in accordance with Germanischer Lloyd Wind Guidelines Edition 2003

All Specifications subject to change without notice.

NPS100SS-2222011-US

Appendix B: Wind Resource Assessment Report – Hopedale

Project Report

November 15, 2015

Newfoundland and Labrador Hydro
Hopedale Wind Project

Distribution

Trevor Andrew – NLH
Asim Haldar – NLH
Bob Moulton – NLH
Timothy Manning – NLH
Terry Gardiner – NLH
Louis Auger – Hatch
Dany Awad – Hatch
Ève-Line Brouillard – Hatch

Final Wind Resource Assessment Report

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Safety • Quality • Sustainability • Innovation

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DOCUMENT HISTORY

Revision	Date	Description
1	September 1, 2015	Final Version
2	November 15, 2015	Few edits based on comments from NLH on October 30, 2015 – Final Version

EXECUTIVE SUMMARY

In order to assess the potential of Hopedale site for wind power development, a wind resource assessment (WRA) was completed. The site is located near the community of Hopedale, Newfoundland and Labrador, Canada. The site was equipped with one met mast that is described in the table below.

Met Mast	Installation Date	Top Anemometer Height (m)	Elevation (m)	Data Collection* Starts…	Data Collection* Ends…
2602	October 27, 2013	35.0	89	October 27, 2013	April 30, 2015

* A 12 month period is selected to estimate the annual energy production

In the analysis, the quality control process demonstrated that the data recovery rates exceeded 98.6 % on main instruments (A1 and V1) which meets industry standards for wind measurement campaign. Erroneous or unreliable data were replaced with available redundant data from instruments on the same met mast since these are considered to be equivalent wind measurements.

The **wind speed** measured at the mast is **7.2 m/s** in average. The **winds are dominant from west-southwest and north-northwest** across the site.

The wind **turbulence intensity** observed at the site is generally **moderate**.

Given the land cover and topography at the mast the **wind shear exponent**, equal to **0.13**, is consistent with the expected value.

Met Mast	Period	Annual Average of Measured Wind Speed* (m/s)	Annual Average of Measured Turbulence Intensity* (%)	Annual Wind Shear
2602	December 1, 2013 to November 30, 2014	7.2	13.6	0.13

** at Top Anemometer Height*

During the data quality control process, icing events were detected on anemometers and wind vanes. **Icing** occurred **5.4% of the time** at the site. Given the site elevation and the temperatures associated with these events, it is likely that about 57% of these events were caused by freezing rain and about 43% were caused by rime ice. Icing events mainly occurred during the months of November, December and April.

Temperature data were collected at the mast. The monthly averages range from **-18.4°C** in February to **12.2°C** in August, with an **annual average** of **-3.4°C**. The coldest 10-minute temperature recording during the data collection period was -33.1°C.

The **air density** was calculated at the mast according to the elevation and the local temperature. The annual value is **1.31 kg/m^3**.

The annual average power density is **499 W/m²**. The most powerful winds come from northwest across the site.

In order to estimate the **long-term wind regime** at the site, several potential **reference stations** with historical data were selected.

The **Hopedale (AUT) station** monitored by Environment Canada, located 2 km away from the potential wind farm site, was selected as the reference station for the long-term extrapolation of the data. The reference station data were then correlated to met mast 2602 and used to translate the short-term data into long-term estimates.

The long-term estimates were then extrapolated from measurement height to hub heights.

Met Mast	Period	Estimated Long-term Wind Speed at Top Anemometer Height (m/s)	Estimated Long-term Wind Speed at Hub Height (m/s) at 37 m / 40 m
2602	December 1, 2013 to November 30, 2014	7.1	7.2 / 7.3

The wind resource estimated at the mast was used to compute the wind flow across the project area. The wind flow was calculated with WAsP 11.02.0062 software, which is an appropriate model for the Hopedale project area which exhibits a moderate terrain complexity.

This wind flow was used to optimise the layout of the potential wind farm and to estimate the energy production with WindFarmer software.

A preliminary turbine selection analysis was completed and two turbine models were selected: Emergya Wind Technologies 900 kW (EWT900) and Northern power 100 (NPS100 Arctic). These models have proven technology in cold and icy environments and are suitable for wind-diesel generation in remote community.

A wind farm layout optimisation was completed taking in consideration energy production, information from the preliminary environmental screening and turbine extreme operating condition.

The main results of the energy production modeling are presented below. Additional losses include blade soiling, icing, collection network losses, auxiliary power consumption, wind turbines availability, high wind hysteresis, low temperature shutdown, collection network outage and grid availability.

Layout	Wind Farm Capacity (kW)	Net Energy Production (MWh/year)	Net Capacity Factor (%)	Wake Losses (%)	Additional Losses (%)
Layout 1 - EWT900	900	3,398	43.1	0.0	14.0
Layout 2 - NPS100 Arctic	800	2,765	39.4	2.2	13.8

Other energy production scenarios will be covered under separate portion of the wind penetration report.

1. Introduction

Hatch has been mandated by Newfoundland and Labrador Hydro (NLH) to carry out a wind resource assessment (WRA) for a potential wind farm project, located 1 kilometre west of the community of Hopedale, Newfoundland and Labrador, Canada.

The site was instrumented with one meteorological ("met") mast. The installation was completed on October 27, 2013. The mast was equipped with sensors at several heights to measure wind speed, wind direction and temperature. The analysed data cover a total measurement period of one year.

The second section of this report presents an overview of the site and the measurement campaign.

The third section presents the main characteristics of the wind climate.

The fourth section details the process used to translate the measured short-term data into long-term data.

The fifth section presents the methodology used to obtain the wind flow map over the project area. The wind flow map optimises the wind farm layout and helps determine monthly and annual energy production estimates. The key resulting values of these estimations are provided, including a description of the losses considered in the net energy calculation.

2. General Information

This section summarises general information about the site, the meteorological (met) mast installed and the measurement campaign.

2.1 Site Description

2.1.1 Site Overview

The community of Hopedale is located in an inlet on the Labrador east coast, approximately 240 km north of Happy Valley-Goose Bay. The surroundings of the met tower consists mainly of bare rock hills with an average elevation of 100 m above sea level.

Figure 2-1: Typical Landscape at the Hopedale Area

2.1.2 Mast Location

The location of met mast 2602 was chosen with agreement between Hatch and NLH. Hatch proceeded with the installation of the mast and followed industry standards [1].

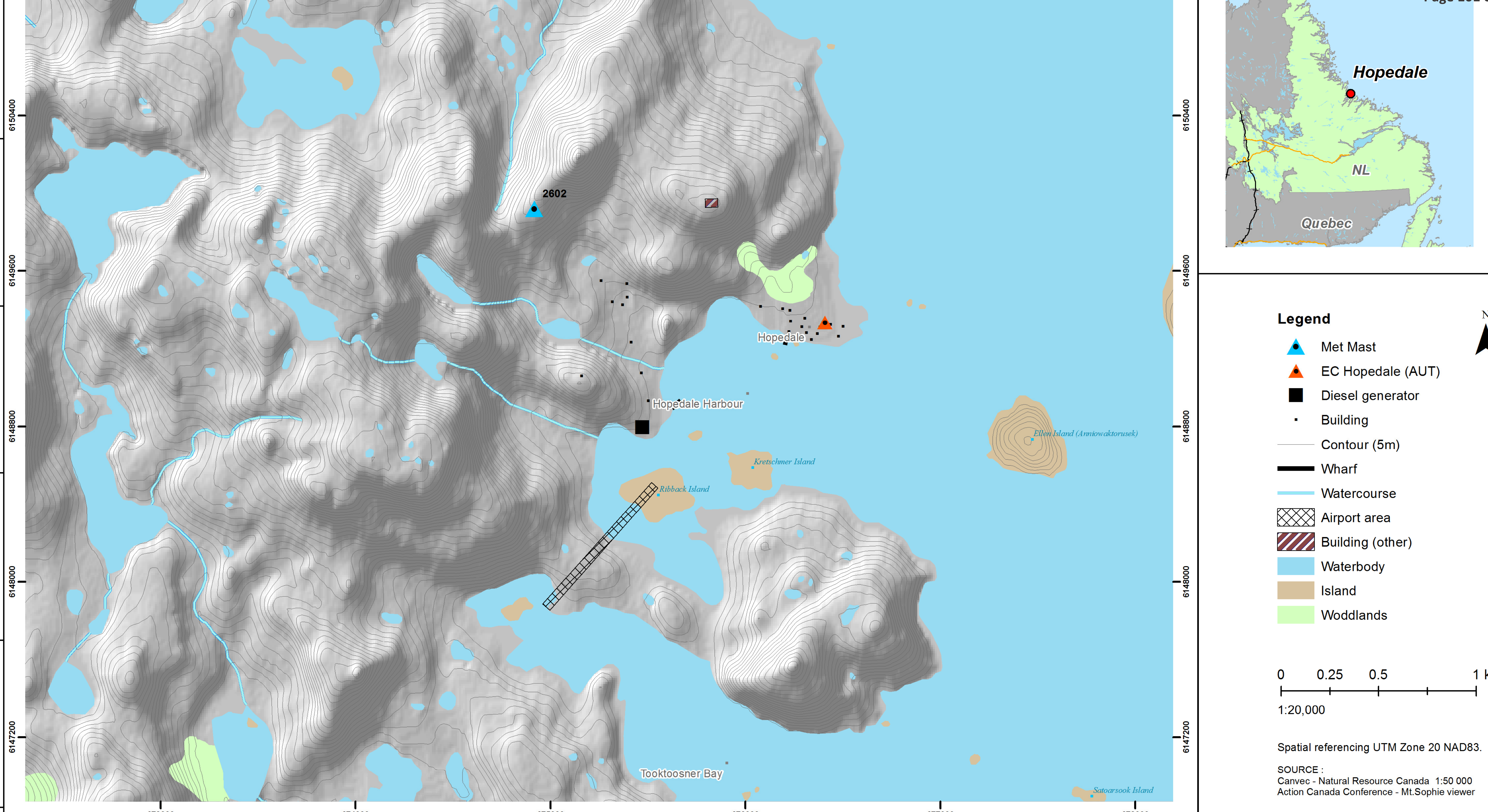
Table 2-1 provides a description of the mast, including the exact coordinates and the elevation.

The location of the mast is shown on the map provided on next page.

Table 2-1: Met Mast Characteristics (Coordinate System: NAD83)

ID	Type	Diameter (m)	Height (m)	Latitude	Longitude	Elevation (m)
2602	Square Lattice	0.404	36	N 55° 27' 50.80"	W 60° 13' 59.40"	89

Pictures have been provided in Appendix A with views in the four main geographical directions at the met mast.



NO.	DESCRIPTION	BY	CHK'D	APP'D	DATE

REVISIONS

HATCH

DESIGNED BY
SLADJANA PAVLOVIC
DATE: March 10, 2015

DRAWN BY
SLADJANA PAVLOVIC
DATE: March 10, 2015

CHECKED BY
Patrice Menard
DATE: March 10, 2015

NALCOR

Hopedale - Overview Map

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2.2 Measurement Campaigns

The mast characteristics, instrumentation, installation dates and periods of data collection are provided in this section.

2.2.1 Installation and Collection Dates

The following table provides the date of mast installation and the period of data collection used in the analysis.

Table 2-2: Installation Date and Period of Relevant Data Collection

ID	Installation date	Date and time of first data used	Date and time of last data used
2602	October 27, 2013	December 01, 2013, 00:00	November 30, 2014, 23:50

2.2.2 Instrumentation

2.2.2.1 Sensors Mounting

The met mast was equipped with anemometers and wind vanes mounted on booms at several heights. The dimensions of the booms, their heights and orientations on the mast, were designed to comply with the best practices in wind resource assessment as specified in [1] and [2].

For the met mast, the instrument and installation parameters are provided in the table below. All instruments and met mast underwent regular maintenance checks.

Heated anemometers and wind vanes were installed to increase the data recovery rate during icing periods. An Autonomous Power System (A.P.S.) developed by Hatch was installed to power supply the heating instruments. The A.P.S. consists of a set of batteries charged by a small wind turbine through a controller.

Table 2-3: Installation Parameters of Instruments at the Met Mast

Channel	ID	Height (m)	Type	Date Installed	Date Uninstalled	Calibrated / Heated	Primary / Redundant
Mast 2602							
Data Acquisition System							
N/A	N/A	N/A	NRG Symphonie PLUS3	Oct 27, 2013	July 23, 2015	N/A	N/A
Anemometers							
#1	**A1**	**35.0**	**NRG #40C**	**Oct 27, 2013**	**July 23, 2015**	**Yes/No**	**P**
#2	A2	35.0	NRG Icefree III	Oct 27, 2013	July 23, 2015	Yes/Yes	R
#3	A3	26.0	NRG #40C	Oct 27, 2013	July 23, 2015	Yes/No	P

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Channel	ID	Height (m)	Type	Date Installed	Date Uninstalled	Calibrated / Heated	Primary / Redundant
#4	A5	26.0	RMYoung 5103-AP	Oct 27, 2013	July 23, 2015	Yes/No	R
#13	A4	17.0	NRG #40C	Oct 27, 2013	July 23, 2015	Yes/No	P
Wind Vanes							
#7	**V1**	**33.0**	**NRG Icefree III**	**Oct 27, 2013**	**July 23, 2015**	**No/Yes**	**P**
#8	V2	26.0	RMYoung 5103-AP	Oct 27, 2013	July 23, 2015	No/No	R
#9	V3	15.0	NRG #200P	Oct 27, 2013	July 23, 2015	No/No	R
Temperature Sensor							
#10	T	34.0	NRG #110S	Oct 27, 2013	July 23, 2015	No/No	P

Note: Lines in bold font correspond to the anemometer and wind vane considered as the principal instruments for wind characterisation at the mast location.

2.2.2.2 Data Acquisition System

For met mast 2602, the instruments were connected to a data acquisition system which stored the data on a memory card. The data were then sent to Hatch computer network by a satellite communication system every 3 days.

3. Meteorological Data Analysis

This section presents a comprehensive analysis of the data collected. In the first section, the quality of the data is reviewed. The characteristics of the wind measured at the mast are then presented in Section 3.2 through a number of relevant parameters:

- monthly and annual average wind speeds;
- wind speed distribution;
- wind direction distribution;
- wind shear;
- turbulence intensity;
- 50-year recurrence wind speed.

In the final section, other climatic information such as measured temperature, calculated air density, wind power density and icing events is presented and discussed.

3.1 Quality Control

The quality and completeness of the data are key factors that determine the reliability of the wind resource assessment.

Data are collected periodically from the met masts and the quality of the data is analysed. This is done by applying a variety of logical and statistical tests, observing the concurrent readings from different instruments and relating these observations to the physical conditions at the site (e.g. wind shading, freezing potential, etc.). The process is semi-automated: the tests are implemented in a computer program developed by Hatch, but the expertise of quality analysts are required to accept, reject or replace data. There are many possible causes of erroneous data: faulty or damaged sensors, loose wire connections, broken wires, data logger malfunction, damaged mounting hardware, sensor calibration drift, icing events and different causes of shading (e.g. shading from the mast or from any obstacles at the site). A list of the possible error categories used during quality control is presented in Table 3-1. Data points that are deemed erroneous or unreliable are replaced by redundant data when available, or removed from the data set.

The data recovery rate for the analysis period is then calculated for each of the instruments using the following equation:

$$\text{Data recovery rate}\,(\%) = \frac{\text{Number of valid observations}}{\text{Number of potential observations}} * 100$$

The "Number of valid observations" is evaluated once erroneous or unreliable data are replaced with available redundant data. The "Number of potential observations" is the theoretical maximum number of measurements that could be recorded during the analysis period. A high data recovery rate ensures that the set of data available is representative of the wind resource over the measurement period.

Table 3-1: Quality Control Table

Error Categories
Unknown event
Icing or wet snow event
Static voltage discharge
Wind shading from tower
Wind shading from building
Wind vane deadband
Operator error
Equipment malfunction
Equipment service
Missing data (no value possible)

3.1.1 Data Replacement Policy

Erroneous or unreliable data were replaced with available redundant data from instruments on the same met mast since these are considered to be equivalent wind measurements. Replacements were done directly or by using a linear regression equation. Direct replacement is applied to anemometers when the replaced and replacing instruments are of the same model, calibrated, at the same height, and well correlated. Direct replacement is also applied to wind vanes as long as they are well correlated.

An acceptable percentage of the dataset is replaced by equivalent instruments (e.g. A1-A2: 10% of replacement) and it is considered to have a small impact on the uncertainty of the measurements.

3.1.2 Recovery Rates

The following table presents the recovery rates calculated for each instrument after quality control and after replacements have been completed according to the replacement policy.

Table 3-2: Instruments Data Recovery Rates

Mast ID	A1	A3	A4	V1	T
2602	98.6%	98.1%	85.1%	97.4%	100.0%

Note that the recovery rates for the following instruments are identical, given the replacement policy:

- A1 and A2; A3 and A5
- V1, V2 and V3

3.1.3 Data History

The data recovery rates exceed industry standards [5] except for A4. A number of data were affected for short periods of time by usual effects, such as shading effect and short period of icing events, and were removed. An occasional interruption in the signal continuity for A4 has been encountered during the period of measurement which decreases its recovery rate.

3.2 Wind Characteristics

3.2.1 Annual and Monthly Wind Speed

The monthly wind speeds measured at each anemometer are shown in the following figures for mast 2602. The data are presented in two formats (see Figure 3-1 and Figure 3-2):

a) for all instruments, the averaged monthly wind speed measured;
b) for A1, all monthly wind speeds are also reported.

Although the results for anemometers A2 and A5 are presented, they will not be considered in further calculations as these sensors were used primarily for quality control and replacement purposes.

As expected, the data confirm that wind speeds increase with height above ground level (see section 3.2.4 for a description of wind shear). Furthermore, the graphs show the seasonal pattern of wind, which decreases towards summer months and increases towards winter months.

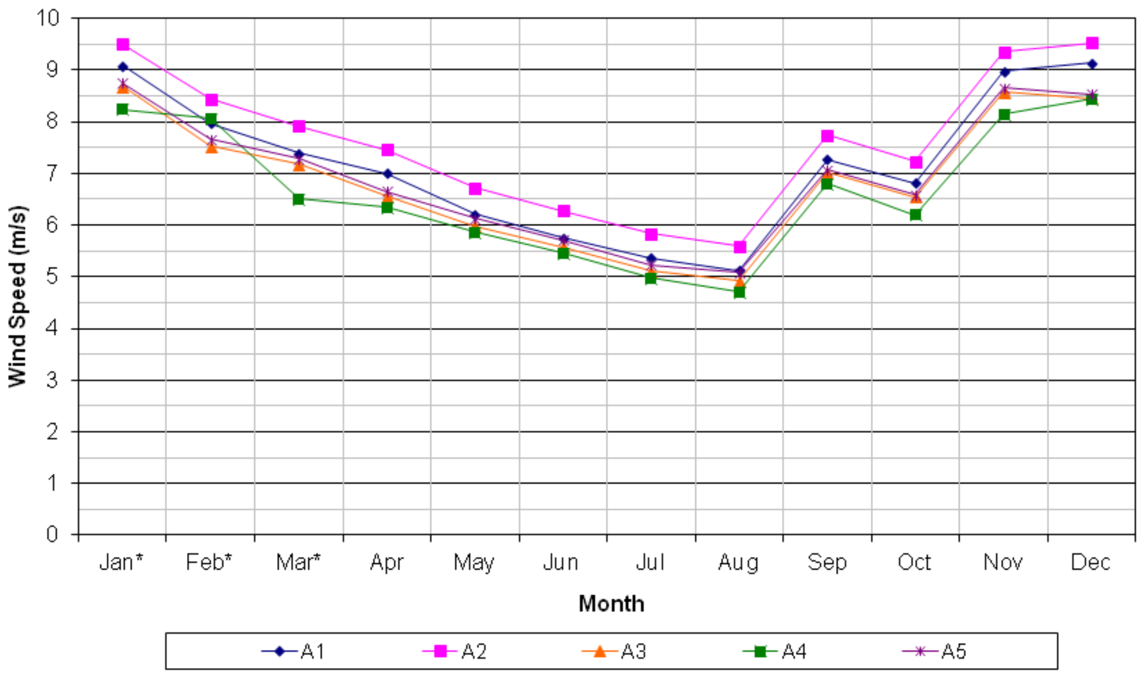


Figure 3-1: Averaged Monthly Wind Speeds for Each Anemometer at Mast 2602, December 01, 2013 to November 30, 2014

* Low recovery rates for A4 recorded in: January, February and March 2014

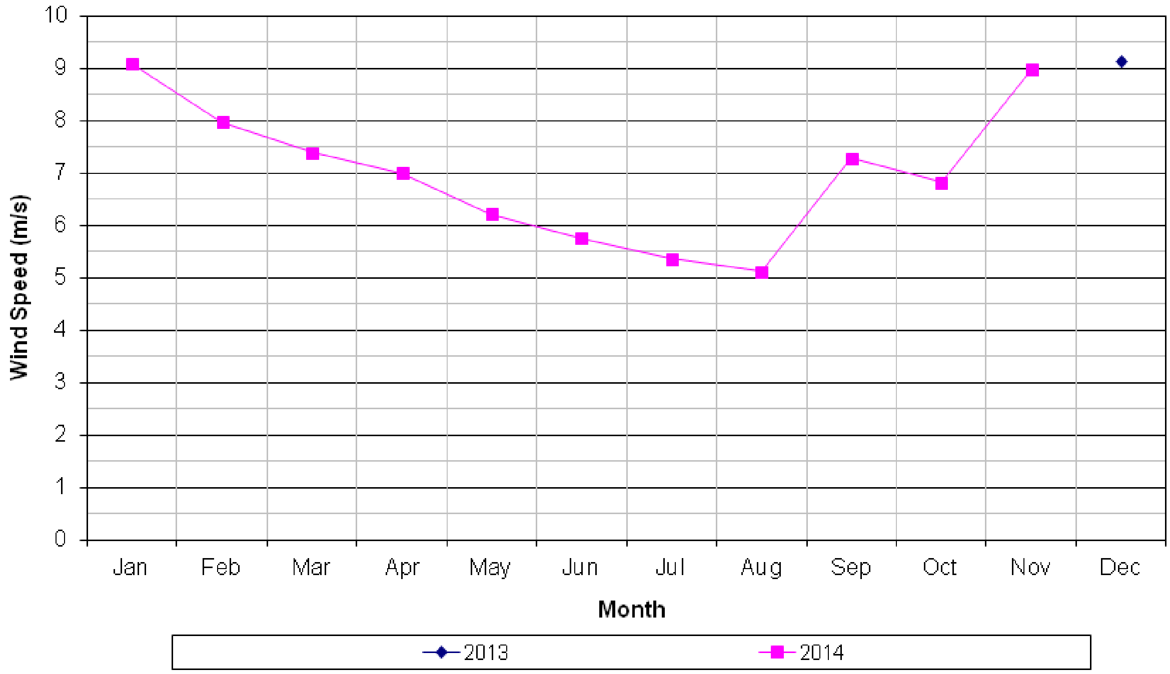


Figure 3-2: Monthly Wind Speeds Measured at the Top Anemometer at Mast 2602, December 01, 2013 to November 30, 2014

The following table provides, the average wind speed and the maximum 1-second gust observed, and specifies the averaging method used and the period of data considered. The averaging method varies as it depends upon the available dataset:

- Annual: average of the wind speed recorded over one or more full years.
- Annualised: the annualised wind speed is a weighted wind speed that is calculated from all available monthly average wind speeds–e.g. if 2 values are available for January and only one is available for February, the February value will have twice the weight of each January value in the final average.
- Average: due to insufficient data collection, the annual average wind speed was not calculated. The value given is the average of all available data.

Table 3-3: Wind Speed Characteristics at the Mast

Mast	Top Anemometer Height (m)	Period	Average Wind Speed (m/s)	Maximum 1-second gust (m/s)	Method
2602	35.0	December 01, 2013 to November 30, 2014	7.2	33.34	Annual

3.2.2 Wind Speed Frequency Distribution

The frequency distribution of wind speeds helps to evaluate how much power is contained in the wind (power is proportional to the cube of the wind speed). Wind turbines will produce more power as the wind speed increases (until reaching the "rated" value). Thus, as the frequency of higher wind speeds increases, more power can be produced.

Annual frequency distributions generally exhibit a Weibull shape that is controlled by its "scale factor" (closely linked to the average wind speed) and its shape factor.

The wind speed frequency distribution graph is presented below for the mast[1].

2602, anemometer A1, December 1, 2013 to November 30, 2014

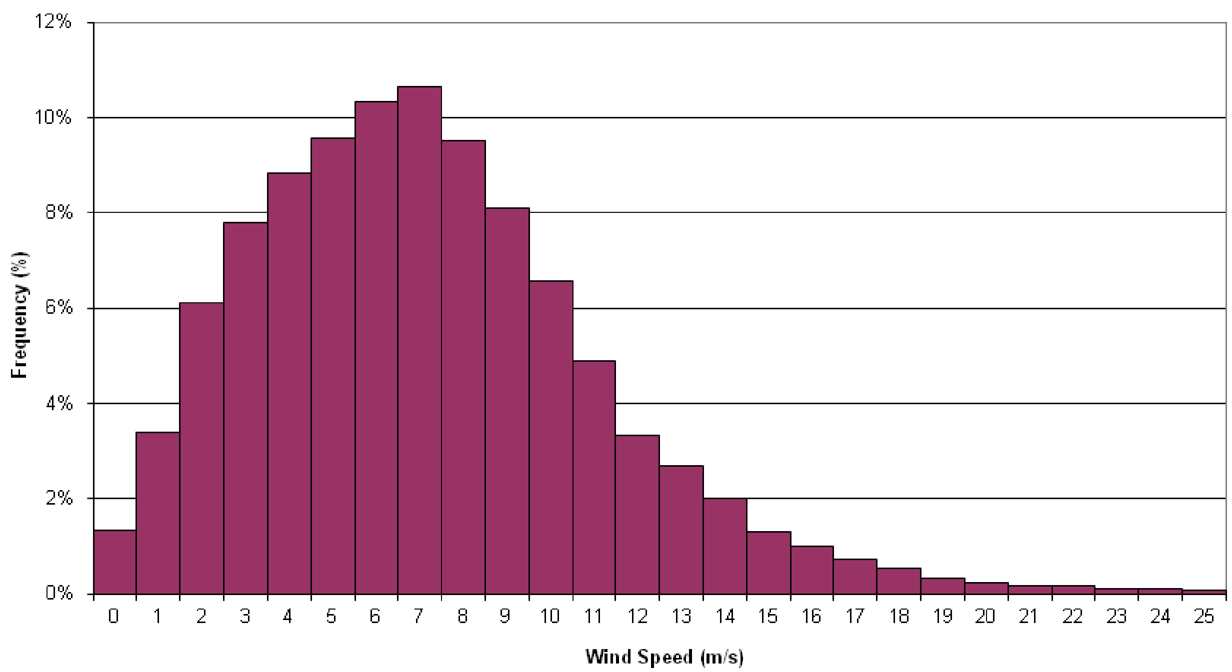


Figure 3-3: Wind Speed Frequency Distribution Graph

3.2.3 Wind Rose

The wind rose graph is presented below. The wind rose is divided into the conventional 16 compass sectors (22.5º wide sectors). Note that all compass orientations referenced in this report are based on the true geographic north, rather than the magnetic north.

[1] The 0 m/s wind speed bin indicates the fraction of the total number of measurements with a wind speed between 0 to 0.5 m/s. The other bins are 1 m/s wide and centered on the integer value (e.g.: the 1 m/s wind speed bin indicates the fraction with a wind speed between 0.5 to 1.5 m/s).

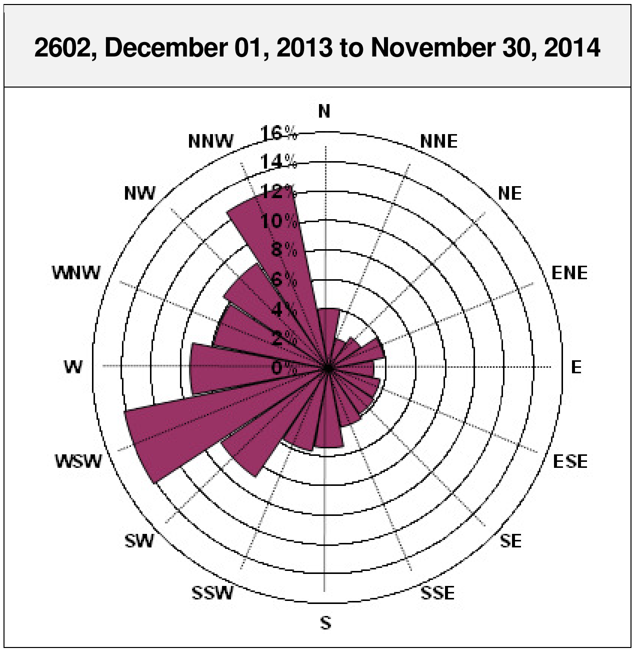


Figure 3-4: Wind Rose Graph

The wind rose indicates that a significant proportion of the wind blows from west-southwest, and north-northwest, across the project area.

Note that wind roses are not adjusted to the long-term. Moreover, differences in wind directions between the levels of measurement are small enough to be neglected. As a consequence, the present wind rose will be considered as representative of the long-term wind rose at hub height.

3.2.4 Wind Shear

Wind speeds typically increase with height above the ground, because the frictional drag decreases with altitude. The increase in wind speed with height is referred to as wind shear and is commonly modeled either by a logarithmic law or by a power law.

When the power law is used, the wind shear can be quantified by a wind shear exponent. "Rough" surfaces, such as forested lands and urban areas, have a more pronounced frictional drag than "smooth" surfaces, such as a snow covered field or grasslands–the former will be associated with higher wind shear exponents. Over a smooth, level, grass-covered terrain, the wind shear exponent is typically around 0.14; over snow or calm sea it may be as low as 0.10; and over urban areas or tall buildings it may be as high as 0.40.

The roughness is not the only surface property that has a direct effect on the wind shear. When there is dense vegetation, the vertical wind speed profile is displaced vertically above the canopy, thereby displacing the level of zero wind speed to a certain fraction of the vegetation height above the ground. The "displacement height" is defined as the height at which the zero wind speed level is displaced above the ground. The displacement height is taken into account in all wind shear estimations.

Finally, large topographic variations over short distances may also impact the wind vertical profile and thus affect the wind shear.

Hatch recommends using the log law to estimate the wind shear at mast locations. Internal studies have shown that the accuracy of the wind shear estimate is slightly improved with the log law when compared to the power law. When available, three wind speed measurements, each at a different height, are used and a log law curve is fitted through the average wind speeds at these heights. With the log law, the parameter that reflects roughness is called the roughness length, instead of the wind shear exponent. However, an equivalent wind shear exponent is calculated between the top anemometer height on a mast and the hub height for easier interpretation.

The equivalent wind shear exponent presented in this report was calculated between the top anemometer height of the mast and hub heights of 37 m and 40 m. The calculation was based on the measured wind speed at the anemometer height and the wind speed extrapolated to hub height by the log law method. The log law parameters were determined by fitting a logarithmic curve through the average measured wind speeds at the three measurement heights.

The average equivalent wind shear exponents are reported in the following table.

Based on our knowledge about the vegetation in the area of the mast, this value conforms to expected results.

Table 3-4: Average Wind Shear at the Mast

Mast	Period	Wind Shear
2602	December 01, 2013 to November 30, 2014	0.13

3.2.5 *Turbulence Intensity*

Turbulence characterises the gustiness of wind or high frequency changes in wind speed and direction (high turbulence is typical of very irregular wind flows, contaminated by whirls or vortices). Turbulence increases in areas with very uneven terrain and behind obstacles, such as buildings. In wind farms, it interferes with the effective operation of the wind turbines and increases their wear and tear.

The measurement of turbulence is expressed in terms of turbulence intensity, which is the standard deviation of the wind speed divided by the mean wind speed, over a given period. Turbulence intensity is expressed as a percentage. In the present study, the standard deviation and mean speed values are calculated from 1 second wind speed data averaged over a 10 minute period.

Turbulence intensity is more erratic and more difficult to quantify at low wind speeds. As a consequence, only wind speeds in excess of 4 m/s are used to calculate of the turbulence intensity. This threshold is consistent with IEC standards for wind turbine power performance measurements [4].

The turbulence intensity value was calculated with the top anemometer data. The average turbulence intensity is reported in the next table. This value is considered moderate according to the reference values defined in reference [2][2]. It is expected that turbulence will decrease with height, as the effect of obstacles and surface roughness will diminish. A moderate value of turbulence can also be observed in the main wind directions (WSW and NNW).

Table 3-5: Average Turbulence Intensity at the Mast

Mast	Anemometer used	Period	Turbulence Intensity (%)
2602	A1	December 01, 2013 to November 30, 2014	13.6

3.2.6 *50-year recurrence wind speed*

The selected wind turbines Northern power 100 (NPS100) and Emergya Wind Technologies 900 kW (EWT900) are designed to survive a certain level of loading caused by an extreme wind event. Based on the specification provided by the manufacturers, the extreme survival wind speed at hub height is 59.5 m/s (see Appendix B).

At least 7 years of data at the met mast location or a nearby reference station are required. The Gumbel distribution was used to predict the once-in-fifty-year extreme wind speed. The data were extrapolated to hub heights of 37 m (NPS100) and 40 m (EWT900) with a power law exponent of 0.11 suggested for gusts as per Wind Energy Handbook [2] and IEC 61400-1 standard.

In the case of Hopedale project, the met mast has only 18 months of data. Thus, data from Hopedale (AUT) Environment Canada station were used and based on hourly data at 10 metres height. The data cover the period from 2005 to 2014. The 50-year recurrence maximum wind speed was estimated to be 48.3 m/s at 37 m and 48.7 m/s at 40 m which respect the turbines' specifications.

3.3 Other Climatic Data

3.3.1 *Temperature*

Temperature was measured at a height of 34 m. The following table presents the average monthly and annual temperature measured. The coldest 10-minute temperature recording measured during the data collection period was -33.1°C in the morning of January 2, 2015.

Table 3-6: Average Monthly and Annual Temperatures

Mast ID	Monthly Air Temperature (°C)												Annual
	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	
2602	-16.8	-18.4	-15.6	-6.2	-0.1	7.2	11.0	12.2	6.2	3.3	-6.8	-17.8	-3.4

[2] Low levels of turbulence intensity are defined as values less than or equal to 0.10, moderate levels are between 0.10 and 0.25, and high levels are greater than 0.25. This classification is for meteorological turbulence only; it should not be used in comparison with IEC models. Meteorological turbulence should not be used to establish the wind turbine class.

3.3.2 Air Density

Wind energy is directly proportional to the air density. Consequently, the amount of energy produced by a wind turbine will also be directly proportional to the air density at the turbine location. Air density decreases with increasing temperature, decreasing pressure and increasing altitude.

Based on the measured temperatures and the standard barometric pressure of 101.3 kPa at sea level, the monthly average air densities were calculated. Note that to correct for changes in atmospheric pressure with height, the calculations account for the site elevation. The values were calculated over the entire analysis period reported in Table 2-2.

Table 3-7: Monthly and Annual Average Air Density

Mast ID	Monthly Air Density (kg/m^3)												Annual
	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	
2602	1.35	1.36	1.35	1.30	1.27	1.24	1.22	1.22	1.25	1.26	1.30	1.36	1.31

3.3.3 Power density

Wind speed, wind direction and air density data can be combined to provide information about the average power density at mast location. Wind power density indicates how much energy is available at a given instant for conversion by a wind turbine[3]. For example, strong winds in the winter, when the air is colder and denser, will have a higher power density (i.e. carry more energy) than the same strong winds in the summer. Though power is an instantaneous value, it is calculated as an average over a given period of time.

Tables of the power density distribution per direction and per month were produced at the top anemometer height and are presented below.

At mast 2602, the most powerful winds come from northwest, and appear in winter months. The annual average power density is 499 W/m^2 at 35.0 m.

Table 3-8: Table of Wind Power Density per Direction, December 1, 2013 to November 30, 2014

Wind Power Density per Direction (W/m^2)															
N	NNE	NE	ENE	E	ESE	SE	SSE	S	SSW	SW	WSW	W	WNW	NW	NNW
522	169	118	218	363	476	113	117	235	308	327	643	505	543	1069	721

Table 3-9: Table of Wind Power Density per Month, December 1, 2013 to November 30, 2014

Wind Power Density per Month (W/m^2)												Annual Average
Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	
883	700	701	451	291	272	225	173	496	356	808	744	499

[3] Note that the units “W/m^2” refer to m^2 of rotor swept area.

3.3.4 Icing Events

Icing affects the operation of wind turbines. Icing on any exposed part of the turbine can occur in the form of wet snow (generally associated with temperatures between 0°C to 1°C), super-cooled rain or drizzle (that can occur at temperatures between 0°C to -8°C, but mostly in the upper part of this range), or in-cloud icing (that can occur below - 2°C). Losses during production due to ice occur in several ways:

- Ice accumulation on the blades alters their aerodynamic profile, reducing the power output.

- Nacelle-mounted instruments accumulate ice and give inaccurate readings. The turbine control system may detect a fault condition due to the turbine output being much greater than expected. This expectation is based on the wind speed. As a result, the turbine will be shut down until the ice is removed from the instruments and the turbine is reset.

- Asymmetric icing causes mass or aerodynamic imbalance leading to vibrations. Control systems that sense vibrations will normally shut down when these vibrations occur.

Icing is a complex phenomenon and predicting icing from meteorological conditions is notoriously difficult, requires a good set of observations from a number of meteorology variables, and can be misleading. As no reliable instrument is presently available to detect and quantify icing events for the purpose of estimating their impact on wind energy production, Hatch uses several tests during data quality control to detect icing events: detection of unusual standard deviations or changes with time of wind speeds and directions, comparison of measurements from a heated anemometer and a standard anemometer at the same level, in parallel with the measurement of temperature.

These tests cannot distinguish between the different types of icing, but a rough approximation can be done by utilising the temperature ranges measured during icing events. Therefore, in the following estimate, we will consider two categories: "glaze", which is assumed to include wet snow, super-cooled rain and drizzle, and "rime ice", which is assumed to include in-cloud icing and the very low temperature part of super-cooled rain or drizzle. The threshold of -5°C is used to differentiate between rime ice (below -5°C) and glaze (above -5°C).

The following table presents the estimated number of icing events in a month and the type of event assumed to occur in the project area. This estimate is based on the average of icing events detected on the mast during the measurement campaign.

Table 3-10: Estimated Hours of Icing Events, October 27, 2013 to April 30, 2015

	January	February	March	April	May	June	
Hours	37	49	8	83	24	5	
Rime	100%	100%	10%	10%	0%	0%	
Glaze	0%	0%	90%	90%	100%	100%	
	July	**August**	**September**	**October**	**November**	**December**	**Annual**
Hours	0	0	0	13	139	113	470
Rime	-	-	-	0%	10%	80%	43%
Glaze	-	-	-	100%	90%	20%	57%

4. Long-term Wind Speed at Hub Height

The previous section presented the analysis of the wind regime as it was measured by the met mast installed on the project site. However, to forecast the energy production of a wind power plant, wind data that represent the historical wind conditions at the site are required. Unfortunately, wind resource assessments are generally conducted for a limited number of years, often no more than one or two years, which is not sufficient to capture the year-to-year variability of wind. For example, in North America, the annual average wind speed exhibits a standard deviation of about 6% (or 1σ from a normal distribution) of the long-term average wind speed. Hence, the maximum deviation from the average wind speeds could reach as much as 20% (or 3.3σ). Consequently, it is necessary to translate the measured short term data into long-term data. This is done through a correlation/adjustment process that makes reference to a meteorological station where historical data are available.

Moreover, when the top anemometers of the met masts are mounted at a lower height than the expected hub height of the wind turbines, the long-term data must also be extrapolated from these anemometer heights to the wind turbine's hub height.

The long-term projection process is presented in the next section and is followed by the extrapolation to hub height.

4.1 Long-term Projection

When required, selecting a reference dataset to perform a long-term correlation and adjustment is determined by the following process:

- A quality assessment of the potential long-term reference stations for the site (history, similarity of the local climate with regards to the meteorology mast climate, etc.);

- A quality assessment of the correlation equations obtained with acceptable long-term reference stations and the measured data for the concurrent period;

- A comparison of the long-term correlation results obtained with all acceptable reference stations;

- A crosscheck of the resulting long-term adjustments with the measured data and the long-term trends at nearby reference stations or at a regional level.

Once the reference dataset is selected, it is used to adjust the met mast data to long-term conditions. This can be achieved either by synthesizing non existing years of data at the met mast site or by applying an adjustment factor to the measured data in order to better reflect the reference period. The process is as follows:

- The measured data from the met mast are correlated with the reference dataset;

- If the correlation parameters meet the synthesis criteria, then data are synthesized at the measurement mast for the complete reference data period; this method is referred to as the Measure-Correlate-Predict (MCP);

- If the criteria are not met but a good correlation can still be obtained with hourly or daily intervals, then the measured dataset is scaled up (or down) to long-term using the reference long-term average wind speed and the correlation equation obtained; this method is referred to as the Long-term Adjustment;

- If no correlation can be clearly established between a reference site and the met mast site, the measured data stay unchanged.

4.1.1 Selection of reference dataset

The present section summarises the results of the analysis.

Among the possible set of reference stations, one station was selected and considered suitable for the long-term projection of the data at the met mast. This station is Hopedale (AUT) monitored by Environment Canada (EC). The location of this station is given in the table below.

Table 4-1: Identification of the Long-term Reference

Name	ID	Instruments Height (m)	Latitude	Longitude	Elevation (m)
Hopedale (AUT)	8502400	10.0	N 55° 27' 00.0"	W 60° 13' 00.0"	11.9

4.1.2 Long-term Adjustment

The long-term adjustment consists of:

- Correlating short term data at the met mast with short term data at the reference station;

- Using the obtained linear regression equation, Y = m X + b, where X represents the long-term average wind speed at the reference station and Y is the estimated long-term average at the met mast;

- Applying an adjustment factor (to speed up or scale down) to the met mast short-term data in order to obtain an average wind speed equal to the estimated long-term average at met mast (i.e. Y).

For masts 2602, which displayed 18 months of data recorded, the long-term adjustment method was used for the long-term projection.

The wind speed data of the met mast was correlated to the concurrent wind speed data at the long-term reference station Hopedale (AUT). Good correlation results were obtained with hourly average values (R^2 greater than or equal to 0.70 is good correlation, above 0.85 is excellent). The results of the correlation are given in the following table. Linear regression equations were used to compare the data, where *m* is the slope of the equation, *b* is the intercept, and R^2 is the coefficient of determination.

Table 4-2: Correlations between Reference Station and met mast Wind Speeds

Reference Station	Met Mast	Correlation Period		Hourly Wind Speed Correlations		
		Beginning	End	m	b	R^2
Hopedale (AUT)	**2602**	December 1, 2013	November 30, 2014	1.056	1.4	0.73

The regression equations were then used to estimate the long-term average wind speed at the mast as a function of the long-term wind speed at the reference station. The estimated long-term average at the Hopedale (AUT) is 5.4 m/s. It was estimated by averaging all annual averages over the period 2005 to 2014 (except 2011 having a low recovery rate). The results are presented in the following table.

Table 4-3: Long-term Adjustment factor at the met mast

Met Mast	Wind Speed over Correlation Period (m/s)	Long-term Annual Wind Speed (m/s)	Adjustment Factor (%)
2602	7.2	7.1	-1.4

Finally, the 10-minute measured data recorded at the met mast were scaled by the adjustment factor to reflect the long-term value. In terms of the wind direction data, the one-year dataset for the met mast remained untouched. As a result, the mast has a set of wind speeds and wind directions that are the best estimate of the long-term wind regime.

4.2 Extrapolation to Hub Height

The wind shear exponent, calculated with the measured data, was used to adjust the dataset to hub heights. The results are presented in the following table.

Table 4-4: Estimated Long-term Wind Speed at Hub Heights*

Met Mast	Estimated Long-term Wind Speed at Top Anemometer Height (m/s)	Estimated Long-term Wind Speed at Hub Height (m/s)	
		37 m	40 m
2602	7.1	7.2	7.3

* Estimated using the calculated wind shear

5. Wind Resource Mapping and Projected Energy Production

Met masts provide a local estimate of the wind resource. Met mast locations are chosen based on how representative they are of the project site and in particular for potential wind turbine locations. However, since the number of met masts is usually limited compared to the expected number of wind turbines, it is necessary to build a wind flow map based on these measurements to extend the wind resource assessment to the whole project area.

Wind modeling software, such as MS-Micro and WAsP, are known to produce erroneous wind flows over complex terrain. In this case, Hatch applies a method based on the Ruggedness Index (RIX) to calculate the wind flow for each mast data set while correcting errors on wind speed[4]. All produced wind flows are then merged by a distance-weighting process. When the RIX correction is not applicable, wind flows are calculated with each mast dataset and simply merged together by a distance-weighting process, without a RIX correction.

Once the wind flow map is built, it is possible to optimise the size and layout of the foreseen wind farm for the project, and then to calculate the projected energy production. When necessary, wind turbine hub heights as well as met mast heights are corrected with the estimated displacement height. This is computed to account for the influence of trees on the wind flow (see section 3.2.4). These corrections result in an effective hub height for each wind turbine.

The wind flow and energy production are calculated with specialised software that require, apart from the met masts long-term data, background maps that contain the information on topography, elevation, roughness lengths (related to the land cover) and potential obstacles. This is also used in conjunction with the wind turbine characteristics. Finally, wind farm losses must be estimated in order to complete the energy estimate.

The first part of this section introduces the information and the methodology used to calculate the wind flow.

The next part will present the optimisation process and the results in terms of energy production.

The software used to map the wind resource and to calculate the energy production include:

- WAsP Issue 11.02.0062 from Risø for wind resource mapping;
- Wind Farmer Issue 4.2.20 from Garrad Hassan for layout optimisation and energy production calculations.

5.1 Background Data

5.1.1 Topography and elevation

The topographic and elevation data come from DEM (Digital Elevation Model) files provided by Geobase.

The contour line interval is 5 m within the project area and 20 m outside.

[4] Bowen, A.J. and N.G. Mortensen (2004). WAsP prediction errors due to site orography. Risø-R-995(EN). Risø National Laboratory, Roskilde. 65 pp.

5.1.2 Roughness

The base map for roughness lengths was determined from land cover information included in the NTDB files. This map was then checked and corrected using satellite imagery from Google Earth. Around mast locations and wind turbines, pictures and information noted during site visits were also used to check and modify the land cover information. The spatial resolution considered for the roughness lengths is 30 m.

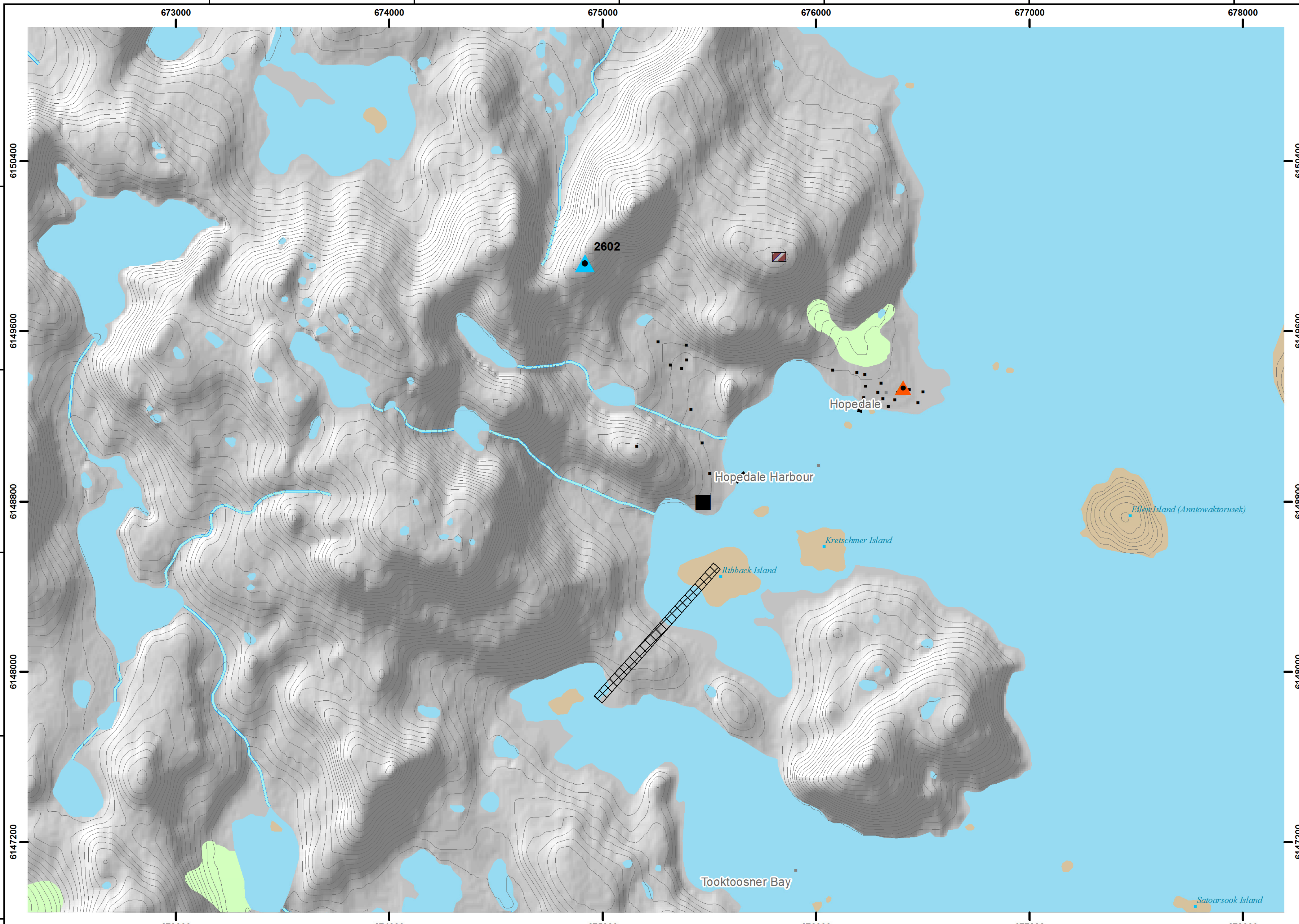
The following table details the roughness lengths used by land cover category.

Table 5-1: Roughness Lengths Categories

Land Cover Type	Roughness Length (m)
Generic vegetation	0.06
Forest	0.5
Water	0
Building	1

5.1.3 Background Map

The background map, showing topography and contour lines is provided on the next page.



Legend

- Met Mast
- EC Hopedale (AUT)
- Diesel generator
- Building
- Contour (5m)
- Wharf
- Watercourse
- Airport area
- Building (other)
- Waterbody
- Island
- Woddlands

N

0 0.25 0.5 1 km

1:20,000

Spatial referencing UTM Zone 20 NAD83.

SOURCE :
Canvec - Natural Resource Canada 1:50 000
Action Canada Conference - Mt.Sophie viewer

NO.	DESCRIPTION	BY	CHK'D	APP'D	DATE

REVISIONS

HATCH

DESIGNED BY SLADJANA PAVLOVIC
DATE: March 10, 2015

DRAWN BY SLADJANA PAVLOVIC
DATE: March 10, 2015

CHECKED BY Patrice Menard
DATE: March 10, 2015

NALCOR

Hopedale - Overview Map

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5.2 Wind Flow Calculation

5.2.1 Terrain Complexity

The wind flow is produced over semi-complex terrain. Wind modeling software, such as MS-Micro (used in Windfarm) and WAsP, are known to produce erroneous wind flows over complex terrain. Depending on the topography, predicted wind speeds can be over or under-estimated at a given location. Errors can reach more than 20% in very complex areas.

In the present case, the complexity of the terrain is considered moderate and its effect on the modelled wind is not considered problematic.

5.2.2 Parameters

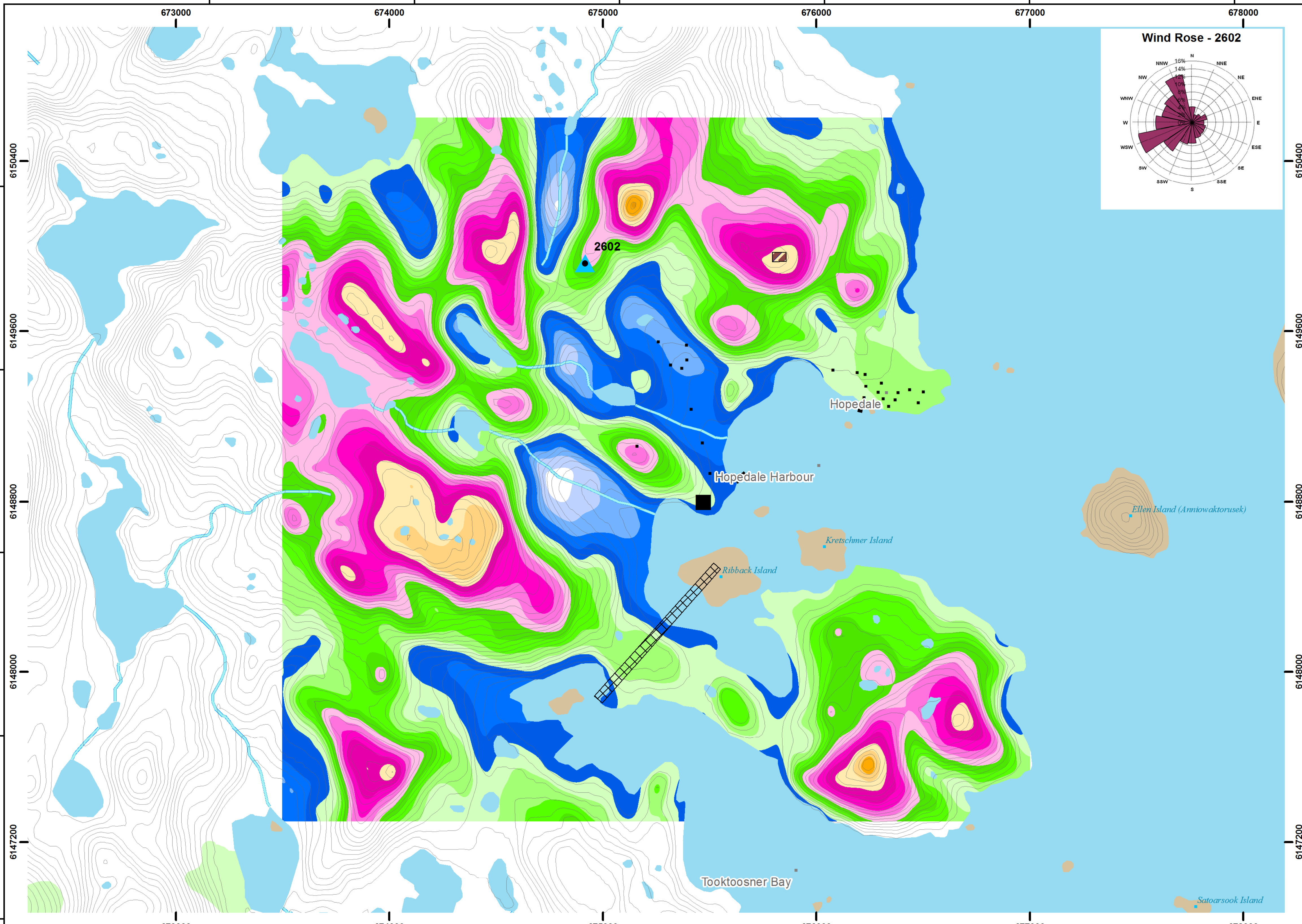
The following parameters were used to calculate the wind flow map.

Table 5-2: Wind Flow Calculation Parameters

Parameter	Value
Wind Resource Grid Spatial Resolution	50 m
Calculation Area	3.5 km by 3.3 km
Reference Mast	2602
Reference Height	Top Anemometer Height
Calculation height	37 m
Vertical Extrapolation Method	Based on measured wind shear
Roughness Change Model	WAsP Standard Model

5.2.3 Results

The wind flow map used for layout optimisation and energy production estimates is presented on the next page.



Legend

- Met Mast
- Diesel generator
- Building
- Contour (5m)
- Wharf
- Watercourse
- Airport area
- Building (other)
- Waterbody
- Island
- Woddlands

WindFlow (37m)
m/s

- < 5
- 5 - 5.25
- 5.25 - 5.5
- 5.5 - 5.75
- 5.75 - 6
- 6- 6.25
- 6.25 - 6.5
- 6.5 - 6.75
- 6.75 - 7
- 7 - 7.25
- 7.25 - 7.5
- 7.5 - 7.75
- 7.75 - 8
- 8 - 8.25
- 8.25 - 8.5
- 8.5 - 8.75
- 8.75 - 9
- 9 - 9.25
- 9.25 - 9.5
- 9.5 <

N

0 0.25 0.5 1 km

1:20,000

Spatial referencing UTM Zone 20 NAD83.

SOURCE :
Canvec - Natural Resource Canada 1:50 000
Action Canada Conference - Mt.Sophie viewer

NO.	DESCRIPTION	BY	CHK'D	APP'D	DATE

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Wind resource map created by Hatch with WAsP v11.02
Height of calculation: 37 m
Spatial resolution of wind resource grid: 50 m
Source file: Hopedale_2602_Grid37m_WF1.grd
Source of data used to create the wind flow:
Topographic data are provided by the Center for Topographic Information (NRCan).
Meteorological data were collected from mast 2602, located 1 km from the center of the map, between 2013/12/01 and 2014/11/30. Data were controlled by Hatch.
Met data were adjusted for long term with reference station EC Hopedale (AUT) (reference period 2005-2014).
It is believed that the present map gives a reliable overall picture of the wind resource.
However, it is advised to confirm any information obtained from this map at any location by on-site measurements.

HATCH

DESIGNED BY SLADJANA PAVLOVIC DATE: March 10, 2015
DRAWN BY SLADJANA PAVLOVIC DATE: March 10, 2015
CHECKED BY Patrice Menard DATE: March 10, 2015

NALCOR

Hopedale - Wind Flow Map 2

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5.3 Forecasting Energy Production

The layout was initially designed in order to maximise energy production. Turbines were spread out inside the project boundaries to minimise wake effects. The preliminary environmental screening and turbine extreme operating conditions also contributed to set the turbine locations.

5.3.1 Preliminary Turbine Selection

A preliminary turbine selection was performed using Windographer software by comparing the performance of different turbines at the location of the met mast, where the dataset was recorded. The main parameters used for the comparison were the capacity factor of the wind turbine for the site specific conditions as well as the turbine purchase cost. Only turbines that meet the following criteria were considered:

- Site's turbine and turbulence class (IEC class II)
- Extreme wind and weather conditions (operation down to -40℃). The minimum 10-minute temperature recording of -33.1℃ during the monitoring campaign confirms the site conditions are within the operating range of the turbine.
- Turbine capacity ranges from 100 kW to 1,000 kW to meet the community load
- Wind turbine's dimensions and weight versus crane capacity and accessibility

Hub heights of about 40 m to 50 m were used for this preliminary analysis.

Standard losses considered include: 12.5% technical losses and 2% wake losses.

The following table provides a summary of the turbine comparison.

Table 5-3: Windographer Results at the Mast Location

Turbine type	Turbine Class	Hub height (m)	Turbine Capacity (kW)	Mean Energy Output (MWh/yr)	Capacity Factor (%)	Turbine purchase cost ($)
Northern Power NPS100 Arctic	IIA	37	100	264	30.2	325,000
Aeronautica AW/Siva29-250	IIA/IIIA	37	250	583	26.6	656,000
Aeronautica AW/Siva47-500	IB/IIA	47	500	1,465	33.5	1,632,000
EWT DW52-250 (EWT250)	IIA	37	250	1,129	51.6	1,980,000
EWT DW52-500 (EWT500)	IIA	37	500	1,741	39.7	1,990,000
EWT DW52-900 (EWT900)	IIA	40	900	2,210	28.0	2,000,000

The capacity factors listed above in table 5-3 are taken from Windographer and may change as a function of the site's optimized layout and should only be used for turbine comparison.

Due the lack of proven experience in remote arctic conditions, the Aeronautica wind turbine models were discarded from the analysis. Northern Power and EWT wind turbines have

been installed and are operating in similar site conditions in Nome, Alaska for EWT or in Kasigluk, Alaska for Northern Power and were thus further compared as part of the analysis.

The average community load at Hopedale during the project lifetime is around 750 kW. The following table shows the results of the WindFarmer optimization models using the required number of turbines to meet that load. The turbines were ranked based on their capacity factor, energy output and simple payback.

Table 5-4: Preliminary Turbine Selection Results

Turbine type	Number of wind turbine required	Total Capacity (kW)	Gross Energy Output (MWh/yr)	Gross Capacity Factor (%)	Total purchase cost (Million $)	Ranking
Northern Power NPS100 Arctic	**8**	**800**	**3,207**	**45.7**	**2.600**	**2**
EWT250	3	750	4,643	70.6	5.940	4
EWT500	2	1000	5,273	60.2	3.980	3
EWT900	**1**	**900**	**3,950**	**50.1**	**2.000**	**1**

* Based on the gross energy output at 30 cents/kWh and the turbine purchase cost only.

Based on information provided by EWT, the 250 kW wind turbine has the same foundation design as the 500 kW and 900 kW machines and nearly the same price ($10,000 difference). Because of the similar turbine costs of the three EWT models, from a financial point of view, the EWT900 becomes the most suitable having the lowest simple payback, and would also benefit from potential lower constructability and BOP cost.

The Northern power NPS100 Arctic can also be considered as potential candidates for the Hopedale project since it is a proven turbine in arctic conditions, and would provide for more redundancy due to number of turbines. The NPS100 has the advantage of being a smaller turbine and would be less difficult from a logistic and crane accessibility stand point.

The NPS100 and EWT900 turbines are two models that meet the wind class of the site and have proven technology for cold and icy environments.

Even though a more detailed turbine selection exercise will be required in later phase of the project, the NPS100 and EWT900 are considered suitable candidate turbines in order to complete the preliminary energy estimates for the potential Hopedale project.

5.3.2 Layout Optimization

The following section shows the WindFarmer modeling results which further refines the energy estimates for the turbines selected at the potential turbine positions and to confirm the capacity factor values. The table below outlines the parameters and constraints assumed to influence optimisation.

Table 5-5: Layout Optimisation Parameters and Constraints

Parameter / Constraint	Value	
Annual Air Density	1.31 $kg.m^{-3}$ at 123 m.a.s.l.	
Turbulence Intensity	13.6% at mast 2602 ***Note****: average value for information, the turbulence intensity is actually entered by wind-speed bins and by direction for energy prediction calculation*	
Exclusion areas	Due to the lack of information in regard to setbacks for wind energy projects in Newfoundland and Labrador, general restriction rules were used: - 500 m from habitations - 100 m from public roads - 50 m from lakes and rivers - 2 km by 1 km buffer zone from the airport track	
WTG Minimum Separation Distance	4 rotor diameters	
WTG Model	EWT900	NPS100 Arctic
WTG Rated Power (kW)	900	100
WTG Rotor Diameter (m)	51.5	20.7
WTG Hub Height (m)	40.0	37.0
WTG Power Curve	See Appendix B	
WTG Thrust Curve	See Appendix B	
Number of WTG's	1	8
Wind Farm Capacity (kW)	900	800
Wake Model	Modified Park Model used for optimisation and Eddy Viscosity Model for final energy calculation as recommended by Garrad Hassan	
Maximum Slope	10 degrees	
Optimization Strategy	Layout designed in order to maximise energy production.	

The project layouts are presented at the end of this section.

The layouts are still considered preliminary. Land restrictions, communication corridors, noise and visual impacts, and other site-specific matters need to be evaluated through a detailed environmental assessment. Available land, road and collection system costs are also issues that will need to be addressed before the site layout can be finalized.

5.3.3 Energy production

Once the optimised layout has been produced, the energy production for each wind turbine is calculated. When necessary, wind turbine hub heights as wells as met mast heights are corrected with the estimated displacement height. This is computed to account for the influence of trees on the wind flow. These corrections result in an effective hub height for each wind turbine.

The calculation was executed with the power curves and thrust curves used for the optimisation and presented in Appendix B. The additional losses are described in the next section.

Note that air density is corrected by the software for each turbine location according to its elevation.

The following table is a summary of the estimated energy production. Detailed energy figures are presented per wind turbine on the next page.

Table 5-6: Wind Farm Energy Production Summary

Item	**Layout 1 - EWT900**	**Layout 2 - NPS100 Arctic**
WTG Rated Power (kW)	900	100
WTG Rotor Diameter (m)	51.5	20.7
WTG Hub Height (m)	40.0	37.0
Number of Wind Turbines	1	8
Wind Farm Capacity (kW)	900	800
Mean Free Wind Speed across Wind Farm (m/s)	9.1	8.3
Average Wake Losses (%)	0.0	2.2
Energy Production Before Additional Losses* (MWh/yr)	3,950	3,207
Capacity Factor Before Additional Losses* (%)	50.1	45.7
Additional Losses (%)	14.0	13.8
Net Energy Production (P50) (MWh/yr)	**3,398**	**2,765**
Net Capacity Factor (%)	**43.1**	**39.4**

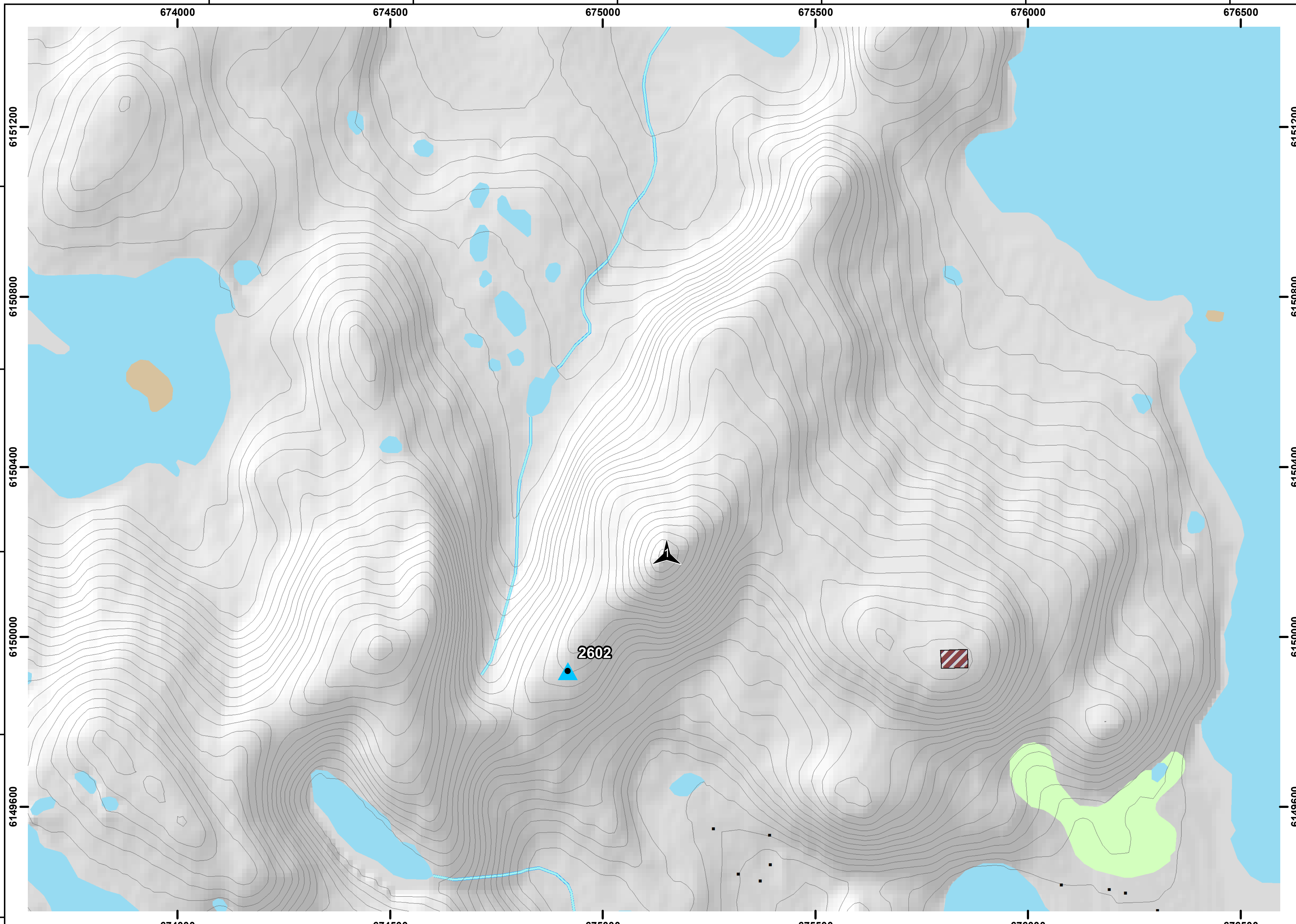
* Includes topographic effect and wake losses

Table 5-7: Forecasted Energy Production at Wind Turbines

Turbine ID	Easting (m)	Northing (m)	Altitude (m)	Mean Free Wind Speed (m/s)	Gross Energy Production* (MWh / Year)	Wake Losses (%)	Gross Energy - Wake* (MWh / Year)	Turbulence Intensity** (%)
Layout 1 - EWT900								
1	675150	6150200	150	9.1	3,950	0.0	3,950	13.4
Layout 2 - NPS100 Arctic								
1	674551	6149815	130	8.1	396	2.1	388	16.7
2	674510	6149911	142	8.3	411	2.5	401	16.4
3	674441	6149998	146	8.3	413	1.3	408	15.6
4	674532	6149996	146	8.4	419	4.4	401	16.9
5	674569	6150082	136	8.3	414	3.2	400	16.1
6	675150	6150200	150	9.1	459	0.7	456	13.5
7	675300	6150503	99	7.8	381	2.8	371	17.1
8	675265	6150587	95	7.9	385	0.8	382	16.3

* Gross energy production includes topographic effect; “Gross energy – Wake” includes topographic effect and wake losses.

** Turbulence Intensity includes ambient turbulence and incident turbulence. The values represent true meteorological turbulence; they should not be compared directly with IEC models and consequently should not be used to establish the wind turbine class.



Legend

- Wind Turbine
- Met Mast
- Building
- Contour (5m)
- Watercourse
- Building (other)
- Waterbody
- Island
- Woddlands

N

0 125 250 500 m

1:10,000

Spatial referencing UTM Zone 20 NAD83.

SOURCE :
Canvec - Natural Resource Canada 1:50 000
Action Canada Conference - Mt.Sophie viewer

NO.	DESCRIPTION	BY	CHK'D	APP'D	DATE

REVISIONS

Turbine model: EWT DW52-900
Number of turbines: 1
Site capacity: 900 KW
Turbine rated power: 900 KW
Hub height: 40 m
File reference: Hopedale_WF2_Lay6.txt

HATCH™

DESIGNED BY DANY AWAD DATE: August 05, 2015	DRAWN BY SLADJANA PAVLOVIC DATE: August 06, 2015
CHECKED BY DANY AWAD DATE: August 06, 2015	

NALCOR

Hopedale - Layout 1

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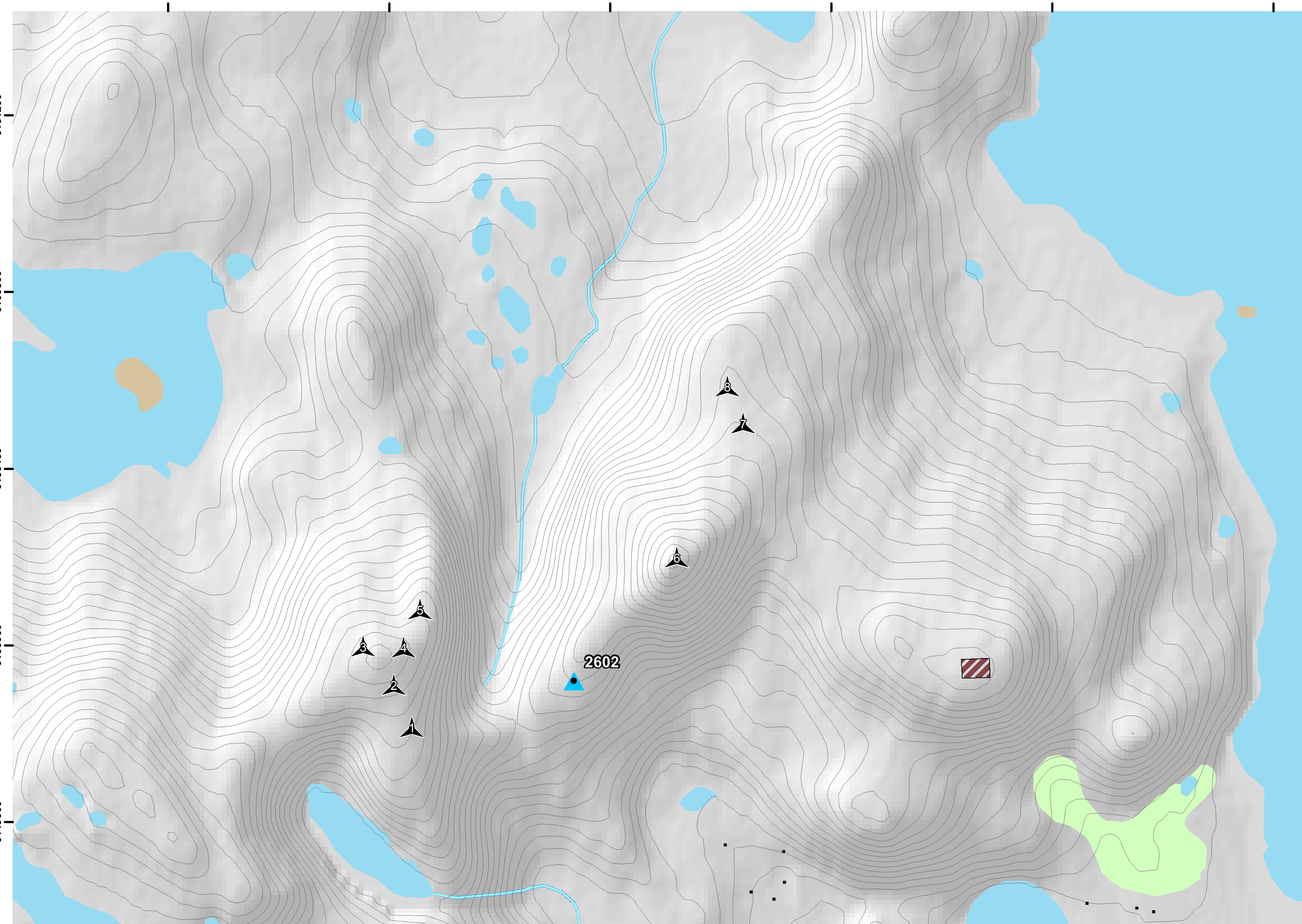
REV. 3



Legend

- Wind Turbine
- Met Mast
- Building
- Contour (5m)
- Watercourse
- Building (other)
- Waterbody
- Island
- Woddlands

N

0 125 250 500 m

1:10,000

Spatial referencing UTM Zone 20 NAD83.

SOURCE :
Canvec - Natural Resource Canada 1:50 000
Action Canada Conference - Mt.Sophie viewer

NO.	DESCRIPTION	BY	CHK'D	APP'D	DATE

REVISIONS

Turbine model: Northern Power 100
Number of turbines: 8
Site capacity: 800 KW
Turbine rated power: 100 KW
Hub height: 37 m
File reference: Hopedale_WF2_Lay7.txt

HATCH

DESIGNED BY DANY AWAD
DATE: August 05, 2015
DRAWN BY SLADJANA PAVLOVIC
DATE: August 06, 2015
CHECKED BY DANY AWAD
DATE: August 06, 2015

NALCOR

Hopedale - Layout 2

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REV. 3

5.3.4 *Losses*

This section provides a description of the estimated losses included in the P50 estimate. These losses include environmental, electrical, availability, turbine performance losses and wake effects. The P50 is defined as the exceedance probability that denotes the level of annual wind-driven electricity generation that is forecasted to be exceeded 50% of the year. Half of the year's output is expected to surpass this level, and the other half is predicted to fall below it. Loss estimates should be reviewed as more detailed information becomes available.

The losses considered are presented in the following table and described hereafter.

Table 5-8: Wind Farm Losses

Loss Category	Loss Type	Losses (%)			
		Layout 1 - EWT900		Layout 2 - NPS100 Arctic	
Environmental	Blade Soiling and Degradation	1.0	**4.5**	1.0	**4.2**
	High Wind Hysteresis	0.2		0.2	
	Icing	3.0		3.0	
	Lightning	0.0		0.0	
	Low Temperature Shutdown	0.4		0.0	
Electrical	Collection Network	1.3	**3.4**	1.3	**2.0**
	Auxiliary power	2.1		0.7	
Availability	Wind Turbine Availability	5.0	**5.8**	6.5	**7.3**
	Collection Network Outage	0.6		0.7	
	Grid Availability	0.2		0.2	
Turbine Performance	Out-of-range Operation	1.0	**1.0**	1.0	**1.0**
Wake effects	Internal Wake Effects	0.0	**0.0**	2.2	**2.2**
	External Wake Effects	0.0		0.0	
	Total*	**14.0**		**15.7**	

* The total is the cumulated effect of the different losses and not their direct summation

Blade soiling and Degradation refers to the reduction of the blade's aerodynamic performance due to dust and/or insects. It also takes into account the future blade degradation attributed to wear of the blade's surface. The Hopedale project is not situated in a particularly dusty environment. This value is consistent with what is generally observed within the industry.

High wind hysteresis losses are caused by the control loop of the turbine around cut-out wind speed. They depend on the wind turbine design.

These estimations are based on the turbines' control loop specifications and high wind hysteresis simulations. Based on the available wind distribution at the mast, the loss induced by the hysteresis loop is 0.2%.

Icing losses happen in different ways: ice accumulation on blades alter their aerodynamic performance, nacelle-mounted instruments affected by ice give inaccurate readings and induce turbine control system errors, asymmetric icing causes mass or aerodynamic imbalance leading to vibrations that may force control systems to shut down the turbine. Icing can have different impact on the production of the turbine and the effect is site-specific. Some areas will be more affected by freezing rain or glaze ice and other regions are more prone to have rime ice or in-cloud icing.

Icing losses are estimated from the detection of icing events during met masts data quality control and translating the icing events into production losses. The level of ice is considered moderate as compared to other northern sites (up to 10% of icing losses).

Values should be taken with caution since no proven methodology is available and because the effect and characteristics of ice are highly site-specific. The uncertainty associated to these aspects is taken into account in the global uncertainty assessment.

Lightning has the potential to damage the turbine control system but also the blade integrity. Modern wind turbines have protection devices that most of the time allow continuous operation even after a lightning strike. There is however, a small chance that lightning will impact turbine operation. The lightning losses were estimated according to Environment Canada maps[5].

Low temperature shutdown losses depend on the local climate, the turbine design and the control algorithm. In cold climates, turbine shutdowns can be driven by low temperature detection, even if the wind is blowing. According to the manufacturers' specifications, the wind turbines with cold weather package have an operation threshold of - 40℃. The loss is estimated based on the long-term temperature data measured at Hopedale Environment Canada station.

Collection network loss is considered at the interconnection point. It takes into account various elements, including the length of the cables connecting the wind turbines to the substation and the losses in the substation itself. Losses depend on the design of these elements.

These losses have been estimated by Hatch according to previous experiences with similar project size and conditions. They should be confirmed when the design of the collection network is finalized.

Auxiliary power losses account for various subsystems of a wind turbine that require electrical power, such as control systems or heaters. All of these losses are not always

[5] http://ec.gc.ca/foudre-lightning/default.asp?lang=En&n=42ADA306-1

accounted for in the power curve. For example, cold packages designed for cold climate wind turbines can require energy even when the turbine is stopped.

Based on Hatch's experience, an estimated value is used to account for the consumption of standard auxiliary systems. Specific losses have been added for the Cold Package system delivered with the wind turbines. They have been estimated by simulation according to the Cold Package specifications of the EWT900 and NPS100 Arctic wind turbines.

Wind turbine availability losses represent the percentage of time over a year that the turbine is unavailable for power production. Losses include regular maintenance time and unexpected turbine shutdowns. A given availability rate is normally guaranteed by utility-scale wind turbine manufacturers such as EWT (95%), but in the case of smaller wind turbines (NPS100), no availability warranty will be offered by the manufacturer.

Based on Hatch's experience on wind farms in similar conditions and technology for isolated sites, Hatch considers the estimate of 6.5% to be adequate for the Project with NPS100 units.

This estimation considers a standard maintenance schedule of 1 day per year per turbine, plus unscheduled repairs and delays due to site accessibility and weather conditions. This is based on information provided by the client that wind turbines will be considered as non-essential grid components and thus deficiencies will be considered as low priority, so that individual units may remain out of service for periods longer than normally considered.

Collection Network Availability: The collection network may be out of service, stopping energy delivery from the turbines to the grid. Collection network outage losses include shutdown time for scheduled maintenance and unexpected outages.

Based on the information provided by the client, the Hopedale based operators will manage the site and are expected to have the skills and manpower required to fix any collection system problem in a timely manner. The presence of a support team onsite has a positive impact on the availability of the collection network.

Grid availability losses depend on the utility distribution system quality and capacity. It represents the percentage of time over a year when the grid is not able to accept the energy produced by the wind turbines.

The value used assumes the wind turbines will be connected to the grid operated by NLH, which is assumed to be well maintained and operated.

Out-of-range Operation losses take into account the aspects usually not covered by the power curve warranty such as turbulence, wind shear and yaw errors. Parameters specific to the Project have been used to perform this loss estimate.

Wake Effect corresponds to the deficit in wind speed downstream of a wind turbine. Several models exist to quantify this effect in terms of induced energy losses. Hatch uses the Eddy Viscosity model which corresponds to a CFD calculation representing the development of the velocity deficit field using a solution of the Navier Stokes equations. Because of higher precision as compared to the Park model and recommendations from WindFarmer, the Eddy Viscosity model is used to assess to the wake of the Project. Wake losses are highly

dependent on the layout, especially regarding the distance between the turbine and the layout's compactness.

One of the input in the wake losses calculation is the thrust curve which is provided by the turbine manufacturer for the Project turbine model under consideration.

No other wind farm currently exist in the vicinity of the project. In addition, no future wind farm that may impact the Project in terms of wake is planned. Thus there are no additional wake losses.

6. Conclusions and Recommendations

6.1 Objectives of Analysis

The purpose of this report is to present a full wind resource assessment for the Hopedale site, including the estimation of the forecasted annual energy production.

6.2 Data Quality and Adjustments

The wind data recovery rates at the monitoring site, for the analysis period, exceed industry standards except for A4, with recovery rates ranging from 85.1% to 98.6% for the primary anemometers and 97.4% for the primary wind vane.

The measured data were adjusted to long-term through correlation with Environment Canada's Hopedale (AUT) station, located 2 km away from the project area. The long-term adjustment method was applied since it was considered to be the best method for producing a representative dataset for the expected life of the project.

6.3 Wind Resource

The annual average wind speed at the met mast is a result of the measurements and the long-term adjustment. These wind speeds are summarised in the table below for top anemometer and hub heights.

Table 6-1: Estimated Long-term Wind Speeds

Mast (Measurement Height)	Estimated Long-term Wind Speed at Measurement Height (m/s)	Estimated Long-term Wind Speed at Hub Height (m/s)	
		37 m	40 m
2602 (35 m)	7.1	7.2	7.3

The long-term dataset at the met mast was used to build the wind flow across the project area.

The complexity of the terrain is considered moderate and its effect on the modelled wind is not considered problematic.

6.4 Forecasted Energy Production

The preliminary turbine selection analysis specified two suitable turbine models: EWT900 and NPS100 Arctic. These models were proven to be best in class for cold and icy environments and suitable for wind-diesel generation in remote community.

The main results of the energy production modeling are summarised in the table below.

Table 6-2: Forecasted Annual Energy Production

Item	Layout 1 - EWT900	Layout 2 - NPS100 Arctic
WTG Rated Power (kW)	900	100
Number of Wind Turbines	1	8
Wind Farm Capacity (kW)	900	800
Annual Net Energy Production (MWh/yr)	**3,398**	**2,765**
Net Capacity Factor (P50) (%)	**43.1**	**39.4**

There remains some uncertainty regarding loss estimates, which should be reassessed as more information becomes available, particularly in relation to warranty contracts and maintenance schedules. Note that the Annual Net Energy Production represents the total forecasted energy production by the wind turbines. The effective energy production used to displace fuel will be a bit lower and vary depending on the chosen layout scenario (type and number of wind turbines), timewise power load and wind resource.

6.5 Recommendation

It should be noted that a number of additional studies and more detailed analysis will be required to refine and validate the turbine selected, the turbine position, the energy and losses.

The integration optimization report will show which turbine model is considered optimal for the Hopedale site based on energy cost, control capabilities and logistics and provide recommendations for further analysis and studies prior to implementation.

References

[1] International Energy Agency Programme, *Recommended practices for wind turbine testing and evaluation – Task 11: Wind Speed Measurement and Use of Cup Anemometer*, 1999

[2] National Renewable Energy Laboratory, *Wind Resource Assessment Handbook*, 1999

[3] International Electrotechnical Commission, *Wind Turbines - Part 1: Design Requirements*, IEC 61400-1, Ed. 3, 2005-08.

[4] International Electrotechnical Commission, *Wind Turbines - Part 12-1: Power performance measurements of electricity producing wind turbines*, IEC 61400-12-1, Ed. 1, 2005.

[5] A Practical Guide to Developing a Wind Project, *Wind Resource Assessment*, 2011

Appendix A

Views at Mast Sites

View Facing North

View Facing East

View Facing South

View Facing West

Figure – A1: Views from Base of Mast 2602

Appendix B

Wind Turbine Data

EWT DW52-900

The power curve and the thrust curve were provided to Hatch by Emergya Wind Technologies.

Table – B1: EWT Wind Turbine Performance Curves

Rotor Diameter: 51.5 m	**Hub Height: 40 m**	**Air Density: 1.225 kg.m^{-3}**	**Turbulence Intensity: N/A**
Wind Speed at Hub Height (m/s)	**Electrical Power (kW)**	**Wind Speed at Hub Height (m/s)**	**Thrust Coefficients**
0	0	0	0.000
1	0	1	0.000
2	0	2	0.000
3	7	3	0.866
4	30	4	0.828
5	69	5	0.776
6	124	6	0.776
7	201	7	0.776
8	308	8	0.753
9	439	9	0.722
10	559	10	0.692
11	698	11	0.613
12	797	12	0.516
13	859	13	0.441
14	900	14	0.368
15	900	15	0.296
16	900	16	0.241
17	900	17	0.199
18	900	18	0.168
19	900	19	0.143
20	900	20	0.124
21	900	21	0.109
22	900	22	0.096
23	900	23	0.085
24	900	24	0.075
25	900	25	0.067

NPS100

The power curve and the thrust curve were provided to Hatch by Northern Power.

Table – B2: NPS100 Wind Turbine Performance Curves*

Rotor Diameter: 20.7 m	**Hub Height: 37 m**	**Air Density: 1.225 kg.m^{-3}**	**Turbulence Intensity: N/A**
Wind Speed at Hub Height (m/s)	**Electrical Power (kW)**	**Wind Speed at Hub Height (m/s)**	**Thrust Coefficients**
0	0	0	0
1	0	1	0
2	0	2	0
3	0	3	0
4	3.7	4	1.072
5	10.5	5	0.963
6	19.0	6	0.866
7	29.4	7	0.820
8	41.0	8	0.754
9	54.3	9	0.687
10	66.8	10	0.616
11	77.7	11	0.548
12	86.4	12	0.491
13	92.8	13	0.436
14	97.3	14	0.391
15	100.0	15	0.347
16	100.8	16	0.316
17	100.6	17	0.286
18	99.8	18	0.261
19	99.4	19	0.239
20	98.6	20	0.222
21	97.8	21	0.206
22	97.3	22	0.194
23	97.3	23	0.184
24	98.0	24	0.175
25	99.7	25	0.167

* Power curve of the Northern Power 100 – standard model

Patrice Ménard
PM:pm

EWT	Emergya Wind Technologies BV
	Engineering

Category:	Specification	Page 1 / 11
Doc code:	S-1000920	

Created by:	JT	Creation Date:	24-07-09
Checked by:	MB	Checked Date:	24-07-09
Approved by:	TY	Approved Date:	05-04-11

Title:

Specification

DIRECTWIND 52/54*900 Technical Specification

Revision	Date	Author	Approved	Description of changes
02	02-03-12	MB	TY	Format, minor text, blades, options
01	28-11-11	LE	TY	Corrections and drawings
-	-	-	-	-
-	-	-	-	-
-	-	-	-	-
-	-	-	-	-

Emergya Wind Technologies BV
Building ‘Le Soleil’ - Computerweg 1 - 3821 AA Amersfoort - The Netherlands
T +31 (0)33 454 0520 - F +31 (0)33 456 3092 - www.ewtinternational.com

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1 Introduction

This document provides a technical overview of the *DIRECTWIND* 52/54*900 Wind Turbine designed for the IEC class II/III application. It is to be read in conjunction with document S-1000921 “Directwind 52/54*900 Electrical Specification”.

2 Technical Description

The *DIRECTWIND* 52/54*900 is a direct-drive, variable speed, pitch regulated, horizontal axis, three-bladed upwind rotor wind turbine.

The gearless direct-driven synchronous generator operates at variable speed. This is made possible by an actively controlled AC-DC-AC IGBT power converter connected to the grid. Benefits of this design are low maintenance, constant power output at wind speed above rated, and relatively low structural loads compared to constant-speed stall-controlled or constant-speed pitch-controlled wind turbines.

The generator is fully integrated into the structural design of the turbine, which allows for a very compact nacelle design. The drive-train makes use of only one main bearing, whereas classic designs have separately supported main shaft, gearbox and generator. All dynamically loaded interfaces from the blades to the foundation are sturdy flange connections with machined surfaces, and high tensile steel pre-stressed bolt connections are used.

2.1 Operation and safety system

The turbine operates automatically under all wind conditions and is controlled by an industrial PLC (Programmable Logic Controller). The cut-in wind speed is approximately 3m/s. When the rotational speed reaches the cut-in threshold, the power converter begins to deliver power to the grid.

The power converter controls the generator power output and is programmed with a power set-point versus rotor speed curve. Below rated wind speed the power output is controlled to optimise rotor speed versus aerodynamic performance (optimum λ-control). Above rated wind speed the power output is kept constant at rated value by PD-controlled active blade pitching.

The dynamic responses of the drive train and power controller are optimised for high yield and negligible electrical power fluctuations. The variable speed rotor acts as a flywheel, absorbing fluctuating aerodynamic power input. The turbine controllers are located in the rotor hub and the tower base (with remote IO in the nacelle) and carry out all control functions and safety condition monitoring. In the case of a fault, or extreme weather conditions, the turbine is stopped by feathering of the blades to vane position (blades swivelled to 90^0 with respect to rotor’s rotational plane). In case of power loss, an independent battery backup system in each blade ensures the blades are feathered.

In the case of less serious faults which have been resolved, or when extreme weather conditions have passed, the turbine restarts automatically to minimise downtime.

2.2 Generator

The multiple-pole, direct-drive generator is directly mounted to the hub. The stator is located in the non-moving outer ring and the wound pole, separately excited rotor rotates on the inner ring.

The generator is designed such that all aerodynamic forces are directly transferred to the nacelle construction without interfering with the generator-induced loads.

2.3 Power Converter

The power converter is an AC-DC-AC IGBT active switching converter. It controls the generator to operate in its optimum range, and maintains power quality to the grid. The inverter can produce unity power factor (cosΦ=1) to the grid under all load conditions. Power factor is also controllable within limits.

2.4 Rotor

The rotor is a three bladed construction, mounted up-wind of the tower. Rotational speed is regulated by active blade adjustment towards vane position. Blade pitch is adjusted using an electric servomotor on each of the blades.

Each blade has a complete, fully independent pitch system that is designed to be fail-safe. This construction negates the need for a mechanical rotor brake. The pitch system is the primary method of controlling the aerodynamic power input to the turbine.

At below rated wind speed the blade pitch setting is constant at optimum aerodynamic efficiency. At above rated wind speed the fast-acting control system keeps the average aerodynamic power at the rated level by keeping the rotor speed close to nominal, even in gusty winds.

The rigid rotor hub is a nodular cast iron structure mounted on the main bearing. Each rotor blade is connected to the hub using a pre-stressed ball bearing. It is sufficiently large to provide a comfortable working environment for two service technicians during maintenance of the pitch system, the three pitch bearings and the blade root from inside the structure.

2.5 Rotor blade set

The rotor blades are made of fibreglass-reinforced epoxy. The aerodynamic design represents state-of-the-art technology and is based on a pitch-regulated concept. No extenders are used and the aerodynamic design is optimal for this rotor diameter.

2.6 Main bearing

The large-diameter main bearing is a specially designed three row cylindrical roller bearing. The inner non-rotating ring is mounted to the generator stator. The outer rotating ring is mounted between the hub and generator rotor. The bearing takes axial and radial loads as well as bending moments. Entrance to the hub is through the inner-bearing ring. The bearing is greased by a fully automatic lubrication system controlled by the turbine PLC.

2.7 Nacelle

The nacelle is a compact welded construction which houses the yaw mechanism, a service hoist and a control cabinet. Both the generator and the tower are flanged to the nacelle. The geometry of the construction assures an ideal transfer of loads to the tower and, with the absence of a shaft and gearbox, results in a simple design ensuring easy personnel access.

2.8 Yaw system

The yaw bearing is an internally geared ring with a pre-stressed four point contact ball bearing. Electric planetary gear motors yaw the nacelle. The yaw brake is passive and is based on the friction of brake pads sitting directly on the bearing ring, keeping the yaw system rigid under most loading conditions.

2.9 Tower

The nacelle assembly is supported on a tubular steel tower, fully protected against corrosion. The tower allows access to the nacelle via a secure hinged access door at its base. The tower is fitted with an internal ladder with safety wire and optional climb assistance, rest platforms and lighting. Standard hub heights are 35, 40, 50 and 75 metres.

2.10 Anchor

The turbine is supported by a concrete foundation. The connection to this foundation is provided by means of a cast-in tube or rod anchor.

2.11 Control System

2.11.1 Bachmann PLC

The M1 controller perfectly combines the openness of a PC-based controller with the reliability of industrial hardware platforms. Designed to withstand the toughest ambient conditions it guarantees error-free use over long periods of time.

A modern system architecture designed for consistent network-capability permits the easy integration of the M1 into the environment of the controller and system peripherals. Real-time ethernet permits the real-time networking of the controllers, and the support of all standard Fieldbus systems permits the connection of standard external components.

2.11.2 DMS

DIRECTWIND Monitoring System – EWT's proprietary HMI featuring local monitoring and control at the turbine, integrated into a remote-access SCADA. DMS offers individual turbine control and total park monitoring and data logging from your Wind Turbine, Wind Park or internet access point.

2.12 Earthing and lightning protection

The complete earthing system of the wind turbine incorporates:

1. Protective earthing:
   A PE connection ensures that all exposed conductive surfaces are at the same electrical potential as the surface of the Earth, to avoid the risk of electrical shock if a person touches a device in which an insulation fault has occurred. It ensures that in the case of an insulation fault (a "short circuit"), a very high current flows, which will trigger an over-current protection device (fuse, circuit breaker) that disconnects the power supply.

2. Functional earthing:
   Earthing system to minimize and/or remove the source of electrical interference that can adversely affect operation of sensitive electrical and control equipment.

   A functional earth connection serves a purpose other than providing protection against electrical shock. In contrast to a protective earth connection, the functional earth connection may carry electric current during the normal operation of the turbine.

3. Lightning protection:
   To provide predictable conductive path for the over-currents in case of a lightning strike and electromagnetic induction caused by lightning strike and to minimize and/or remove dangerous situations for humans and sensitive electrical equipment.

Since the mechanical construction is made of metal (steel), all earthing systems are combined.

2.13 Options

The following options are available:

- Cold climate operation (rated for operation down to -40°C)
- Ice detection and/or prevention system
- Aviation lights
- Shadow flicker prevention
- Low Voltage Ride-through (LVRT)
- Service lift (75m tower only)
- G59 protection relay

3 Technical Data

Where data are separated by "/" this refers to the respective rotor diameter (52 / 54 m).

3.1 Wind and Site Data

Wind class	II / III according to IEC 61400 – 1
Max 50-year extreme	59.5 / 52.5 m/s
Turbulence class	A (I_{15} = 0.16)
Maximum flow inclination (terrain slope)	8°
Max ann. mean wind speed at hub height	8.5 / 7.5 m/s
Nominal air density	1.225 kg/m³

3.2 Operating Temperature

	Standard	Cold Climate
Min ambient operating	-20°C	-40°C
Max ambient operating	+40°C	+40°C

3.3 Cooling

Generator cooling	Air cooled
Converter cooling	Water or air cooled (configuration-dependent)

3.4 Operational Data

Cut in wind speed	3 m/s
Cut out wind speed	25 m/s
Rated wind speed	14 / 13.5 m/s
Rated rotor speed	26 rpm
Rotor speed range	12 to 33 rpm
Power output	900kW
Power factor	1.0 (adjustable 0.95 lagging to 0.95 leading) Measured at LV terminals

3.5 Rotor

Diameter	52 / 54 m
Type	3-Bladed, horizontal axis
Position	Up-wind
Swept area	2,083 / 2,290 m²
Power regulation	Pitch control; Rotor field excitation
Rotor tilt angle	5°

3.6 Blade Set

Type	PMC 24.5 / 25.8
Blade length	24.5 / 25.8 m
Chord at 22.0 m	0.879 m (90% of 24.5m blade radius)
Chord at 23.5 m	0.723 m (90% of 25.8m blade radius)
Chord Max at 5.5 m	2.402 m
Aerodynamic profile	DU 91, DU 98 and NACA 64618
Material	Glass reinforced epoxy
Leading edge protection	PU coating
Surface colour	Light grey RAL 7035
Twist Distribution	11.5^0 from root to 5.5m then decreases linearly to 0.29^0, then non-linearly to 0^0

3.7 Transmission System

Type	Direct drive
Couplings	Flange connections only

3.8 Controller

Type	Bachmann PLC
Remote monitoring	DIRECTWIND Monitoring System, proprietary SCADA

3.9 Pitch Control and Safety System

Type	Independent blade pitch control
Activation	Variable speed DC motor drive
Safety	Redundant electrical backup

3.10 Yaw System

Type	Active
Yaw bearing	4 point ball bearing
Yaw drive	3 x constant speed electric geared motors
Yaw brake	Passive friction brake

3.11 Tower

Type	Tapered tubular steel tower
Hub height options	HH = 35, 40, 50, 75 m
Surface colour	Interior: White RAL 9001, Exterior: Light grey RAL 7035

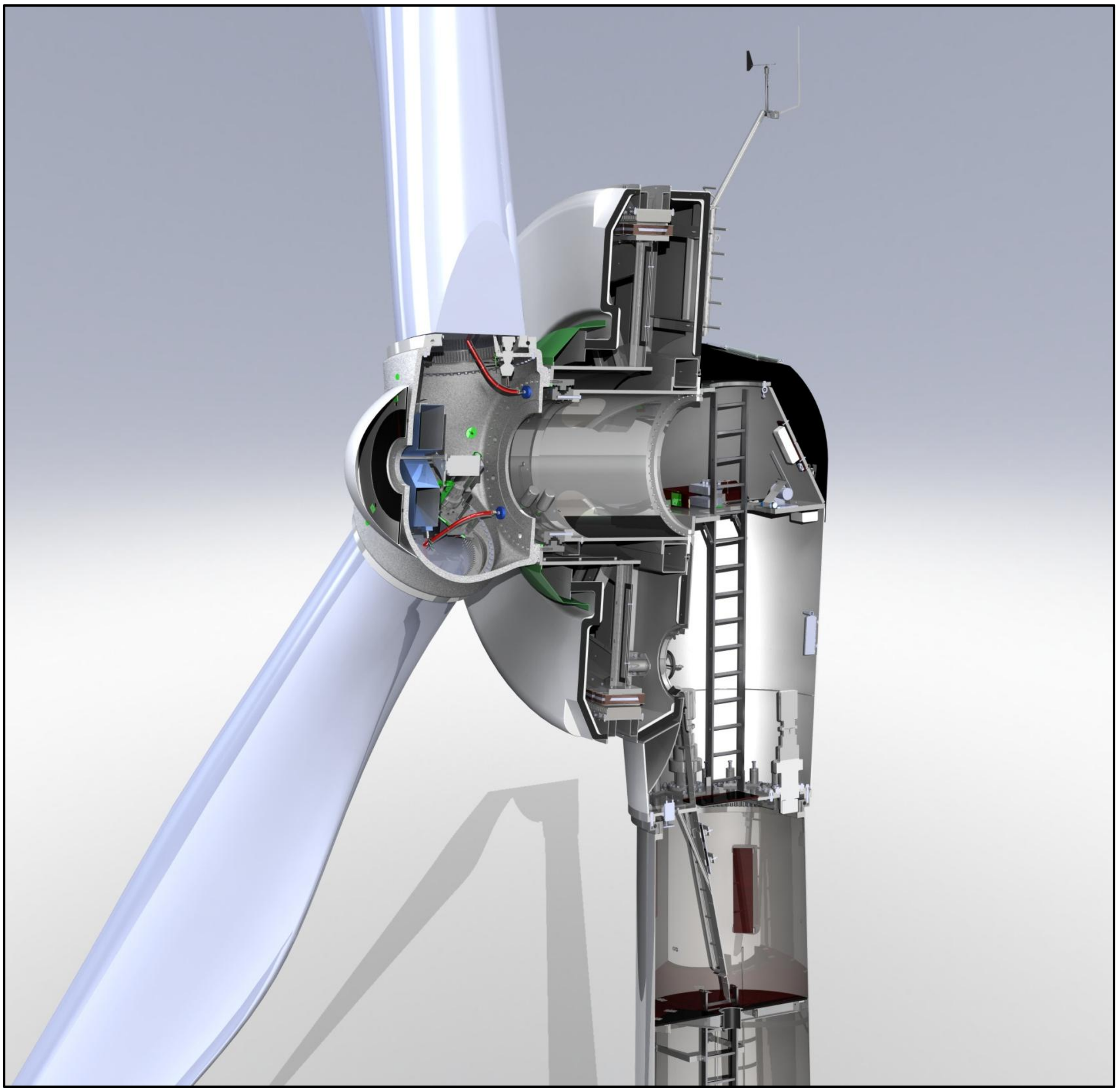
3.12 Mass Data

Hub	9,303 kg
Blade – each	1,919 / 1,931 kg
Rotor assembly	15,060 / 15,096 kg
Generator	30,000 kg
Nacelle assembly	10,000 kg
Tower HH35	28,300 kg
Tower HH40	34,000 kg
Tower HH50	46,000 kg
Tower HH75	86,500 kg

3.13 Service Brake

Type	Maintenance brake
Position	At hub flange
Calipers	Hydraulic 1-piece

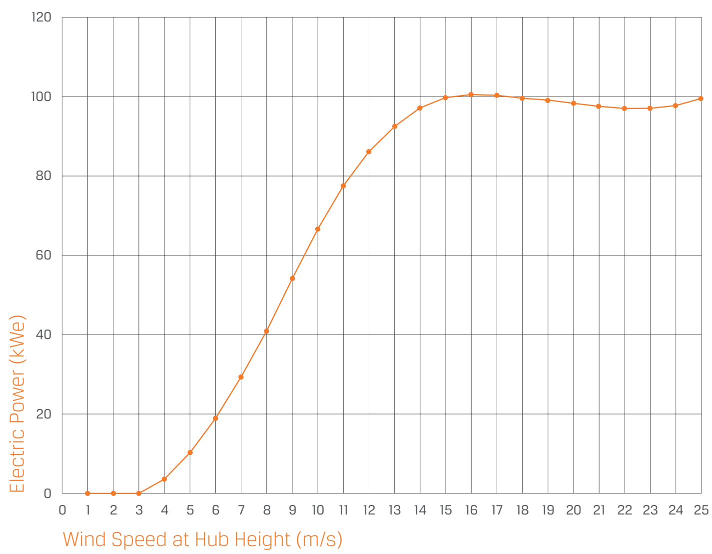
APPENDIX 1: 3D image of main turbine components



Specifications

Northern Power® 100

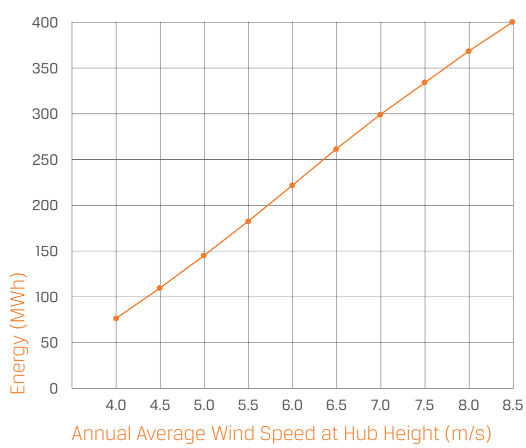
Power Curve: 21-Meter Rotor Standard Air Density (1.225 kg/m³)



Wind Speed (m/s)	Power (kWe)	Wind Speed (m/s)	Power (kWe)
1	0	14	97.3
2	0	15	100.0
3	0	16	100.8
4	3.7	17	100.6
5	10.5	18	99.8
6	19.0	19	99.4
7	29.4	20	98.6
8	41.0	21	97.8
9	54.3	22	97.3
10	66.8	23	97.3
11	77.7	24	98.0
12	86.4	25	99.7
13	92.8		

1 m/s = 2.24 mph

Annual Energy Production*: 21-Meter Rotor Standard Air Density, Rayleigh Wind Speed Distribution



Average Annual Wind Speed (mph)	Average Annual Wind Speed (m/s)	Annual Energy Output (MWh/yr)
8.9	4.0	77
10	4.5	110
11	5.0	145
12	5.5	183
13	6.0	222
15	6.5	260
16	7.0	298
17	7.5	334
18	8.0	368
19	8.5	400

*Annual energy production estimates assume standard conditions, 100% availability and no losses.

Northern
POWER SYSTEMS

Specifications

GENERAL CONFIGURATION	DESCRIPTION
Model	Northern Power® 100
Design Class	IEC IIA (air density 1.225 kg/m^3, average annual wind below 8.5 m/s, 50-yr peak gust below 59.5 m/s)
Design Life	20 years
Hub Height	37 m (121 ft) / 30 m (98 ft)
Tower Type	Tubular steel monopole
Orientation	Upwind
Rotor Diameter	21 m (69 ft)
Power Regulation	Variable speed, stall control
Certifications	UL1741, UL1004-4, CSA C22.2 No.107.1-01, CSA C22.2 No. 100.04, and CE compliant

PERFORMANCE	DESCRIPTION (standard conditions: air density of 1.225 kg/m^3, equivalent to 15°C (59°F) at sea level)
Rated Electrical Power	100 kW, 3 Phase, 480 VAC, 60/50 Hz
Rated Wind Speed	14.5 m/s (32.4 mph)
Maximum Rotation Speed	59 rpm
Cut-In Wind Speed	3.5 m/s (7.8 mph)
Cut-Out Wind Speed	25 m/s (56 mph)
Extreme Wind Speed	59.5 m/s (133 mph)

WEIGHT	DESCRIPTION
Rotor (21-meter) & Nacelle (standard)	7,200 kg (16,100 lbs)
Tower (37-meter)	13,800 kg (30,000 lbs)

DRIVE TRAIN	DESCRIPTION
Gearbox Type	No gearbox (direct drive)
Generator Type	Permanent magnet, passively cooled

BRAKING SYSTEM	DESCRIPTION
Service Brake Type	Two motor-controlled calipers
Normal Shutdown Brake	Generator dynamic brake and two motor-controlled calipers
Emergency Shutdown Brake	Generator dynamic brake and two spring-applied calipers

YAW SYSTEM	DESCRIPTION
Controls	Active, electromechanically driven with wind direction/speed sensors and automatic cable unwind

CONTROL/ELECTRICAL SYSTEM	DESCRIPTION
Controller Type	DSP-based multiprocessor embedded platform
Converter Type	Pulse-width modulated IGBT frequency converter
Monitoring System	SmartView remote monitoring system, ModBus TCP over ethernet
Power Factor	Set point adjustable between 0.9 lagging and 0.9 leading
Reactive Power	+/- 45 kVAR

NOISE	DESCRIPTION
Apparent Noise Level	55 dBA at 30 meters (98 ft)

ENVIRONMENTAL SPECIFICATIONS	DESCRIPTION
Temperature Range: Operational	-20°C to 50°C (-4°F to 122°F)
Temperature Range: Storage	-40°C to 55°C (-40°F to 131°F)
Lightning Protection	Receptors in blades, nacelle lightning rod and electrical surge protection
Icing Protection	Turbine designed in accordance with Germanischer Lloyd Wind Guidelines Edition 2003

All Specifications subject to change without notice.

NPS100SS-2222011-US

Appendix C:
Wind Resource Assessment Report – Makkovik

Project Report

November 15, 2015

Newfoundland and Labrador Hydro
Makkovik Wind Project

Distribution

Trevor Andrew – NLH
Asim Haldar – NLH
Bob Moulton – NLH
Timothy Manning – NLH
Terry Gardiner – NLH
Louis Auger – Hatch
Dany Awad – Hatch
Ève-Line Brouillard – Hatch

Final Wind Resource Assessment Report

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DOCUMENT HISTORY

Revision	Date	Description
1	September 3, 2015	Final Version
2	November 15, 2015	Few edits based on comments from NLH on October 30, 2015 – Final Version

EXECUTIVE SUMMARY

In order to assess the potential of Makkovik site for wind power development, a wind resource assessment (WRA) was completed. The site is located near the community of Makkovik, Newfoundland and Labrador, Canada. The site was equipped with one met mast that is described in the table below.

Met Mast	Installation Date	Top Anemometer Height (m)	Elevation (m)	Data Collection* Starts…	Data Collection* Ends…
2603	October 25, 2013	35.0	81	October 25, 2013	April 30, 2015

* A 12 month period is selected to estimate the annual energy production

In the analysis, the quality control process demonstrated that the data recovery rates exceeded 93.5 % on all instruments which meets industry standards for wind measurement campaign. Erroneous or unreliable data were replaced with available redundant data from instruments on the same met mast since these are considered to be equivalent wind measurements.

The **wind speed** measured at the mast is **7.7 m/s** on average. The **winds are dominant from southwest and west-southwest** across the site.

The wind **turbulence intensity** observed at the site is generally **moderate**.

Given the land cover and topography at the mast, the **wind shear exponent**, equal to **0.12** is consistent with the expected value.

Met Mast	Period	Annual Average of Measured Wind Speed* (m/s)	Annual Average of Measured Turbulence Intensity* (%)	Annual Wind Shear
2603	November 1, 2013 to October 31, 2014	7.7	12.0	0.12

** at Top Anemometer Height*

During the data quality control process, icing events were detected on anemometers and wind vanes. **Icing** occurred **1.7% of the time** at the site. Given the site elevation and the temperatures associated with these events, it is likely that about 77% of these events were caused by freezing rain and about 23% were caused by rime ice. Icing events mainly occurred during the months of April and November.

Temperature data were collected at the mast. The monthly averages range from **-16.8°C** in February and December to **14.1°C** in August, with an **annual average** of **-1.8°C** for the analysis period. The coldest 10-minute temperature recording during the data collection period was -32.4°C.

The **air density** was calculated at the mast according to the elevation and the local temperature. The annual value is **1.31 kg/m^3**.

The annual average power density is **637 W/m²**. The most powerful winds come from west-southwest to northwest across the site.

In order to estimate the **long-term wind regime** at the site, several potential **reference stations** with historical data were selected.

The **Hopedale (AUT) station** monitored by Environment Canada, located 77 km away from the potential wind farm site, was selected as the reference station for the long-term extrapolation of the data. The reference station data were then correlated to met mast 2603 and used to translate the short-term data into long-term estimates.

The long-term estimates were then extrapolated from measurement height to hub heights.

Met Mast	Period	Estimated Long-term Wind Speed at Top Anemometer Height (m/s)	Estimated Long-term Wind Speed at Hub Height (m/s) at 37 m / 40 m
2603	November 1, 2013 to October 31, 2014	7.6	7.6 / 7.7

The wind resource estimated at the mast was used to compute the wind flow across the project area. The wind flow was calculated with WAsP 11.01.0016 software, which is an appropriate model for the Makkovik project area which exhibits a moderate terrain complexity.

This wind flow was used to optimise the layout of the potential wind farm and to estimate the energy production with WindFarmer software.

A preliminary turbine selection analysis was completed and two turbine models were selected: Emergya Wind Technologies 900 kW (EWT900) and Northern power 100 (NPS100 Arctic). These models have proven technology in cold and icy environments and are suitable for wind-diesel generation in remote community.

A wind farm layout optimisation was completed taking in consideration energy production, information from the preliminary environmental screening and turbine extreme operating condition.

The main results of the energy production modeling are presented below. Additional losses include blade soiling, icing, collection network losses, auxiliary power consumption, wind turbines availability, high wind hysteresis, low temperature shutdown, collection network outage and grid availability.

Layout	Wind Farm Capacity (kW)	Net Energy Production (MWh/year)	Net Capacity Factor (%)	Wake Losses (%)	Additional Losses (%)
Layout 1 - EWT900	900	3,102	39.3	0.0	14.1
Layout 2 - NPS100 Arctic	500	1,728	39.4	1.1	13.6

Other energy production scenarios will be covered under separate portion of the wind penetration report.

1. Introduction

Hatch has been mandated by Newfoundland and Labrador Hydro (NLH) to carry out a wind resource assessment (WRA) for a potential wind project , located near the community of Makkovik, Newfoundland and Labrador, Canada.

The site was instrumented with one meteorological (“met”) mast. The installation was completed on October 25, 2013. The mast was equipped with sensors at several heights to measure wind speed, wind direction and temperature. The analysed data cover a total measurement period of one year.

The second section of this report presents an overview of the site and the measurement campaign.

The third section presents the main characteristics of the wind climate.

The fourth section details the process used to translate the measured short-term data into long-term data.

The fifth section presents the methodology used to obtain the wind flow map over the project area. The wind flow map optimises the wind farm layout and helps determine monthly and annual energy production estimates. The key resulting values of these estimations are provided, including a description of the losses considered in the net energy calculation.

2. General Information

This section summarises general information about the site, the meteorological (met) mast installed and the measurement campaign.

2.1 Site Description

2.1.1 Site Overview

The community of Makkovik is located in an inlet on the Labrador east coast, approximately 200 km Northeast of Goose Bay. The surroundings of the community consists mainly of bare rock hills with an average elevation of 100 m above sea level.

Figure 2-1: Typical Landscape at the Makkovik Area

2.1.2 Mast Location

The location of met mast 2603 was chosen with agreement between Hatch and NLH. Hatch proceeded with the installation of the mast and followed industry standards [1].

Table 2-1 provides a description of the mast, including the exact coordinates and the elevation.

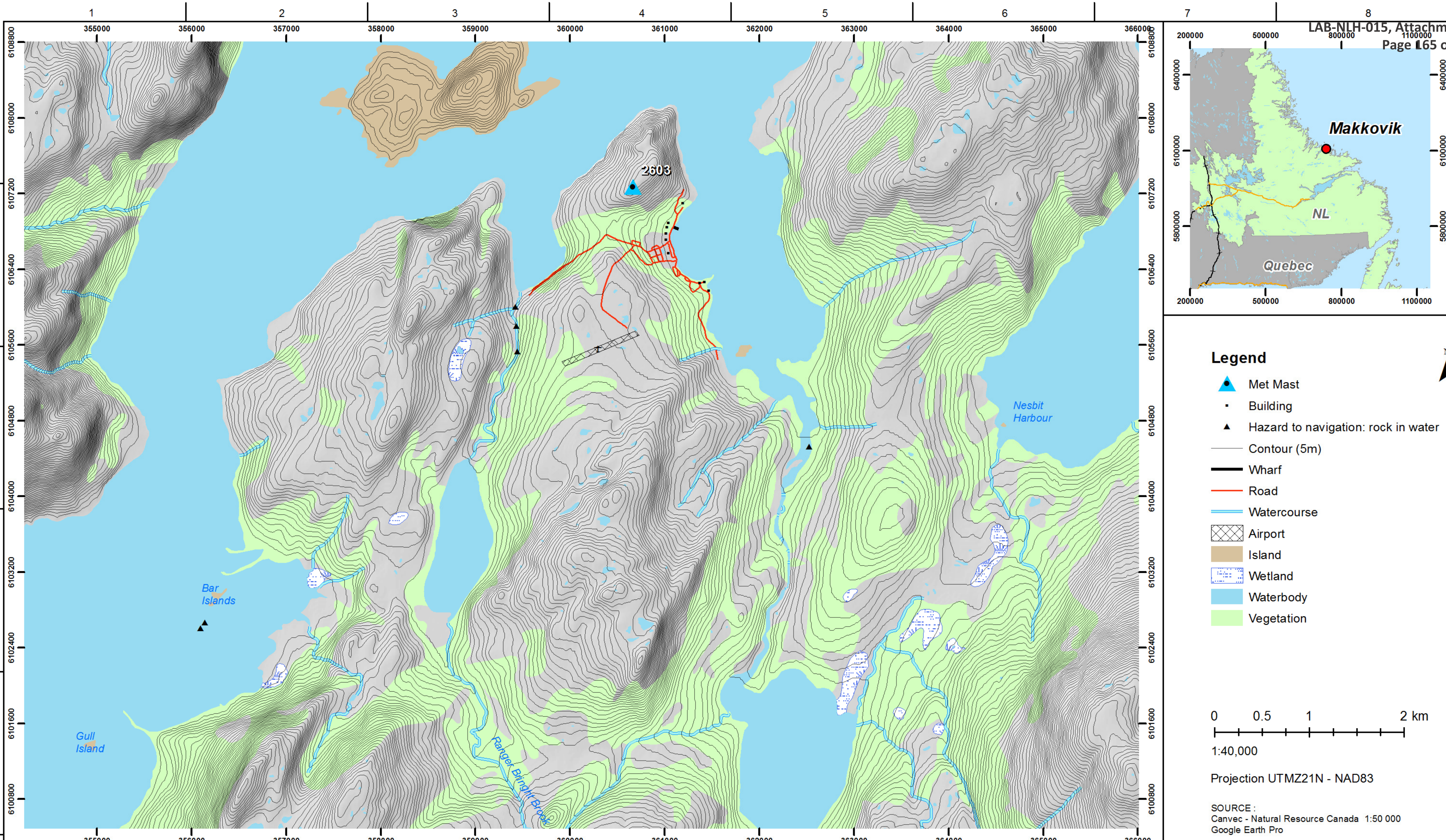
The location of the mast is shown on the map provided on next page.

Table 2-1: Met Mast Characteristics (Coordinate System: NAD83)

ID	Type	Side Length (m)	Height (m)	Latitude	Longitude	Elevation (m)
2603	Square Lattice	0.404	36	N 55° 05' 33.3"	W 59° 11' 00.1"	81

The Makkovik met mast (#2603) is located north of the community on a rocky hill of approximately 100 m elevation. The site consists in smooth bed rock covered in moss.

Pictures have been provided in Appendix A with views in the four main geographical directions at the met mast.



NO.	DESCRIPTION	BY	CHK'D	APP'D	DATE

REVISIONS

HATCH

DESIGNED BY DANY AWAD DATE: July06, 2015

DRAWN BY SLADJANA PAVLOVIC DATE: July06, 2015

CHECKED BY DANY AWAD DATE: July06, 2015

NALCOR

Makkovik - Overview Map

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2.2 Measurement Campaigns

The mast characteristics, instrumentation, installation dates and periods of data collection are provided in this section.

2.2.1 Installation and Collection Dates

The following table provides the date of mast installation and the period of data collection used in the analysis.

Table 2-2: Installation Date and Period of Relevant Data Collection

ID	Installation date	Date and time of first data used	Date and time of last data used
2603	October 25, 2013	November 1, 2013, 00:00 AM	October 31, 2014, 11:50 PM

2.2.2 Instrumentation

2.2.2.1 Sensors Mounting

The met mast was equipped with anemometers and wind vanes mounted on booms at several heights. The dimensions of the booms, their heights and orientations on the mast, were designed to comply with the best practices in wind resource assessment as specified in [1] and [2].

For the met mast, the instrument and installation parameters are provided in the table below. All instruments and met mast underwent regular maintenance checks.

Heated anemometers and wind vanes were installed to increase the data recovery rate during icing periods. An Autonomous Power System (A.P.S.) developed by Hatch was installed to power supply the heating instruments. The A.P.S. consists of a set of batteries charged by a small wind turbine through a controller.

Table 2-3: Installation Parameters of Instruments at the met Mast

Channel	ID	Height (m)	Type	Date Installed	Date Uninstalled	Calibrated / Heated	Primary / Redundant
Mast 2603							
Data Acquisition System							
N/A	N/A	N/A	NRG Symphonie PLUS3	Oct 25, 2013	July 24, 2015	N/A	N/A
Anemometers							
#1	**A1**	**35.0**	**NRG #40C**	**Oct 25, 2013**	**July 24, 2015**	**Yes / No**	**P**
#2	A2	35.0	NRG Icefree III	Oct 25, 2013	July 24, 2015	Yes / Yes	R
#3	A3	26.0	NRG #40C	Oct 25, 2013	July 24, 2015	Yes / No	P

Channel	ID	Height (m)	Type	Date Installed	Date Uninstalled	Calibrated / Heated	Primary / Redundant
#4	A5	26.0	RMYoung 5103-AP	Oct 25, 2013	July 24, 2015	Yes / No	R
#13	A4	17.0	NRG #40C	Oct 25, 2013	July 24, 2015	Yes / No	P
Wind Vanes							
#7	**V1**	**33.0**	**NRG Icefree III**	**Oct 25, 2013**	**July 24, 2015**	**No / Yes**	**P**
#8	V2	26.0	RMYoung 5103-AP	Oct 25, 2013	July 24, 2015	No / No	R
#9	V3	15.0	NRG #200P	Oct 25, 2013	July 24, 2015	No / No	R
Temperature Sensor							
#10	T	34.0	NRG #110S	Oct 25, 2013	July 24, 2015	No / No	P

Note: Lines in bold font correspond to the anemometer and wind vane considered as the principal instruments for wind characterisation at the mast location.

2.2.2.2 Data Acquisition System

For met mast 2603, the instruments were connected to a data acquisition system which stored the data on a memory card. The data were then sent to Hatch computer network by a satellite communication system every 3 days.

3. Meteorological Data Analysis

This section presents a comprehensive analysis of the data collected. In the first section, the quality of the data is reviewed. The characteristics of the wind measured at the mast are then presented in Section 3.2 through a number of relevant parameters:

- monthly and annual average wind speeds;
- wind speed distribution;
- wind direction distribution;
- wind shear;
- turbulence intensity;
- 50-year recurrence wind speed.

In the final section, other climatic information such as measured temperature, calculated air density, wind power density and icing events is presented and discussed.

3.1 Quality Control

The quality and completeness of the data are key factors that determine the reliability of the wind resource assessment.

Data are collected periodically from the met masts and the quality of the data is analysed. This is done by applying a variety of logical and statistical tests, observing the concurrent readings from different instruments and relating these observations to the physical conditions at the site (e.g. wind shading, freezing potential, etc.). The process is semi-automated: the tests are implemented in a computer program developed by Hatch, but the expertise of quality analysts are required to accept, reject or replace data. There are many possible causes of erroneous data: faulty or damaged sensors, loose wire connections, broken wires, data logger malfunction, damaged mounting hardware, sensor calibration drift, icing events and different causes of shading (e.g. shading from the mast or from any obstacles at the site). A list of the possible error categories used during quality control is presented in Table 3-1. Data points that are deemed erroneous or unreliable are replaced by redundant data when available, or removed from the dataset.

The data recovery rate for the analysis period is then calculated for each of the instruments using the following equation:

$$\text{Data recovery rate (\%)} = \frac{\text{Number of valid observations}}{\text{Number of potential observations}} * 100$$

The "Number of valid observations" is evaluated once erroneous or unreliable data are replaced with available redundant data. The "Number of potential observations" is the theoretical maximum number of measurements that could be recorded during the analysis period. A high data recovery rate ensures that the set of data available is representative of the wind resource over the measurement period.

Table 3-1: Quality Control Table

Error Categories
Unknown event
Icing or wet snow event
Static voltage discharge
Wind shading from tower
Wind shading from building
Wind vane deadband
Operator error
Equipment malfunction
Equipment service
Missing data (no value possible)

3.1.1 *Data Replacement Policy*

Erroneous or unreliable data were replaced with available redundant data from instruments on the same met mast since these are considered to be equivalent wind measurements. Replacements were done directly or by using a linear regression equation. Direct replacement is applied to anemometers when the replaced and replacing instruments are of the same model, calibrated, at the same height, and well correlated. Direct replacement is also applied to wind vanes as long as they are well correlated.

A relatively small percentage of the dataset (3%) is replaced by equivalent instruments and it is considered to have a negligible impact on the uncertainty of the measurements.

3.1.2 *Recovery Rates*

The following table presents the recovery rates calculated for each instrument after quality control and after replacements have been completed according to the replacement policy.

Table 3-2: Instruments Data Recovery Rates

Mast ID	A1	A3	A4	V1	T
2603	93.8%	99.3%	93.5%	98.0%	100.0%

Note that the recovery rates for the following instruments are identical, given the replacement policy:

- A1 and A2; A3 and A5
- V1, V2 and V3

3.1.3 *Data History*

The data recovery rates exceed industry standards [5]. A number of data were affected for short periods of time by usual effects, such as shading effect and short period of icing events, and were removed. Other events resulted in data removal; these included the following:

- A2 became out of order as of January 2014;
- The temperature sensor was damaged after a high wind event on November 08, 2014, resulting in a data loss.

3.2 Wind Characteristics

3.2.1 Annual and Monthly Wind Speed

The monthly wind speeds measured at each anemometer are shown in the following figures for mast 2603. The data are presented in two formats (see Figure 3-1 and Figure 3-2):

a) for all instruments, the averaged monthly wind speed measured;
b) for A1, all monthly wind speeds also reported.

Although the results for anemometers A2 and A5 are presented, they will not be considered in further calculations as these sensors were used primarily for quality control and replacement purposes.

As expected, the data confirm that wind speeds increase with height above ground level (see section 3.2.4 for a description of wind shear). Furthermore, the graphs show the seasonal pattern of wind, which decreases towards summer months and increases towards winter months.

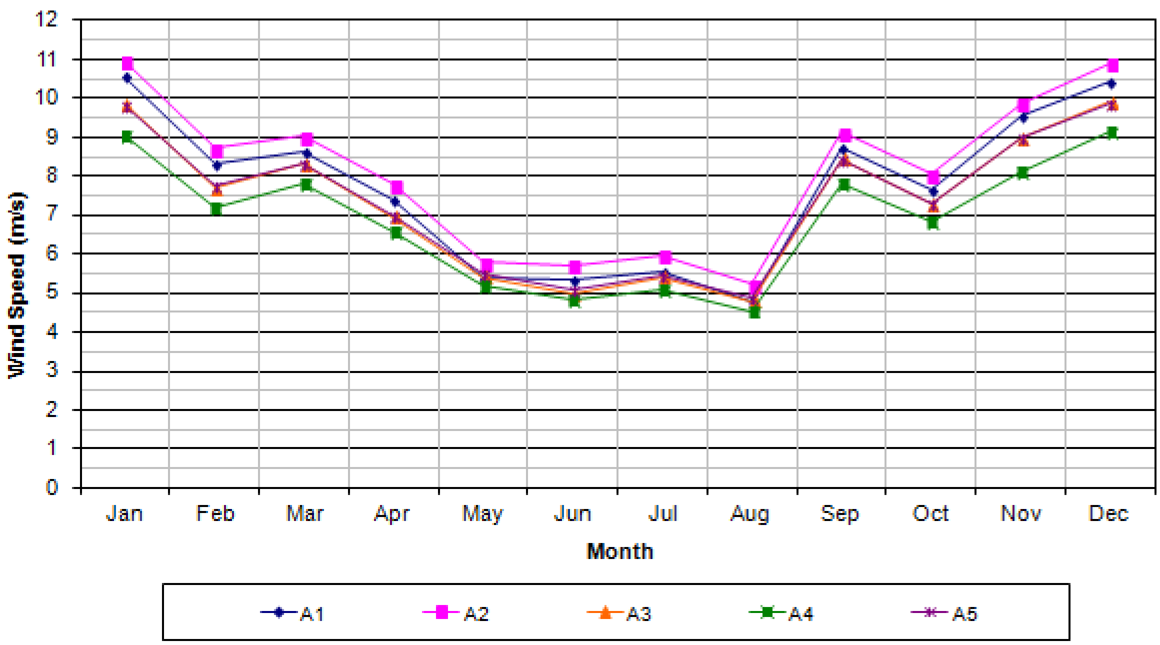


Figure 3-1: Averaged Monthly Wind Speeds for Each Anemometer at Mast 2603, November 1, 2013 to October 31, 2014

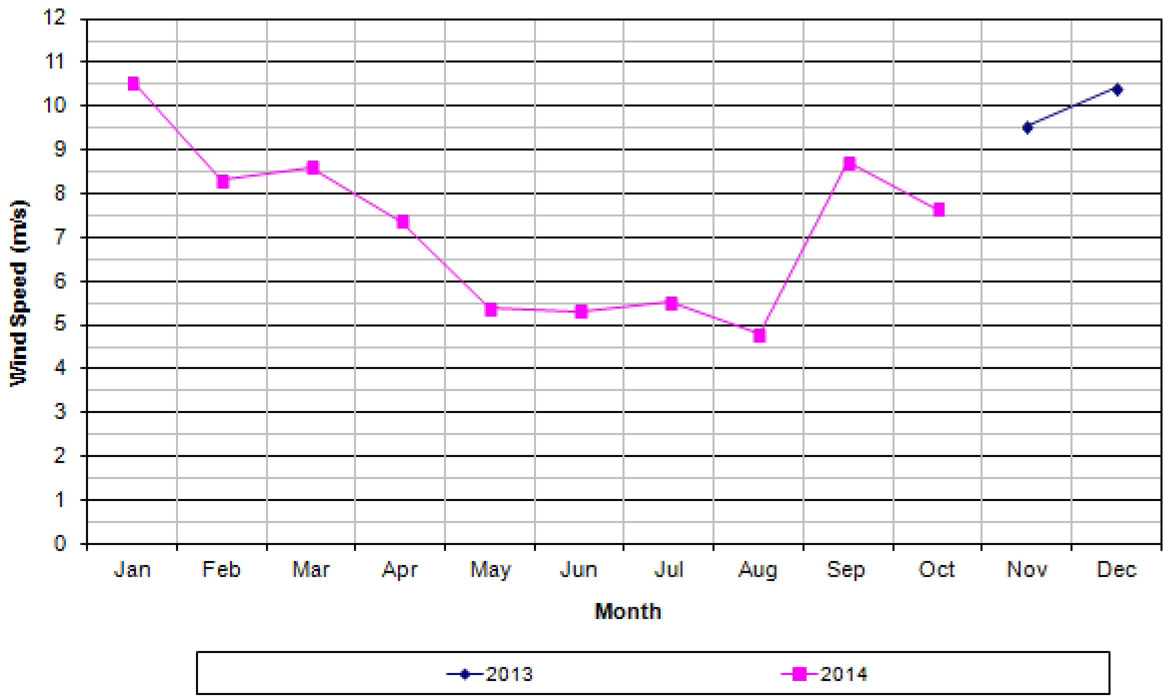


Figure 3-2: Monthly Wind Speeds Measured at the Top Anemometer at Mast 2603, November 1, 2013 to October 31, 2014

The following table provides, the average wind speed and the maximum 1-second gust observed, and specifies the averaging method used and the period of data considered. The averaging method varies as it depends upon the available dataset:

- Annual: average of the wind speed recorded over one or more full years.
- Annualised: the annualised wind speed is a weighted wind speed that is calculated from all available monthly average wind speeds–e.g. if 2 values are available for January and only one is available for February, the February value will have twice the weight of each January value in the final average.
- Average: due to insufficient data collection, the annual average wind speed was not calculated. The value given is the average of all available data.

Table 3-3: Wind Speed Characteristics at the Mast

Mast	Top Anemometer Height (m)	Period	Average Wind Speed (m/s)	Maximum 1-second gust (m/s)	Method
2603	35.0	November 1, 2013 to October 31, 2014	7.7	42.0	Annual

3.2.2 *Wind Speed Frequency Distribution*

The frequency distribution of wind speeds helps to evaluate how much power is contained in the wind (power is proportional to the cube of the wind speed). Wind turbines will produce more power as the wind speed increases (until reaching the "rated" value). Thus, as the frequency of higher wind speeds increases, more power can be produced.

Annual frequency distributions generally exhibit a Weibull shape that is controlled by its "scale factor" (closely linked to the average wind speed) and its shape factor.

The wind speed frequency distribution graph is presented below for the mast[1].

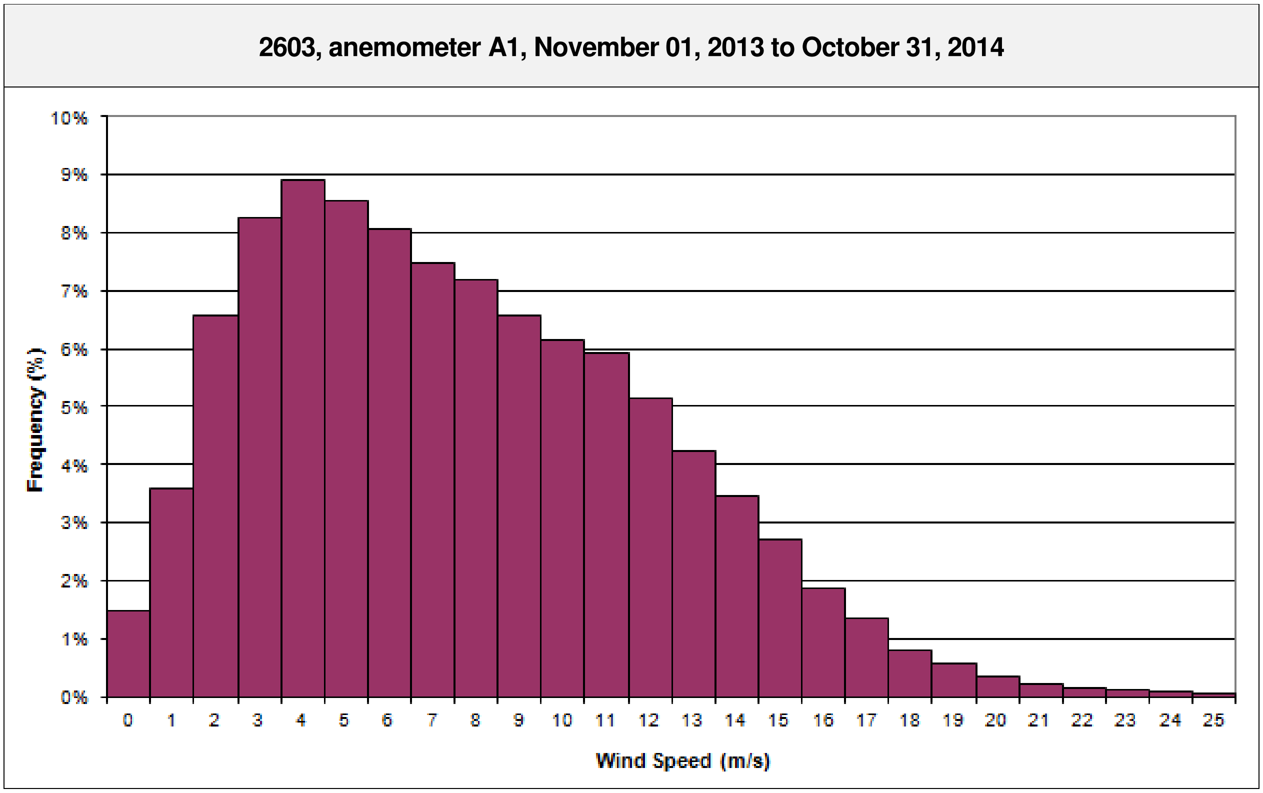


Figure 3-3: Wind Speed Frequency Distribution Graph

3.2.3 *Wind Rose*

The wind rose graph is presented below. The wind rose is divided into the conventional 16 compass sectors (22.5º wide sectors). Note that all compass orientations referenced in this report are based on the true geographic north, rather than the magnetic north.

[1] The 0 m/s wind speed bin indicates the fraction of the total number of measurements with a wind speed between 0 to 0.5 m/s. The other bins are 1 m/s wide and centered on the integer value (e.g.: the 1 m/s wind speed bin indicates the fraction with a wind speed between 0.5 to 1.5 m/s).

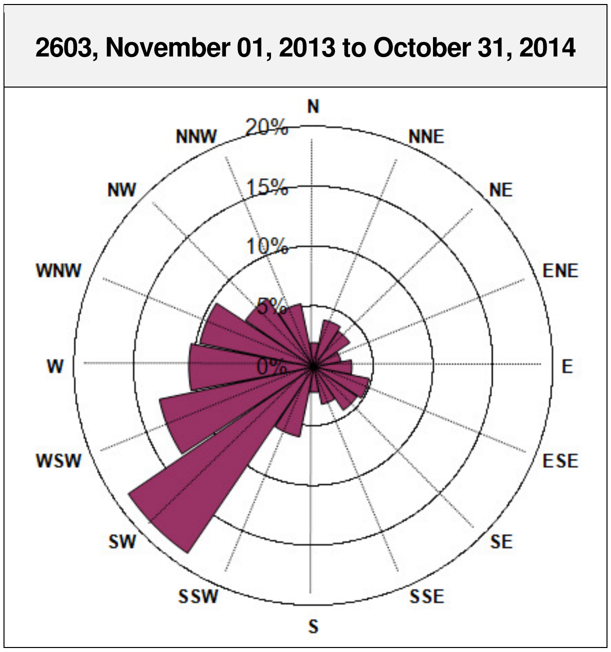


Figure 3-4: Wind Rose Graph

The wind rose indicates that a significant proportion of the wind blows from southwest and west-southwest, across the project area.

Note that wind roses are not adjusted to the long-term. Moreover, differences in wind directions between the levels of measurement are small enough to be neglected. As a consequence, the present wind rose will be considered as representative of the long-term wind rose at hub height.

3.2.4 *Wind Shear*

Wind speeds typically increase with height above the ground, because the frictional drag decreases with altitude. The increase in wind speed with height is referred to as wind shear and is commonly modeled either by a logarithmic law or by a power law.

When the power law is used, the wind shear can be quantified by a wind shear exponent. “Rough” surfaces, such as forested lands and urban areas, have a more pronounced frictional drag than “smooth” surfaces, such as a snow covered field or grasslands–the former will be associated with higher wind shear exponents. Over a smooth, level, grass-covered terrain, the wind shear exponent is typically around 0.14; over snow or calm sea it may be as low as 0.10; and over urban areas or tall buildings it may be as high as 0.40.

The roughness is not the only surface property that has a direct effect on the wind shear. When there is dense vegetation, the vertical wind speed profile is displaced vertically above the canopy, thereby displacing the level of zero wind speed to a certain fraction of the vegetation height above the ground. The “displacement height” is defined as the height at which the zero wind speed level is displaced above the ground. The displacement height is taken into account in all wind shear estimations.

Finally, large topographic variations over short distances may also impact the wind vertical profile and thus affect the wind shear.

Hatch recommends using the log law to estimate the wind shear at mast locations. Internal studies have shown that the accuracy of the wind shear estimate is slightly improved with the log law when compared to the power law. When available, three wind speed measurements, each at a different height, are used and a log law curve is fitted through the average wind speeds at these heights. With the log law, the parameter that reflects roughness is called the roughness length, instead of the wind shear exponent. However, an equivalent wind shear exponent is calculated between the top anemometer height on a mast and the hub height for easier interpretation.

The equivalent wind shear exponent presented in this report was calculated between the top anemometer height of the mast and hub heights of 37.0 m and 40.0m. The calculation was based on the measured wind speed at the anemometer height and the wind speed extrapolated to hub height by the log law method. The log law parameters were determined by fitting a logarithmic curve through the average measured wind speeds at the three measurement heights.

The average equivalent wind shear exponent is reported in the following table.

Based on our knowledge about the vegetation in the area of the mast, this value conforms to expected results.

Table 3-4: Average Wind Shear at the Mast

Mast	Period	Wind Shear
2603	November 01, 2013 to October 31, 2014	0.12

3.2.5 *Turbulence Intensity*

Turbulence characterises the gustiness of wind or high frequency changes in wind speed and direction (high turbulence is typical of very irregular wind flows, contaminated by whirls or vortices). Turbulence increases in areas with very uneven terrain and behind obstacles, such as buildings. In wind farms, it interferes with the effective operation of the wind turbines and increases their wear and tear.

The measurement of turbulence is expressed in terms of turbulence intensity, which is the standard deviation of the wind speed divided by the mean wind speed, over a given period. Turbulence intensity is expressed as a percentage. In the present study, the standard deviation and mean speed values are calculated from 1 second wind speed data averaged over a 10 minute period.

Turbulence intensity is more erratic and more difficult to quantify at low wind speeds. As a consequence, only wind speeds in excess of 4 m/s are used to calculate of the turbulence intensity. This threshold is consistent with IEC standards for wind turbine power performance measurements [4].

The turbulence intensity value was calculated with the top anemometer data.

The average turbulence intensity is reported in the next table. This value is considered moderate according to the reference values defined in reference [2][2]. It is expected that turbulence will decrease with height, as the effect of obstacles and surface roughness will diminish.

Table 3-5: Average Turbulence Intensity at the Mast

Mast	Anemometer used	Period	Turbulence Intensity (%)
2603	A1	November 01, 2013 to October 31, 2014	12.0

3.2.6 *50-year recurrence wind speed*

The selected wind turbines Northern power 100 (NPS100) and Emergya Wind Technologies 900 kW (EWT900) are designed to survive a certain level of loading caused by an extreme wind event. Based on the specification provided by the manufacturers, the extreme survival wind speed at hub height is 59.5 m/s (see Appendix B).

At least 7 years of data at the met mast location or a nearby reference station are required. The Gumbel distribution was used to predict the once-in-fifty-year extreme wind speed. The data were extrapolated to hub heights of 37 m (NPS100) and 40 m (EWT900) with a power law exponent of 0.11 suggested for gusts as per Wind Energy Handbook [2] and IEC 61400-1 standard.

In the case of Makkovik project, the met mast has only 18 months of data. Thus, data from Hopedale (AUT) Environment Canada station were used and based on hourly data at 10 metres height. The data cover the period from 2005 to 2014. The 50-year recurrence maximum wind speeds were estimated to be 48.3 m/s at 37 m and 48.7 m/s at 40 m which respect the turbines' specifications.

3.3 Other Climatic Data

3.3.1 *Temperature*

Temperature was measured at a height of 34 m. The following table presents the average monthly and annual temperature measured. The coldest 10-minute temperature recording measured during the data collection period was -32.4℃ in the morning of January 2, 2014.

Table 3-6: Average Monthly and Annual Temperatures

Mast ID	Monthly Air Temperature (°C)												Annual
	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	
2603	-15.6	-16.8	-14.3	-4.5	1.0	8.9	13.0	14.1	7.2	4.7	-3.5	-16.8	-1.8

[2] Low levels of turbulence intensity are defined as values less than or equal to 0.10, moderate levels are between 0.10 and 0.25, and high levels are greater than 0.25. This classification is for meteorological turbulence only; it should not be used in comparison with IEC models. Meteorological turbulence should not be used to establish the wind turbine class.

3.3.2 Air Density

Wind energy is directly proportional to the air density. Consequently, the amount of energy produced by a wind turbine will also be directly proportional to the air density at the turbine location. Air density decreases with increasing temperature, decreasing pressure and increasing altitude.

Based on the measured temperatures and the standard barometric pressure of 101.3 kPa at sea level, the monthly average air densities were calculated. Note that to correct for changes in atmospheric pressure with height, the calculations account for the site elevation. The values were calculated over the entire analysis period reported in Table 2-2.

Table 3-7: Monthly and Annual Average Air Density

Mast ID	Monthly Air Density (kg/m^3)												Annual
	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	
2603	1.35	1.36	1.34	1.30	1.27	1.23	1.22	1.21	1.24	1.25	1.29	1.36	1.31

3.3.3 Power density

Wind speed, wind direction and air density data can be combined to provide information about the average power density at mast location. Wind power density indicates how much energy is available at a given instant for conversion by a wind turbine[3]. For example, strong winds in the winter, when the air is colder and denser, will have a higher power density (i.e. carry more energy) than the same strong winds in the summer. Though power is an instantaneous value, it is calculated as an average over a given period of time.

Tables of the power density distribution per direction and per month were produced at the top anemometer height and are presented below.

At mast 2603, the most powerful winds come from west-southwest to northwest, and appear in winter months. The annual average power density is 637 W/m^2 at 35 m.

Table 3-8: Table of Wind Power Density per Direction, November 1, 2013 to October 31, 2014

Wind Power Density per Direction (W/m^2)															
N	NNE	NE	ENE	E	ESE	SE	SSE	S	SSW	SW	WSW	W	WNW	NW	NNW
417	299	260	397	470	695	354	199	148	287	656	954	886	626	937	585

Table 3-9: Table of Wind Power Density per Month, November 1, 2013 to October 31, 2014

Wind Power Density per Month (W/m^2)												Annual Average
Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	
1339	735	905	610	212	177	249	178	751	547	1011	1106	637

[3] Note that the units "W/m^2" refer to m^2 of rotor swept area.

3.3.4 Icing Events

Icing affects the operation of wind turbines. Icing on any exposed part of the turbine can occur in the form of wet snow (generally associated with temperatures between 0°C to 1°C), super-cooled rain or drizzle (that can occur at temperatures between 0°C to -8°C, but mostly in the upper part of this range), or in-cloud icing (that can occur below - 2°C). Losses during production due to ice occur in several ways:

- Ice accumulation on the blades alters their aerodynamic profile, reducing the power output.

- Nacelle-mounted instruments accumulate ice and give inaccurate readings. The turbine control system may detect a fault condition due to the turbine output being much greater than expected. This expectation is based on the wind speed. As a result, the turbine will be shut down until the ice is removed from the instruments and the turbine is reset.

- Asymmetric icing causes mass or aerodynamic imbalance leading to vibrations. Control systems that sense vibrations will normally shut down when these vibrations occur.

Icing is a complex phenomenon and predicting icing from meteorological conditions is notoriously difficult, requires a good set of observations from a number of meteorology variables, and can be misleading. As no reliable instrument is presently available to detect and quantify icing events for the purpose of estimating their impact on wind energy production, Hatch uses several tests during data quality control to detect icing events: detection of unusual standard deviations or changes with time of wind speeds and directions, comparison of measurements from a heated anemometer and a standard anemometer at the same level, in parallel with the measurement of temperature.

These tests cannot distinguish between the different types of icing, but a rough approximation can be done by utilising the temperature ranges measured during icing events. Therefore, in the following estimate, we will consider two categories: “glaze”, which is assumed to include wet snow, super-cooled rain and drizzle, and “rime ice”, which is assumed to include in-cloud icing and the very low temperature part of super-cooled rain or drizzle. The threshold of -5°C is used to differentiate between rime ice (below -5°C) and glaze (above -5°C).

The following table presents the estimated number of icing events in a month and the type of event assumed to occur in the project area. This estimate is based on the average of icing events detected on the mast during the measurement campaign.

Table 3-10: Estimated Hours of Icing Events, October 25, 2013 to April 30, 2015

	January	February	March	April	May	June	
Hours	6	11	2	52	11	0	
Rime	100%	100%	100%	20%	10%	-	
Glaze	0%	0%	0%	80%	90%	-	
	July	**August**	**September**	**October**	**November**	**December**	**Annual Average**
Hours	0	0	0	4	60	0	146
Rime	-	-	-	0%	10%	-	23%
Glaze	-	-	-	100%	90%	-	77%

4. Long-term Wind Speed at Hub Height

The previous section presented the analysis of the wind regime as it was measured by the met mast installed on the project site. However, to forecast the energy production of a wind power plant, wind data that represent the historical wind conditions at the site are required. Unfortunately, wind resource assessments are generally conducted for a limited number of years, often no more than one or two years, which is not sufficient to capture the year-to-year variability of wind. For example, in North America, the annual average wind speed exhibits a standard deviation of about 6% (or 1σ from a normal distribution) of the long-term average wind speed. Hence, the maximum deviation from the average wind speeds could reach as much as 20% (or 3.3σ). Consequently, it is necessary to translate the measured short-term data into long-term data. This is done through a correlation/adjustment process that makes reference to a meteorological station where historical data are available.

Moreover, when the top anemometers of the met masts are mounted at a lower height than the expected hub height of the wind turbines, the long-term data must also be extrapolated from these anemometer heights to the wind turbine's hub height.

The long-term projection process is presented in the next section and is followed by the extrapolation to hub height.

4.1 Long-term Projection

When required, selecting a reference dataset to perform a long-term correlation and adjustment is determined by the following process:

- A quality assessment of the potential long-term reference stations for the site (history, similarity of the local climate with regards to the meteorology mast climate, etc.);

- A quality assessment of the correlation equations obtained with acceptable long-term reference stations and the measured data for the concurrent period;

- A comparison of the long-term correlation results obtained with all acceptable reference stations;

- A crosscheck of the resulting long-term adjustments with the measured data and the long-term trends at nearby reference stations or at a regional level;

Once the reference dataset is selected, it is used to adjust the met mast data to long-term conditions. This can be achieved either by synthesizing non existing years of data at the met mast site or by applying an adjustment factor to the measured data in order to better reflect the reference period. The process is as follows:

- The measured data from the met mast is correlated with the reference dataset;

- If the correlation parameters meet the synthesis criteria, then data are synthesized at the measurement mast for the complete reference data period; this method is referred to as the Measure-Correlate-Predict (MCP);

- If the criteria are not met but a good correlation can still be obtained with hourly or daily intervals, then the measured dataset is scaled up (or down) to long-term using the reference long-term average wind speed and the correlation equation obtained; this method is referred to as the Long-term Adjustment;

- If no correlation can be clearly established between a reference site and the met mast site, the measured data stay unchanged.

4.1.1 *Selection of reference dataset*

The present section summarises the results of the analysis.

Among the possible set of reference stations, one station was selected and considered suitable for the long-term projection of the data at the met mast. This station is Hopedale monitored by Environment Canada (EC). The location of this station is given in the table below.

Table 4-1: Identification of the Long-term Reference

Name	ID	Instruments Height (m)	Latitude	Longitude	Elevation (m)
Hopedale (AUT)	8502400	10.0	N 55° 27' 00.0"	W 60° 13' 00.0"	11.9

4.1.2 *Long-term Adjustment*

The long-term adjustment consists of:

- Correlating short term data at the met mast with short term data at the reference station;

- Using the obtained linear regression equation, Y = m X + b, where X represents the long-term average wind speed at the reference station and Y is the estimated long-term average at the met mast;

- Applying an adjustment factor (to speed up or scale down) to the met mast short term data in order to obtain an average wind speed equal to the estimated long-term average at met mast (i.e. Y).

For mast 2603, which only displayed 18 months of data recorded, the long-term adjustment method was used for the long-term projection.

The wind speed data of the met mast were correlated to the concurrent wind speed data at the long-term reference station Hopedale. Good correlation results were obtained with daily average values (R^2 greater than or equal to 0.7 is good correlation, above 0.85 is excellent). The results of the correlations are given in the following table. Linear regression equations were used to compare the data, where *m* is the slope of the equation, *b* is the intercept, and R^2 is the coefficient of determination.

Table 4-2: Correlations between Reference Station and met mast Wind Speeds

Reference Station	Met Mast	Correlation Period		Daily Wind Speed Correlations		
		Beginning	End	m	b	R^2
EC Hopedale	**2603**	November 1, 2013	October 31, 2014	1.245	0.9	0.69

The regression equations were then used to estimate the long-term average wind speed at the mast as a function of the long-term wind speed at the reference station. The estimated long-term average at the Hopedale station is 5.4 m/s. It was estimated by averaging all annual averages over the period 2005 to 2014 (except 2011 having a low recovery rate). The results are presented in the following table.

Table 4-3: Long-term Adjustment factor at the met mast

Met Mast	Wind Speed over Correlation Period (m/s)	Long-term Annual Wind Speed (m/s)	Adjustment Factor (%)
2603	7.7	7.6	-1.9%

Finally, the 10-minute measured data recorded at the met mast were scaled by the adjustment factor to reflect the long-term value. In terms of the wind direction data, the one-year dataset for the met mast remained untouched. As a result, the mast has a set of wind speeds and wind directions that are the best estimate of the long-term wind regime.

4.2 Extrapolation to Hub Height

The wind shear exponent, calculated with the measured data, was used to adjust the dataset to hub heights. The results are presented in the following table.

Table 4-4: Estimated Long-term Wind Speed at Hub Heights*

Met Mast	Estimated Long-term Wind Speed at Top Anemometer Height (m/s)	Estimated Long-term Wind Speed at Hub Height (m/s)	
		37 m	40 m
2603	7.6	7.6	7.7

* Estimated using the calculated wind shear

5. Wind Resource Mapping and Projected Energy Production

Met masts provide a local estimate of the wind resource. Met mast locations are chosen based on how representative they are of the project site and in particular for potential wind turbine locations. However, since the number of met masts is usually limited compared to the expected number of wind turbines, it is necessary to build a wind flow map based on these measurements to extend the wind resource assessment to the whole project area.

Wind modeling software, such as MS-Micro and WAsP, are known to produce erroneous wind flows over complex terrain. In this case, Hatch applies a method based on the Ruggedness Index (RIX) to calculate the wind flow for each mast dataset while correcting errors on wind speed[4]. All produced wind flows are then merged by a distance-weighting process. When the RIX correction is not applicable, wind flows are calculated with each mast dataset and simply merged together by a distance-weighting process, without a RIX correction.

Once the wind flow map is built, it is possible to optimise the size and layout of the foreseen wind farm for the project, and then to calculate the projected energy production. When necessary, wind turbine hub heights as well as met mast heights are corrected with the estimated displacement height. This is computed to account for the influence of trees on the wind flow (see section 3.2.4). These corrections result in an effective hub height for each wind turbine.

The wind flow and energy production are calculated with specialised software that require, apart from the met masts long-term data, background maps that contain the information on topography, elevation, roughness lengths (related to the land cover) and potential obstacles. This is also used in conjunction with the wind turbine characteristics. Finally, wind farm losses must be estimated in order to complete the energy estimate.

The first part of this section introduces the information and the methodology used to calculate the wind flow.

The next part will present the optimisation process and the results in terms of energy production.

The software used to map the wind resource and to calculate the energy production include:

- WAsP Issue 11.01.0016 from Risø for wind resource mapping;
- Wind Farmer Issue 4.2.2 from Garrad Hassan for layout optimisation and energy production calculations.

5.1 Background Data

5.1.1 Topography and elevation

The topographic and elevation data come from files provided by the National Topographic Data Base (NTDB).

The contour line interval is 5 m within the project area and 20 m outside.

[4] Bowen, A.J. and N.G. Mortensen (2004). WAsP prediction errors due to site orography. Risø-R-995(EN). Risø National Laboratory, Roskilde. 65 pp.

5.1.2 *Roughness*

The base map for roughness lengths was determined from land cover information included in the NTDB files. This map was then checked and corrected using satellite imagery from Google Earth. Around mast location and wind turbines, pictures and information noted during site visits were also used to check and modify the land cover information. The spatial resolution considered for the roughness lengths is 30 m.

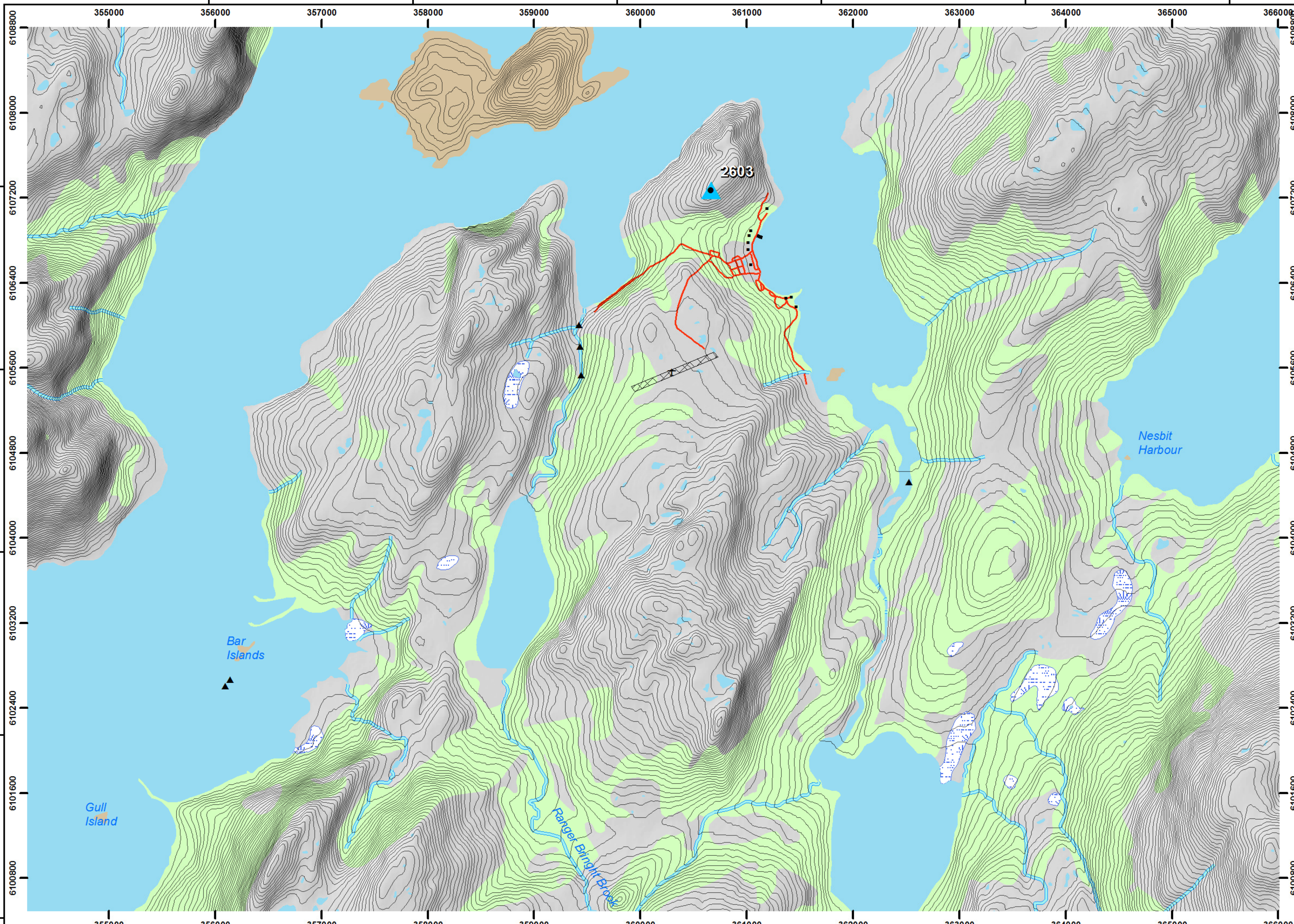
The following table details the roughness lengths used by land cover category.

Table 5-1: Roughness Lengths Categories

Land Cover Type	Roughness Length (m)
Open farmland, high grass	0.04
Forest	0.5
Water	0
Building	0.5

5.1.3 *Background Map*

The background map, showing topography and contour lines is provided on the next page.



Legend

- Met Mast
- Building
- Hazard to navigation: rock in water
- Contour (5m)
- Wharf
- Road
- Watercourse
- Airport
- Island
- Wetland
- Waterbody
- Vegetation

0 0.5 1 2 km

1:40,000

Projection UTMZ21N - NAD83

SOURCE :
Canvec - Natural Resource Canada 1:50 000
Google Earth Pro

NO.	DESCRIPTION	BY	CHK'D	APP'D	DATE

REVISIONS

HATCH

DESIGNED BY DANY AWAD DATE: July06, 2015	DRAWN BY SLADJANA PAVLOVIC DATE: July06, 2015
CHECKED BY DANY AWAD DATE: July06, 2015	

NALCOR

Makkovik - Overview Map

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5.2 Wind Flow Calculation

5.2.1 Terrain Complexity

The wind flow is produced over semi-complex terrain. Wind modeling software, such as MS-Micro (used in Windfarm) and WAsP, are known to produce erroneous wind flows over complex terrain. Depending on the topography, predicted wind speeds can be over or under-estimated at a given location. Errors can reach more than 20% in very complex areas.

In the present case, the complexity of the terrain is considered moderate and its effect on the modelled wind is not considered problematic.

5.2.2 Parameters

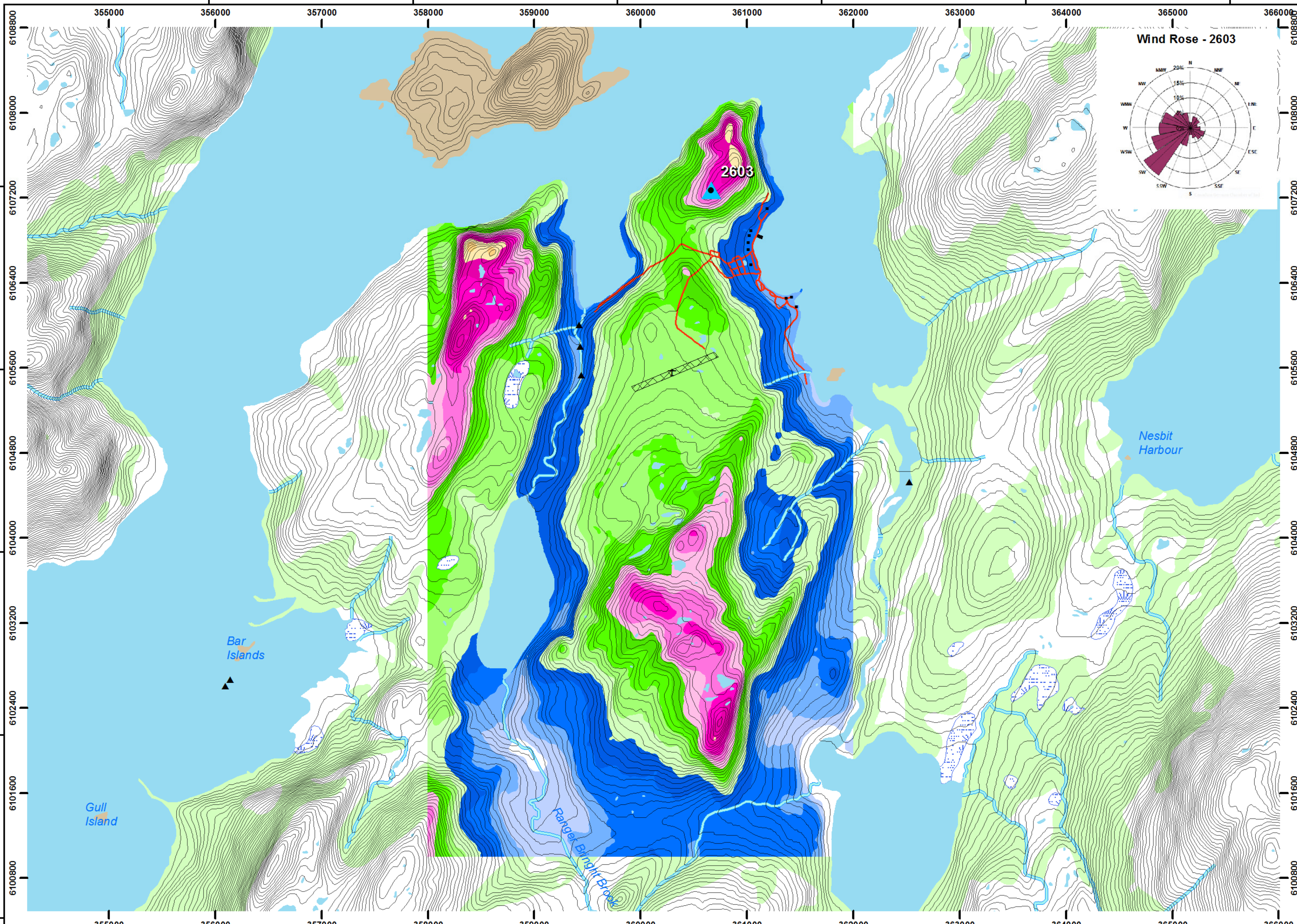
The following parameters were used to calculate the wind flow map.

Table 5-2: Wind Flow Calculation Parameters

Parameter	Value
Wind Resource Grid Spatial Resolution	50 m
Calculation Area	4 km by 7 km
Reference Mast	2603
Reference Height	Top Anemometer Height
Calculation height	37 m
Vertical Extrapolation Method	Based on measured wind shear
Roughness Change Model	WAsP Standard Model

5.2.3 Results

The wind flow map used for layout optimisation and energy production estimates is presented on the next page.



Legend

- Met Mast
- Building
- Hazard to navigation: rock in water
- Contour (5m)
- Wharf
- Road
- Watercourse
- Airport
- Island
- Wetland
- Waterbody
- Vegetation

WindFlow m/s

- < 5
- 5 - 5.25
- 5.25 - 5.5
- 5.5 - 5.75
- 5.75 - 6
- 6- 6.25
- 6.25 - 6.5
- 6.5 - 6.75
- 6.75 - 7
- 7 - 7.25
- 7.25 - 7.5
- 7.5 - 7.75
- 7.75 - 8
- 8 - 8.25
- 8.25 - 8.5
- 8.5 - 8.75
- 8.75 - 9
- 9 - 9.25
- 9.25 - 9.5
- 9.5 <

0 0.5 1 2 km

1:40,000

Projection UTMZ21N - NAD83

SOURCE :
Canvec - Natural Resource Canada 1:50 000
Google Earth Pro

Wind resource map created by Hatch with WAsP 11.01.0016
Height of calculation: 37 m
Spatial resolution of wind resource grid: 50 m
Source file: Makkovik_WF2_2603_GridWRG_37m.asc
Source of data used to create the wind flow:
Topographic data are provided by the Center for Topographic Information (NRCan).
Meteorological data were collected from mast 2603, located 2.5 km on average from the center of the map, between 01/11/2013 and 31/10/2014. Data were controlled by Hatch. Met data were adjusted for long term with reference to station Environment Canada Hopedale (AUT) # 8502400 (reference period 2005-2014).
It is believed that the present map gives a reliable overall picture of the wind resource. However, it is advised to confirm any information obtained from this map at any location by on-site measurements.

NO.	DESCRIPTION	BY	CHK'D	APP'D	DATE

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DESIGNED BY DANY AWAD DATE: July06, 2015	DRAWN BY SLADJANA PAVLOVIC DATE: July06, 2015
CHECKED BY DANY AWAD DATE: July06, 2015	

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Makkovik - Windflow 2

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5.3 Forecasting Energy Production

The layout was initially designed in order to maximise energy production. Turbines were spread out inside the project boundaries to minimise wake effects. The preliminary environmental screening and turbine extreme operating conditions also contributed to set the turbine locations.

5.3.1 Preliminary Turbine Selection

A preliminary turbine selection was performed using Windographer software by comparing the performance of different turbines at the location of the met mast, where the dataset was recorded. The main parameters used for the comparison were the capacity factor of the wind turbine for the site specific conditions as well as the turbine purchase cost. Only turbines that meet the following criteria were considered:

- Site's turbine and turbulence class (IEC class II)
- Extreme wind and weather conditions (operation down to -40℃) The minimum 10-minute temperature recording of -32.4℃ during the monitoring campaign confirms the site conditions are within the operating range of the turbine.
- Turbine capacity ranges from 100 kW to 1,000 kW to meet the community load
- Wind turbine's dimensions and weight versus crane capacity and accessibility

Hub heights of about 40 m to 50 m were used for this preliminary analysis.

Standard losses considered include: 12.5% technical losses and 2% wake losses.

The following table provides a summary of the turbine comparison.

Table 5-3: Windographer Results at the Mast Location

Turbine type	Turbine Class	Hub height (m)	Turbine Capacity (kW)	Mean Energy Output (MWh/yr)	Capacity Factor (%)	Turbine purchase cost ($)
Northern Power NPS100 Arctic	IIA	37	100	296	33.8	325,000
Aeronautica AW/Siva29-250	IIA/IIIA	37	250	668	30.5	656,000
Aeronautica AW/Siva47-500	IB/IIA	47	500	1,671	38.2	1,632,000
EWT DW52-250 (EWT250)	IIA	37	250	1,124	51.3	1,980,000
EWT DW52-500 (EWT500)	IIA	37	500	1,857	42.4	1,990,000
EWT DW52-900 (EWT900)	IIA	40	900	2,566	32.5	2,000,000

The capacity factors listed above in table 5-3 are taken from Windographer and may change as a function of the site's optimized layout and should only be used for turbine comparison.

Due the lack of proven experience in remote arctic conditions, the Aeronautica wind turbine models were discarded from the analysis. Northern Power and EWT wind turbines have

been installed and are operating in similar site conditions in Nome, Alaska for EWT or in Kasigluk, Alaska for Northern Power and were thus further compared as part of the analysis.

The average community load at Makkovik during the project lifetime is around 500 kW. The following table shows the results of the WindFarmer optimization models using the required number of turbines to meet that load. The turbines were ranked based on their capacity factor, energy output and simple payback.

Table 5-4: Preliminary Turbine Selection Results

Turbine type	Number of wind turbine required	Total Capacity (kW)	Gross Energy Output (MWh/yr)	Gross Capacity Factor (%)	Total purchase cost (Million $)	Ranking
Northern Power NPS100 Arctic	**5**	**500**	**2,000**	**45.6**	**1.625**	**2**
EWT250	2	500	2,957	67.5	3.960	4
EWT500	1	500	2,519	57.5	1.990	3
EWT900	**1**	**900**	**3,610**	**45.8**	**2.000**	**1**

* Based on the gross energy output at 30 cents/kWh and the turbine purchase cost only.

Based on information provided by EWT, the 250 kW wind turbine has the same foundation design as the 500 kW and 900 kW machines and nearly the same price ($10,000 difference). Because of the similar turbine costs of the three EWT models, from a financial point of view, the EWT900 becomes the most suitable having the lowest simple payback, and would also benefit from potential lower constructability and BOP cost.

The Northern power NPS100 Arctic can also be considered as potential candidates for the Makkovik project since it is a proven turbine in arctic conditions, and would provide for more redundancy due to number of turbines. The NPS100 has the advantage of being a smaller turbine and would be less difficult from a logistic and crane accessibility stand point.

The NPS100 and EWT900 turbines are two models that meet the wind class of the site and have proven technology for cold and icy environments.

Even though a more detailed turbine selection exercise will be required in later phase of the project, the NPS100 and EWT900 are considered suitable candidate turbines in order to complete the preliminary energy estimates for the potential Makkovik project.

5.3.2 Layout Optimization

The following section shows the WindFarmer modeling results which further refines the energy estimates for the turbines selected at the potential turbine positions and to confirm the capacity factor values. The table below outlines the parameters and constraints assumed to influence optimisation.

Table 5-5: Layout Optimisation Parameters and Constraints

Parameter / Constraint	Value	
Annual Air Density	1.31 kg.m^{-3} at 115 m.a.s.l.	
Turbulence Intensity	12.0% at mast 2603 ***Note**: average value for information, the turbulence intensity is actually entered by wind-speed bins and by direction for energy prediction calculation*	
Exclusion areas	Due to the lack of information in regard to setbacks for wind energy projects in Newfoundland and Labrador, general restriction rules were used: - 500 m from habitations - 100 m from public roads - 50 m from lakes and rivers - 2 km by 1 km buffer zone from the airport track	
WTG Minimum Separation Distance	Elliptical separation: Minimum of 6 rotor diameters on long axis Minimum of 3 rotor diameters on short axis Bearing of long axis: 225 degrees	
WTG Model	EWT900	NPS100 Arctic
WTG Rated Power (kW)	900	100
WTG Rotor Diameter (m)	51.5	20.7
WTG Hub Height (m)	40.0	37.0
WTG Power Curve	See Appendix B	
WTG Thrust Curve	See Appendix B	
Number of WTG's	1	5
Wind Farm Capacity (kW)	900	500
Wake Model	Modified Park Model used for optimisation and Eddy Viscosity Model for final energy calculation as recommended by Garrad Hassan	
Maximum Slope	10 degrees	
Optimization Strategy	Layout designed in order to maximise energy production.	

The project layouts are presented at the end of this section.

The layouts are still considered preliminary. Land restrictions, communication corridors, noise and visual impacts, and other site-specific matters need to be evaluated through a detailed environmental assessment. Available land, road and collection system costs are also issues that will need to be addressed before the site layout can be finalized.

5.3.3 *Energy production*

Once the optimised layout has been produced, the energy production for each wind turbine is calculated. When necessary, wind turbine hub heights as wells as met mast heights are corrected with the estimated displacement height. This is computed to account for the influence of trees on the wind flow. These corrections result in an effective hub height for each wind turbine.

The calculation was executed with the power curves and thrust curves used for the optimisation and presented in Appendix B. The additional losses are described in the next section.

Note that air density is corrected by the software for each turbine location according to its elevation.

The following table is a summary of the estimated energy production. Detailed energy figures are presented per wind turbine on the next page.

Table 5-6: Wind Farm Energy Production Summary

Item	Layout 1 - EWT900	Layout 2 - NPS100 Arctic
WTG Rated Power (kW)	900	100
WTG Rotor Diameter (m)	51.5	20.7
WTG Hub Height (m)	40.0	37.0
Number of Wind Turbines	1	5
Wind Farm Capacity (kW)	900	500
Mean Free Wind Speed across Wind Farm (m/s)	8.4	8.1
Average Wake Losses (%)	0.0	1.1
Energy Production Before Additional Losses* (MWh/yr)	3,610	2,000
Capacity Factor Before Additional Losses* (%)	45.8	45.6
Additional Losses (%)	14.1	13.6
Net Energy Production (P50) (MWh/yr)	**3,102**	**1,728**
Net Capacity Factor (%)	**39.3**	**39.4**

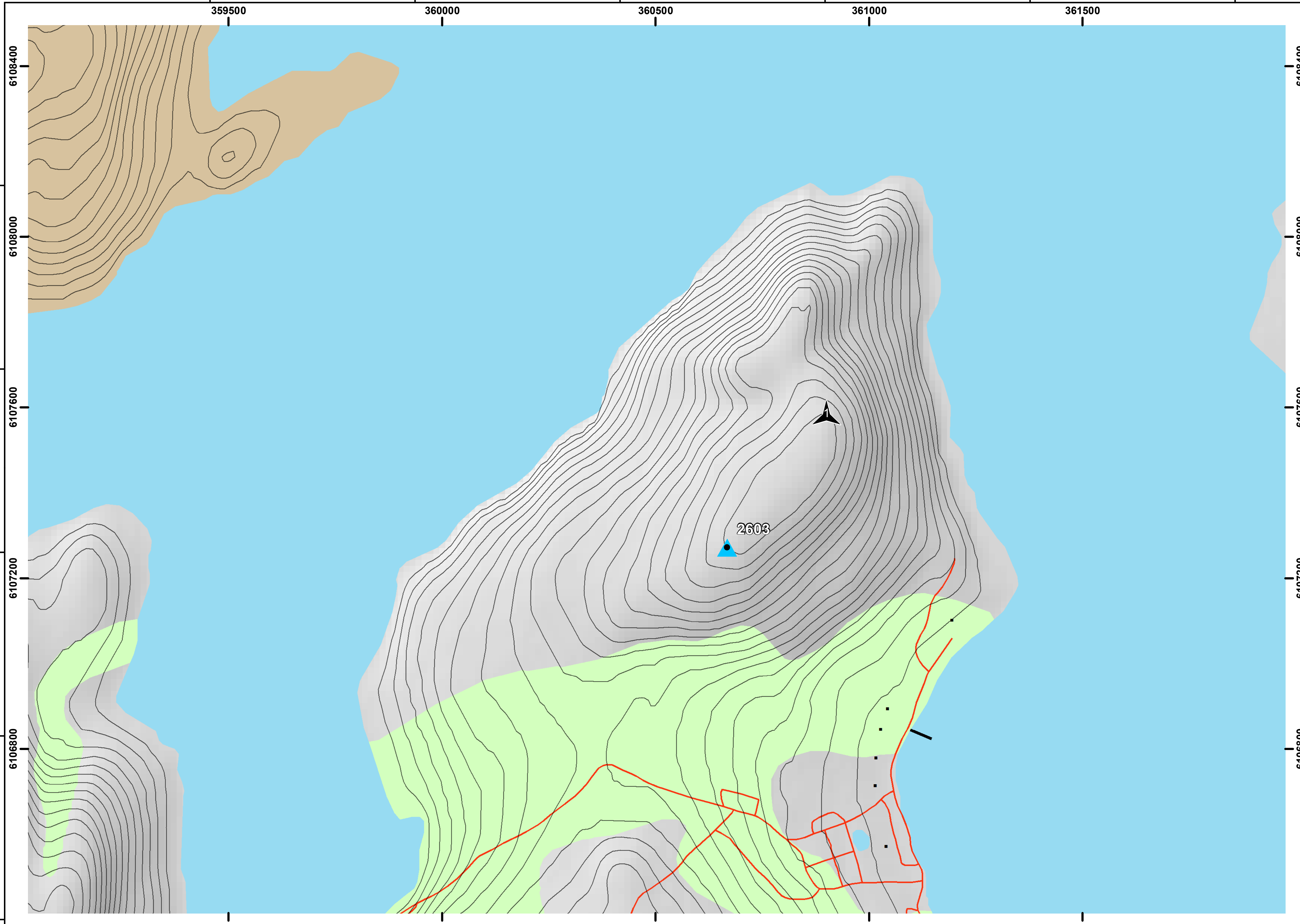
* Includes topographic effect and wake losses

Table 5-7: Forecasted Energy Production at Wind Turbines

Turbine ID	Easting (m)	Northing (m)	Altitude (m)	Mean Free Wind Speed (m/s)	Gross Energy Production* (MWh / Year)	Wake Losses (%)	Gross Energy - Wake* (MWh / Year)	Turbulence Intensity** (%)
Layout 1 - EWT900								
1	360900	6107589	89	8.4	3,610	0.0	3,610	15.2
Layout 2 - NPS100 Arctic								
1	360901	6107480	89	8.1	403	0.6	400	15.9
2	360904	6107561	88	8.3	412	2.6	402	17.0
3	360859	6107604	85	8.2	408	1.8	400	16.8
4	360833	6107669	78	8.0	400	0.6	398	16.4
5	360818	6107763	75	8.1	400	0.1	400	15.8

* Gross energy production includes topographic effect; “Gross energy – Wake” includes topographic effect and wake losses.

** Turbulence Intensity includes ambient turbulence and incident turbulence. The values represent true meteorological turbulence; they should not be compared directly with IEC models and consequently should not be used to establish the wind turbine class.



Legend

- Wind Turbine
- Met Mast
- Building
- Contour (5m)
- Wharf
- Road
- Watercourse
- Island
- Wetland
- Waterbody
- Vegetation

0 125 250 500 m

1:10,000

Projection UTMZ21N - NAD83

SOURCE :
Canvec - Natural Resource Canada 1:50 000
Google Earth Pro

Turbine model: EWT DW52-900
Number of turbines: 1
Site capacity: 900 KW
Turbine rated power: 900 KW
Hub height: 40 m
File reference: Makkovik_WF2_Lay3.txt

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Makkovik - Layout 1

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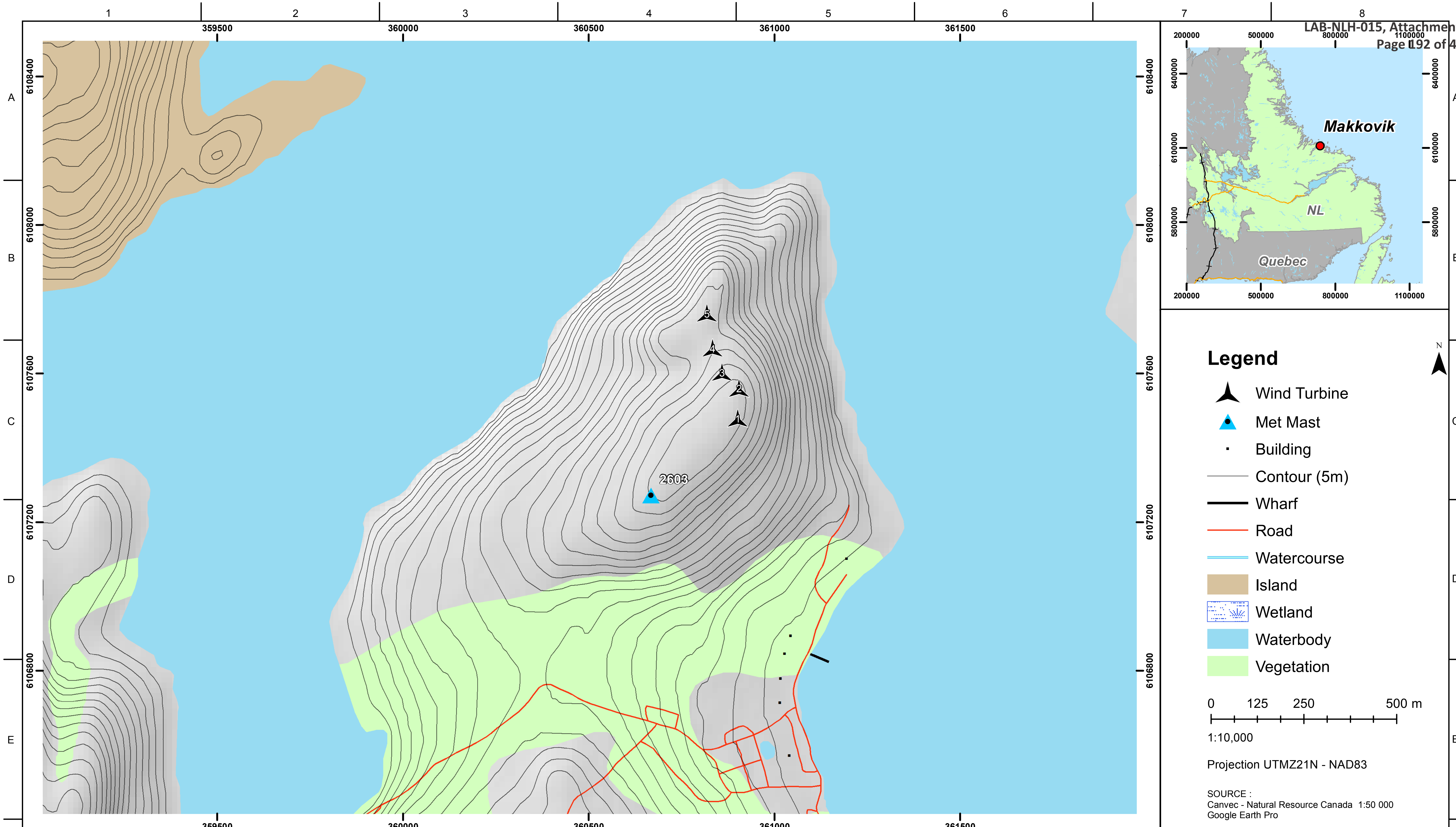

NO.	DESCRIPTION	BY	CHK'D	APP'D	DATE

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Turbine model: Northern Power 100
Number of turbines: 5
Site capacity: 500 KW
Turbine rated power: 100 KW
Hub height: 37 m
File reference: Makkovik_WF2_Lay4.txt

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DATE: August 5, 2015
DRAWN BY SLADJANA PAVLOVIC
DATE: August 5, 2015
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DATE: August 5, 2015

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Makkovik - Layout 2

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5.3.4 Losses

This section provides a description of the estimated losses included in the P50 estimate. These losses include environmental, electrical, availability, turbine performance losses and wake effects. The P50 is defined as the exceedance probability that denotes the level of annual wind-driven electricity generation that is forecasted to be exceeded 50% of the year. Half of the year's output is expected to surpass this level, and the other half is predicted to fall below it. Loss estimates should be reviewed as more detailed information becomes available.

The losses considered are presented in the following table and described hereafter.

Table 5-8: Wind Farm Losses

Loss Category	Loss Type	Losses (%)			
		Layout 1 - EWT900		Layout 2 - NPS100 Arctic	
Environmental	Blade Soiling and Degradation	1.0	4.3	1.0	3.8
	High Wind Hysteresis	0.2		0.2	
	Icing	2.8		2.6	
	Lightning	0.0		0.0	
	Low Temperature Shutdown	0.4		0.0	
Electrical	Collection Network	1.3	3.7	1.3	2.2
	Auxiliary power	2.4		0.9	
Availability	Wind Turbine Availability	5.0	5.8	6.5	7.3
	Collection Network Outage	0.6		0.7	
	Grid Availability	0.2		0.2	
Turbine Performance	Out-of-range Operation	1.0	1.0	1.0	1.0
Wake effects	Internal Wake Effects	0.0	0.0	1.1	1.1
	External Wake Effects	0.0		0.0	
	Total*	**14.1**		**14.6**	

* The total is the cumulated effect of the different losses and not their direct summation

Blade soiling and Degradation refers to the reduction of the blade's aerodynamic performance due to dust and/or insects. It also takes into account the future blade degradation attributed to wear of the blade's surface. The Makkovik project is not situated in a particularly dusty environment. This value is consistent with what is generally observed within the industry.

High wind hysteresis losses are caused by the control loop of the turbine around cut-out wind speed. They depend on the wind turbine design.

These estimations are based on the turbines' control loop specifications and high wind hysteresis simulations. Based on the available wind distribution at the mast, the loss induced by the hysteresis loop is 0.2%.

Icing losses happen in different ways: ice accumulation on blades alter their aerodynamic performance, nacelle-mounted instruments affected by ice give inaccurate readings and induce turbine control system errors, asymmetric icing causes mass or aerodynamic imbalance leading to vibrations that may force control systems to shut down the turbine. Icing can have different impact on the production of the turbine and the effect is site-specific. Some areas will be more affected by freezing rain or glaze ice and other regions are more prone to have rime ice or in-cloud icing.

Icing losses are estimated from the detection of icing events during met masts data quality control and translating the icing events into production losses. The level of ice is considered moderate as compared to other northern sites (up to 10% of icing losses).

Values should be taken with caution since no proven methodology is available and because the effect and characteristics of ice are highly site-specific. The uncertainty associated to these aspects is taken into account in the global uncertainty assessment.

Lightning has the potential to damage the turbine control system but also the blade integrity. Modern wind turbines have protection devices that most of the time allow continuous operation even after a lightning strike. There is however, a small chance that lightning will impact turbine operation. The lightning losses were estimated according to Environment Canada maps[5].

Low temperature shutdown losses depend on the local climate, the turbine design and the control algorithm. In cold climates, turbine shutdowns can be driven by low temperature detection, even if the wind is blowing. According to the manufacturers' specifications, the wind turbines with cold weather package have an operation threshold of - 40°C. The loss is estimated based on the long-term temperature data measured at Hopedale Environment Canada station.

Collection network loss is considered at the interconnection point. It takes into account various elements, including the length of the cables connecting the wind turbines to the substation and the losses in the substation itself. Losses depend on the design of these elements.

These losses have been estimated by Hatch according to previous experiences with similar project size and conditions. They should be confirmed when the design of the collection network is finalized.

Auxiliary power losses account for various subsystems of a wind turbine that require electrical power, such as control systems or heaters. All of these losses are not always

5 http://ec.gc.ca/foudre-lightning/default.asp?lang=En&n=42ADA306-1

accounted for in the power curve. For example, cold packages designed for cold climate wind turbines can require energy even when the turbine is stopped.

Based on Hatch's experience, an estimated value is used to account for the consumption of standard auxiliary systems. Specific losses have been added for the Cold Package system delivered with the wind turbines. They have been estimated by simulation according to the Cold Package specifications of the EWT900 and NPS100 Arctic wind turbines.

Wind turbine availability losses represent the percentage of time over a year that the turbine is unavailable for power production. Losses include regular maintenance time and unexpected turbine shutdowns. A given availability rate is normally guaranteed by utility-scale wind turbine manufacturers such as EWT (95%), but in the case of smaller wind turbines (NPS100), no availability warranty will be offered by the manufacturer.

Based on Hatch's experience on wind farms in similar conditions and technology for isolated sites, Hatch considers the estimate of 6.5% to be adequate for the Project with NPS100 units.

This estimation considers a standard maintenance schedule of 1 day per year per turbine, plus unscheduled repairs and delays due to site accessibility and weather conditions. This is based on information provided by the client that wind turbines will be considered as non-essential grid components and thus deficiencies will be considered as low priority, so that individual units may remain out of service for periods longer than normally considered.

Collection Network Availability: The collection network may be out of service, stopping energy delivery from the turbines to the grid. Collection network outage losses include shutdown time for scheduled maintenance and unexpected outages.

Based on the information provided by the client, the Makkovik based operators will manage the site and are expected to have the skills and manpower required to fix any collection system problem in a timely manner. The presence of a support team onsite has a positive impact on the availability of the collection network.

Grid availability losses depend on the utility distribution system quality and capacity. It represents the percentage of time in a year when the grid is not able to accept the energy produced by the wind turbines.

The value used assumes the wind turbines will be connected to the grid operated by NLH, which is assumed to be well maintained and operated.

Out-of-range Operation losses take into account the aspects usually not covered by the power curve warranty such as turbulence, wind shear and yaw errors. Parameters specific to the Project have been used to perform this loss estimate.

Wake Effect corresponds to the deficit in wind speed downstream of a wind turbine. Several models exist to quantify this effect in terms of induced energy losses. Hatch uses the Eddy Viscosity model which corresponds to a CFD calculation representing the development of the velocity deficit field using a solution of the Navier Stokes equations. Because of higher precision as compared to the Park model and recommendations from WindFarmer, the Eddy Viscosity model is used to assess to the wake of the Project. Wake losses are highly

dependent on the layout, especially regarding the distance between the turbine and the layout's compactness.

One of the input in the wake losses calculation is the thrust curve provided by the turbine manufacturer for the Project turbine model under consideration.

No other wind farm currently exists in the vicinity of the project. In addition, no future wind farm that may impact the Project in terms of wake is planned. Thus, there are no additional wake losses.

6. Conclusions and Recommendations

6.1 Objectives of Analysis

The purpose of this report is to present a full wind resource assessment for the Makkovik site, including the estimation of the forecasted annual energy production.

6.2 Data Quality and Adjustments

The wind data recovery rates at the monitoring site, for the analysis period, exceed industry standards, with recovery rates ranging from 93.5% to 99.3% for the primary anemometers and 98.0% for the primary wind vane.

The measured data were adjusted to long-term through correlation with Environment Canada's Hopedale station, located 77 km away from the project area. The long-term adjustment method was applied since it was considered to be the best method for producing a representative dataset for the expected life of the project.

6.3 Wind Resource

The annual average wind speed at the met mast is a result of the measurements and the long-term adjustment. These wind speeds are summarised in the table below for top anemometer and hub heights.

Table 6-1: Estimated Long-term Wind Speeds

Mast (Measurement Height)	Estimated Long-term Wind Speed at Measurement Height (m/s)	Estimated Long-term Wind Speed at Hub Height (m/s)	
		37 m	40 m
2603 (35 m)	7.6	7.6	7.7

The long-term dataset at the met mast was used to build the wind flow across the project area.

The complexity of the terrain is considered moderate and its effect on the modelled wind is not considered problematic.

6.4 Forecasted Energy Production

The preliminary turbine selection analysis specified two suitable turbine models: EWT900 and NPS100 Arctic. These models were proven to be best in class for cold and icy environments and suitable for wind-diesel generation in remote community.

The main results of the energy production modeling are summarised in the table below.

Table 6-2: Forecasted Annual Energy Production

Item	Layout 1 - EWT900	Layout 2 - NPS100 Arctic
WTG Rated Power (kW)	900	100
Number of Wind Turbines	1	5
Wind Farm Capacity (kW)	900	500
Annual Net Energy Production (MWh/yr)	**3,102**	**1,728**
Net Capacity Factor (P50) (%)	**39.3**	**39.4**

There remains some uncertainty regarding loss estimates, which should be reassessed as more information becomes available, particularly in relation to warranty contracts and maintenance schedules. Note that the Annual Net Energy Production represents the total forecasted energy production by the wind turbines. The effective energy production used to displace fuel will be a bit lower and vary depending on the chosen layout scenario (type and number of wind turbines), timewise power load and wind resource.

6.5 Recommendation

It should be noted that a number of additional studies and more detailed analysis will be required to refine and validate the turbine selected, the turbine position, the energy and losses.

The integration optimization report will show which turbine model is considered optimal for the Makkovik site based on energy cost, control capabilities and logistics and provide recommendations for further analysis and studies prior to implementation.

References

[1] International Energy Agency Programme, *Recommended practices for wind turbine testing and evaluation – Task 11: Wind Speed Measurement and Use of Cup Anemometer*, 1999

[2] National Renewable Energy Laboratory, *Wind Resource Assessment Handbook*, 1999

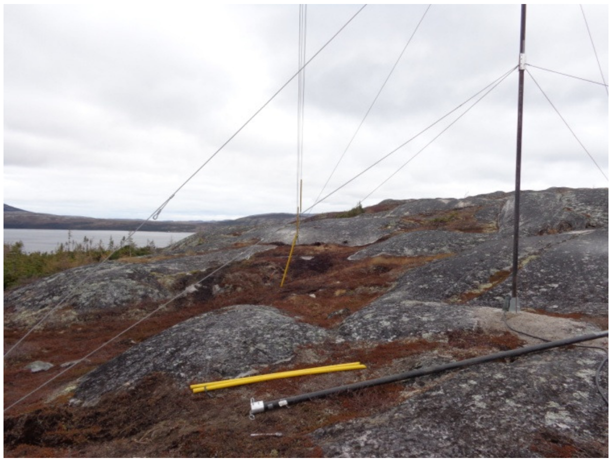
[3] International Electrotechnical Commission, *Wind Turbines - Part 1: Design Requirements*, IEC 61400-1, Ed. 3, 2005-08.

[4] International Electrotechnical Commission, *Wind Turbines - Part 12-1: Power performance measurements of electricity producing wind turbines*, IEC 61400-12-1, Ed. 1, 2005.

[5] A Practical Guide to Developing a Wind Project, *Wind Resource Assessment*, 2011

Appendix A

Views at Mast Site



View Facing North

View Facing East

View Facing South

View Facing West

Figure – A1: Views from Base of Mast 2603

Appendix B

Wind Turbine Data

EWT DW52-900

The power curve and the thrust curve were provided to Hatch by Emergya Wind Technologies.

Table – B1: EWT Wind Turbine Performance Curves

Rotor Diameter: 51.5 m	Hub Height: 40.0 m	Air Density: 1.225 kg.m^{-3}	Turbulence Intensity: N/A
Wind Speed at Hub Height (m/s)	**Electrical Power (kW)**	**Wind Speed at Hub Height (m/s)**	**Thrust Coefficients**
0	0	0	0.000
1	0	1	0.000
2	0	2	0.000
3	7	3	0.866
4	30	4	0.828
5	69	5	0.776
6	124	6	0.776
7	201	7	0.776
8	308	8	0.753
9	439	9	0.722
10	559	10	0.692
11	698	11	0.613
12	797	12	0.516
13	859	13	0.441
14	900	14	0.368
15	900	15	0.296
16	900	16	0.241
17	900	17	0.199
18	900	18	0.168
19	900	19	0.143
20	900	20	0.124
21	900	21	0.109
22	900	22	0.096
23	900	23	0.085
24	900	24	0.075
25	900	25	0.067

NPS100

The power curve and the thrust curve were provided to Hatch by Northern Power.

Table – B2: NPS100 Wind Turbine Performance Curves*

Rotor Diameter: 20.7 m	Hub Height: 37.0 m	Air Density: 1.225 kg.m^{-3}	Turbulence Intensity: N/A
Wind Speed at Hub Height (m/s)	**Electrical Power (kW)**	**Wind Speed at Hub Height (m/s)**	**Thrust Coefficients**
0	0	0	0
1	0	1	0
2	0	2	0
3	0	3	0
4	3.7	4	1.072
5	10.5	5	0.963
6	19.0	6	0.866
7	29.4	7	0.820
8	41.0	8	0.754
9	54.3	9	0.687
10	66.8	10	0.616
11	77.7	11	0.548
12	86.4	12	0.491
13	92.8	13	0.436
14	97.3	14	0.391
15	100.0	15	0.347
16	100.8	16	0.316
17	100.6	17	0.286
18	99.8	18	0.261
19	99.4	19	0.239
20	98.6	20	0.222
21	97.8	21	0.206
22	97.3	22	0.194
23	97.3	23	0.184
24	98.0	24	0.175
25	99.7	25	0.167

* Power curve of the Northern Power 100 – standard model

Gilles Boesch
GB:gb

	Emergya Wind Technologies BV
	Engineering

Category:	Specification	Page 1 / 11
Doc code:	S-1000920	

Created by:	JT	Creation Date:	24-07-09
Checked by:	MB	Checked Date:	24-07-09
Approved by:	TY	Approved Date:	05-04-11

Title:

Specification

DIRECTWIND 52/54*900 Technical Specification

Revision	Date	Author	Approved	Description of changes
02	02-03-12	MB	TY	Format, minor text, blades, options
01	28-11-11	LE	TY	Corrections and drawings
-	-	-	-	-
-	-	-	-	-
-	-	-	-	-
-	-	-	-	-

Emergya Wind Technologies BV
Building 'Le Soleil' - Computerweg 1 - 3821 AA Amersfoort - The Netherlands
T +31 (0)33 454 0520 - F +31 (0)33 456 3092 - www.ewtinternational.com

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1 Introduction

This document provides a technical overview of the *DIRECTWIND* 52/54*900 Wind Turbine designed for the IEC class II/III application. It is to be read in conjunction with document S-1000921 “Directwind 52/54*900 Electrical Specification”.

2 Technical Description

The *DIRECTWIND* 52/54*900 is a direct-drive, variable speed, pitch regulated, horizontal axis, three-bladed upwind rotor wind turbine.

The gearless direct-driven synchronous generator operates at variable speed. This is made possible by an actively controlled AC-DC-AC IGBT power converter connected to the grid. Benefits of this design are low maintenance, constant power output at wind speed above rated, and relatively low structural loads compared to constant-speed stall-controlled or constant-speed pitch-controlled wind turbines.

The generator is fully integrated into the structural design of the turbine, which allows for a very compact nacelle design. The drive-train makes use of only one main bearing, whereas classic designs have separately supported main shaft, gearbox and generator. All dynamically loaded interfaces from the blades to the foundation are sturdy flange connections with machined surfaces, and high tensile steel pre-stressed bolt connections are used.

2.1 Operation and safety system

The turbine operates automatically under all wind conditions and is controlled by an industrial PLC (Programmable Logic Controller). The cut-in wind speed is approximately 3m/s. When the rotational speed reaches the cut-in threshold, the power converter begins to deliver power to the grid.

The power converter controls the generator power output and is programmed with a power set-point versus rotor speed curve. Below rated wind speed the power output is controlled to optimise rotor speed versus aerodynamic performance (optimum λ-control). Above rated wind speed the power output is kept constant at rated value by PD-controlled active blade pitching.

The dynamic responses of the drive train and power controller are optimised for high yield and negligible electrical power fluctuations. The variable speed rotor acts as a flywheel, absorbing fluctuating aerodynamic power input. The turbine controllers are located in the rotor hub and the tower base (with remote IO in the nacelle) and carry out all control functions and safety condition monitoring. In the case of a fault, or extreme weather conditions, the turbine is stopped by feathering of the blades to vane position (blades swivelled to 90^0 with respect to rotor's rotational plane). In case of power loss, an independent battery backup system in each blade ensures the blades are feathered.

In the case of less serious faults which have been resolved, or when extreme weather conditions have passed, the turbine restarts automatically to minimise downtime.

2.2 Generator

The multiple-pole, direct-drive generator is directly mounted to the hub. The stator is located in the non-moving outer ring and the wound pole, separately excited rotor rotates on the inner ring.

The generator is designed such that all aerodynamic forces are directly transferred to the nacelle construction without interfering with the generator-induced loads.

2.3 Power Converter

The power converter is an AC-DC-AC IGBT active switching converter. It controls the generator to operate in its optimum range, and maintains power quality to the grid. The inverter can produce unity power factor (cosΦ=1) to the grid under all load conditions. Power factor is also controllable within limits.

2.4 Rotor

The rotor is a three bladed construction, mounted up-wind of the tower. Rotational speed is regulated by active blade adjustment towards vane position. Blade pitch is adjusted using an electric servomotor on each of the blades.

Each blade has a complete, fully independent pitch system that is designed to be fail-safe. This construction negates the need for a mechanical rotor brake. The pitch system is the primary method of controlling the aerodynamic power input to the turbine.

At below rated wind speed the blade pitch setting is constant at optimum aerodynamic efficiency. At above rated wind speed the fast-acting control system keeps the average aerodynamic power at the rated level by keeping the rotor speed close to nominal, even in gusty winds.

The rigid rotor hub is a nodular cast iron structure mounted on the main bearing. Each rotor blade is connected to the hub using a pre-stressed ball bearing. It is sufficiently large to provide a comfortable working environment for two service technicians during maintenance of the pitch system, the three pitch bearings and the blade root from inside the structure.

2.5 Rotor blade set

The rotor blades are made of fibreglass-reinforced epoxy. The aerodynamic design represents state-of-the-art technology and is based on a pitch-regulated concept. No extenders are used and the aerodynamic design is optimal for this rotor diameter.

2.6 Main bearing

The large-diameter main bearing is a specially designed three row cylindrical roller bearing. The inner non-rotating ring is mounted to the generator stator. The outer rotating ring is mounted between the hub and generator rotor. The bearing takes axial and radial loads as well as bending moments. Entrance to the hub is through the inner-bearing ring. The bearing is greased by a fully automatic lubrication system controlled by the turbine PLC.

2.7 Nacelle

The nacelle is a compact welded construction which houses the yaw mechanism, a service hoist and a control cabinet. Both the generator and the tower are flanged to the nacelle. The geometry of the construction assures an ideal transfer of loads to the tower and, with the absence of a shaft and gearbox, results in a simple design ensuring easy personnel access.

2.8 Yaw system

The yaw bearing is an internally geared ring with a pre-stressed four point contact ball bearing. Electric planetary gear motors yaw the nacelle. The yaw brake is passive and is based on the friction of brake pads sitting directly on the bearing ring, keeping the yaw system rigid under most loading conditions.

2.9 Tower

The nacelle assembly is supported on a tubular steel tower, fully protected against corrosion. The tower allows access to the nacelle via a secure hinged access door at its base. The tower is fitted with an internal ladder with safety wire and optional climb assistance, rest platforms and lighting. Standard hub heights are 35, 40, 50 and 75 metres.

2.10 Anchor

The turbine is supported by a concrete foundation. The connection to this foundation is provided by means of a cast-in tube or rod anchor.

2.11 Control System

2.11.1 Bachmann PLC

The M1 controller perfectly combines the openness of a PC-based controller with the reliability of industrial hardware platforms. Designed to withstand the toughest ambient conditions it guarantees error-free use over long periods of time.

A modern system architecture designed for consistent network-capability permits the easy integration of the M1 into the environment of the controller and system peripherals. Real-time ethernet permits the real-time networking of the controllers, and the support of all standard Fieldbus systems permits the connection of standard external components.

2.11.2 DMS

DIRECTWIND Monitoring System – EWT's proprietary HMI featuring local monitoring and control at the turbine, integrated into a remote-access SCADA. DMS offers individual turbine control and total park monitoring and data logging from your Wind Turbine, Wind Park or internet access point.

2.12 Earthing and lightning protection

The complete earthing system of the wind turbine incorporates:

1. Protective earthing:
   A PE connection ensures that all exposed conductive surfaces are at the same electrical potential as the surface of the Earth, to avoid the risk of electrical shock if a person touches a device in which an insulation fault has occurred. It ensures that in the case of an insulation fault (a "short circuit"), a very high current flows, which will trigger an over-current protection device (fuse, circuit breaker) that disconnects the power supply.

2. Functional earthing:
   Earthing system to minimize and/or remove the source of electrical interference that can adversely affect operation of sensitive electrical and control equipment.

   A functional earth connection serves a purpose other than providing protection against electrical shock. In contrast to a protective earth connection, the functional earth connection may carry electric current during the normal operation of the turbine.

3. Lightning protection:
   To provide predictable conductive path for the over-currents in case of a lightning strike and electromagnetic induction caused by lightning strike and to minimize and/or remove dangerous situations for humans and sensitive electrical equipment.

Since the mechanical construction is made of metal (steel), all earthing systems are combined.

2.13 Options

The following options are available:

- Cold climate operation (rated for operation down to -40°C)
- Ice detection and/or prevention system
- Aviation lights
- Shadow flicker prevention
- Low Voltage Ride-through (LVRT)
- Service lift (75m tower only)
- G59 protection relay

3 Technical Data

Where data are separated by "/" this refers to the respective rotor diameter (52 / 54 m).

3.1 Wind and Site Data

Wind class	II / III according to IEC 61400 – 1
Max 50-year extreme	59.5 / 52.5 m/s
Turbulence class	A (I_{15} = 0.16)
Maximum flow inclination (terrain slope)	8°
Max ann. mean wind speed at hub height	8.5 / 7.5 m/s
Nominal air density	1.225 kg/m³

3.2 Operating Temperature

	Standard	Cold Climate
Min ambient operating	-20°C	-40°C
Max ambient operating	+40°C	+40°C

3.3 Cooling

Generator cooling	Air cooled
Converter cooling	Water or air cooled (configuration-dependent)

3.4 Operational Data

Cut in wind speed	3 m/s
Cut out wind speed	25 m/s
Rated wind speed	14 / 13.5 m/s
Rated rotor speed	26 rpm
Rotor speed range	12 to 33 rpm
Power output	900kW
Power factor	1.0 (adjustable 0.95 lagging to 0.95 leading) Measured at LV terminals

3.5 Rotor

Diameter	52 / 54 m
Type	3-Bladed, horizontal axis
Position	Up-wind
Swept area	2,083 / 2,290 m²
Power regulation	Pitch control; Rotor field excitation
Rotor tilt angle	5°

3.6 Blade Set

Type	PMC 24.5 / 25.8
Blade length	24.5 / 25.8 m
Chord at 22.0 m	0.879 m (90% of 24.5m blade radius)
Chord at 23.5 m	0.723 m (90% of 25.8m blade radius)
Chord Max at 5.5 m	2.402 m
Aerodynamic profile	DU 91, DU 98 and NACA 64618
Material	Glass reinforced epoxy
Leading edge protection	PU coating
Surface colour	Light grey RAL 7035
Twist Distribution	11.5^0 from root to 5.5m then decreases linearly to 0.29^0, then non-linearly to 0^0

3.7 Transmission System

Type	Direct drive
Couplings	Flange connections only

3.8 Controller

Type	Bachmann PLC
Remote monitoring	DIRECTWIND Monitoring System, proprietary SCADA

3.9 Pitch Control and Safety System

Type	Independent blade pitch control
Activation	Variable speed DC motor drive
Safety	Redundant electrical backup

3.10 Yaw System

Type	Active
Yaw bearing	4 point ball bearing
Yaw drive	3 x constant speed electric geared motors
Yaw brake	Passive friction brake

3.11 Tower

Type	Tapered tubular steel tower
Hub height options	HH = 35, 40, 50, 75 m
Surface colour	Interior: White RAL 9001, Exterior: Light grey RAL 7035

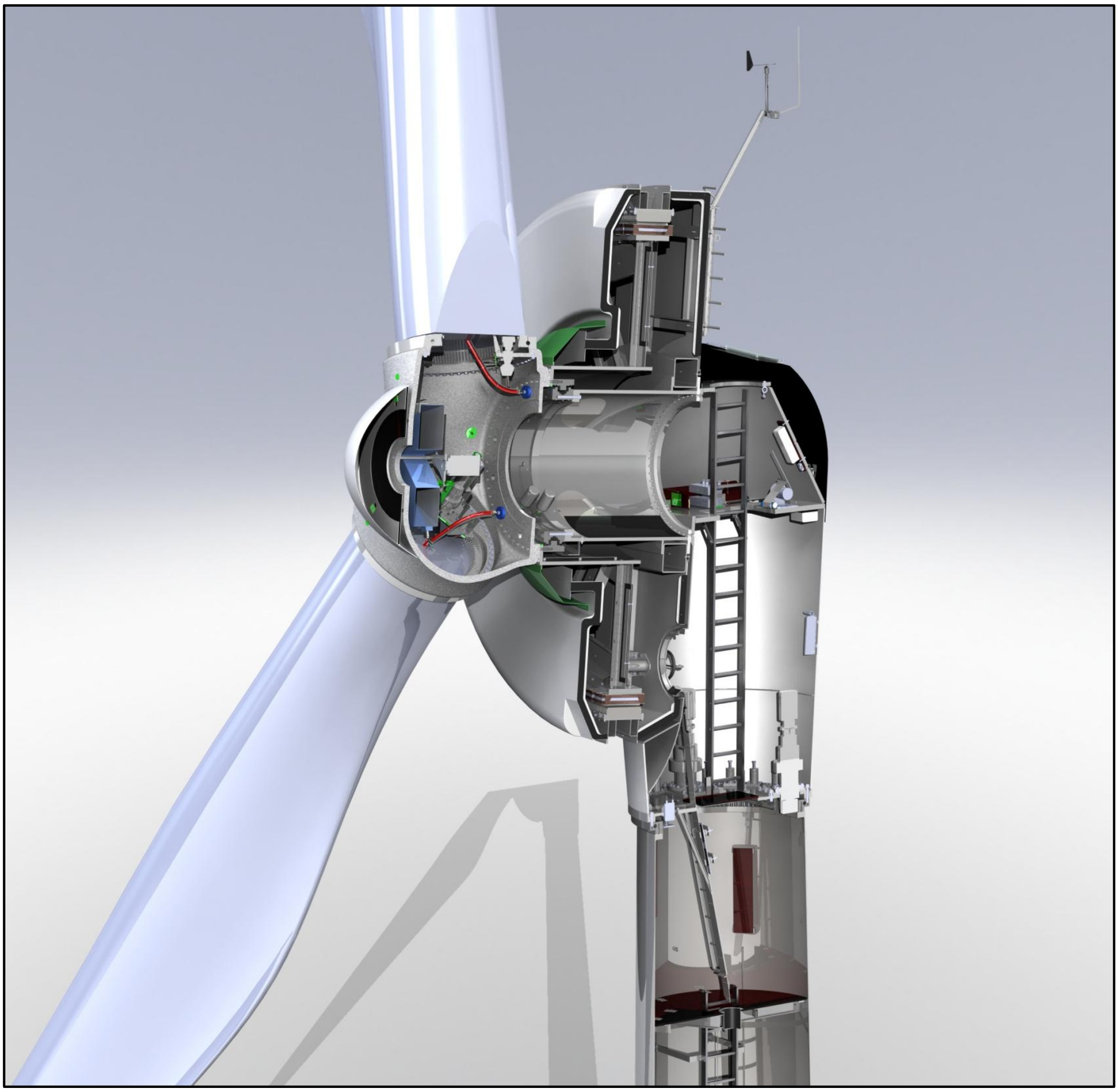
3.12 Mass Data

Hub	9,303 kg
Blade – each	1,919 / 1,931 kg
Rotor assembly	15,060 / 15,096 kg
Generator	30,000 kg
Nacelle assembly	10,000 kg
Tower HH35	28,300 kg
Tower HH40	34,000 kg
Tower HH50	46,000 kg
Tower HH75	86,500 kg

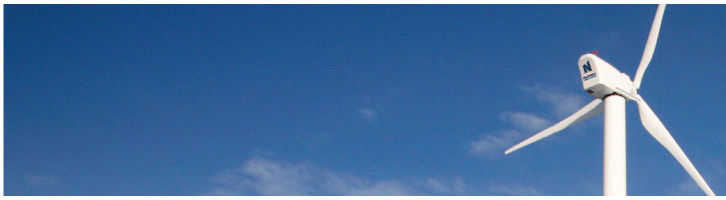
3.13 Service Brake

Type	Maintenance brake
Position	At hub flange
Calipers	Hydraulic 1-piece

APPENDIX 1: 3D image of main turbine components

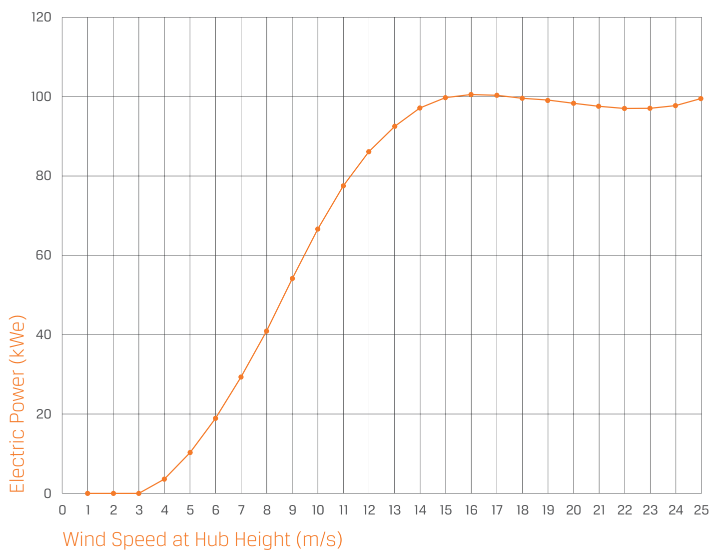


Specifications



Northern Power® 100

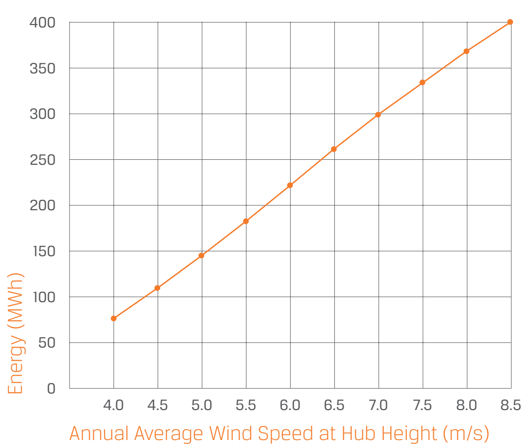
Power Curve: 21-Meter Rotor Standard Air Density (1.225 kg/m³)



Wind Speed (m/s)	Power (kWe)	Wind Speed (m/s)	Power (kWe)
1	0	14	97.3
2	0	15	100.0
3	0	16	100.8
4	3.7	17	100.6
5	10.5	18	99.8
6	19.0	19	99.4
7	29.4	20	98.6
8	41.0	21	97.8
9	54.3	22	97.3
10	66.8	23	97.3
11	77.7	24	98.0
12	86.4	25	99.7
13	92.8		

1 m/s = 2.24 mph

Annual Energy Production*: 21-Meter Rotor Standard Air Density, Rayleigh Wind Speed Distribution



Average Annual Wind Speed (mph)	Average Annual Wind Speed (m/s)	Annual Energy Output (MWh/yr)
8.9	4.0	77
10	4.5	110
11	5.0	145
12	5.5	183
13	6.0	222
15	6.5	260
16	7.0	298
17	7.5	334
18	8.0	368
19	8.5	400

*Annual energy production estimates assume standard conditions, 100% availability and no losses.

Northern
POWER SYSTEMS

Specifications

GENERAL CONFIGURATION	DESCRIPTION
Model	Northern Power® 100
Design Class	IEC IIA (air density 1.225 kg/m^3, average annual wind below 8.5 m/s, 50-yr peak gust below 59.5 m/s)
Design Life	20 years
Hub Height	37 m (121 ft) / 30 m (98 ft)
Tower Type	Tubular steel monopole
Orientation	Upwind
Rotor Diameter	21 m (69 ft)
Power Regulation	Variable speed, stall control
Certifications	UL1741, UL1004-4, CSA C22.2 No.107.1-01, CSA C22.2 No. 100.04, and CE compliant

PERFORMANCE	DESCRIPTION (standard conditions: air density of 1.225 kg/m^3, equivalent to 15°C (59°F) at sea level)
Rated Electrical Power	100 kW, 3 Phase, 480 VAC, 60/50 Hz
Rated Wind Speed	14.5 m/s (32.4 mph)
Maximum Rotation Speed	59 rpm
Cut-In Wind Speed	3.5 m/s (7.8 mph)
Cut-Out Wind Speed	25 m/s (56 mph)
Extreme Wind Speed	59.5 m/s (133 mph)

WEIGHT	DESCRIPTION
Rotor (21-meter) & Nacelle (standard)	7,200 kg (16,100 lbs)
Tower (37-meter)	13,800 kg (30,000 lbs)

DRIVE TRAIN	DESCRIPTION
Gearbox Type	No gearbox (direct drive)
Generator Type	Permanent magnet, passively cooled

BRAKING SYSTEM	DESCRIPTION
Service Brake Type	Two motor-controlled calipers
Normal Shutdown Brake	Generator dynamic brake and two motor-controlled calipers
Emergency Shutdown Brake	Generator dynamic brake and two spring-applied calipers

YAW SYSTEM	DESCRIPTION
Controls	Active, electromechanically driven with wind direction/speed sensors and automatic cable unwind

CONTROL/ELECTRICAL SYSTEM	DESCRIPTION
Controller Type	DSP-based multiprocessor embedded platform
Converter Type	Pulse-width modulated IGBT frequency converter
Monitoring System	SmartView remote monitoring system, ModBus TCP over ethernet
Power Factor	Set point adjustable between 0.9 lagging and 0.9 leading
Reactive Power	+/- 45 kVAR

NOISE	DESCRIPTION
Apparent Noise Level	55 dBA at 30 meters (98 ft)

ENVIRONMENTAL SPECIFICATIONS	DESCRIPTION
Temperature Range: Operational	-20°C to 50°C (-4°F to 122°F)
Temperature Range: Storage	-40°C to 55°C (-40°F to 131°F)
Lightning Protection	Receptors in blades, nacelle lightning rod and electrical surge protection
Icing Protection	Turbine designed in accordance with Germanischer Lloyd Wind Guidelines Edition 2003

All Specifications subject to change without notice.

NPS100SS-2222011-US

Appendix D:
Wind Resource Assessment Report – Cartwright

Project Report

November 15, 2015

Newfoundland and Labrador Hydro
Cartwright Wind Project

Distribution

Trevor Andrew – NLH
Asim Haldar – NLH
Bob Moulton – NLH
Timothy Manning – NLH
Terry Gardiner – NLH
Louis Auger – Hatch
Dany Awad – Hatch
Ève-Line Brouillard – Hatch

Final Wind Resource Assessment Report

Safety ● Quality ● Sustainability ● Innovation

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In preparing this report, various assumptions and forecasts were made by Hatch concerning current and future conditions and events. These assumptions and forecasts were made using the best information and tools available to Hatch at the time of writing this report. While these assumptions and forecasts are believed to be reasonable, they may differ from what actually might occur. In particular, but without limiting the foregoing, the long-term prediction of climatological data implicitly assumes that the future climate conditions will be identical to the past and present ones. Though it is not possible to definitively quantify its impact, the reality of the climate change is recognised by the scientific community and may affect this assumption.

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DOCUMENT HISTORY

Revision	Date	Description
1	August 31, 2015	Final Version
2	November 15, 2015	Few edits based on comments from NLH on October 30, 2015 – Final Version

EXECUTIVE SUMMARY

In order to assess the potential of Cartwright site for wind power development, a wind resource assessment (WRA) was completed. The site is located near the community of Cartwright, Newfoundland and Labrador, Canada. The site was equipped with one met mast that is described in the table below.

Met Mast	Installation Date	Top Anemometer Height (m)	Elevation (m)	Data Collection* Starts…	Data Collection* Ends…
2605	November 5, 2013	35.0	57	November 5, 2013	April 30, 2015

* A 12 month period is selected to estimate the annual energy production

In the analysis, the quality control process demonstrated that the data recovery rates exceeded 95 % on all instruments which meets industry standards for wind measurement campaign. Erroneous or unreliable data were replaced with available redundant data from instruments on the same met mast since these are considered to be equivalent wind measurements.

The **wind speed** measured at the mast is **6.5 m/s** in average. The **winds are dominant from southwest** across the site.

The wind **turbulence intensity** observed at the site is generally **moderate**.

Given the land cover and topography at the mast the **wind shear exponent**, equal to **0.11**, is consistent with the expected value.

Met Mast	Period	Annual Average of Measured Wind Speed* (m/s)	Annual Average of Measured Turbulence Intensity* (%)	Annual Wind Shear
2605	December 1, 2013 to November 30, 2014	6.5	14.4	0.11

** at Top Anemometer Height*

During the data quality control process, icing events were detected on anemometers and wind vanes. **Icing** occurred **3.1% of the time** at the site. Given the site elevation and the temperatures associated with these events, it is likely that about 82% of these events were caused by freezing rain and about 18% were caused by rime ice. Icing events mainly occurred during the month of November.

Temperature data were collected at the mast. The monthly averages range from **-15.0°C** in December to **15.1°C** in July, with an **annual average** of **-0.6°C**. The coldest 10-minute temperature recording during the data collection period was -30.0°C.

The **air density** was calculated at the mast according to the elevation and the local temperature. The annual value is **1.30 kg/m^3**.

The annual average power density is **467 W/m²**. The most powerful winds come from southwest to west-northwest across the site.

In order to estimate the **long-term wind regime** at the site, several potential **reference stations** with historical data were selected.

The **Cartwright station** monitored by Environment Canada, located 4 km away from the potential wind farm site, was selected as the reference station for the long-term extrapolation of the data. The reference station data were then correlated to met mast 2605 and used to translate the short-term data into long-term estimates.

The long-term estimates were then extrapolated from measurement height to hub heights.

Met Mast	Period	Estimated Long-term Wind Speed at Top Anemometer Height (m/s)	Estimated Long-term Wind Speed at Hub Height (m/s) at 37 m / 40 m
2605	December 1, 2013 to November 30, 2014	7.0	7.3 / 7.3

The wind resource estimated at the mast was used to compute the wind flow across the project area. The wind flow was calculated with WAsP 11.01.0016 software, which is an appropriate model for the Cartwright project area which exhibits a moderate terrain complexity.

This wind flow was used to optimise the layout of the potential wind farm and to estimate the energy production with WindFarmer software.

A preliminary turbine selection analysis was completed and two turbine models were selected: Emergya Wind Technologies 900 kW (EWT900) and Northern power 100 (NPS100 Arctic). These models have proven technology in cold and icy environments and are suitable for wind-diesel generation in remote community.

A wind farm layout optimisation was completed taking in consideration energy production, information from the preliminary environmental screening and turbine extreme operating condition.

The main results of the energy production modeling are presented below. Additional losses include blade soiling, icing, collection network losses, auxiliary power consumption, wind turbines availability, high wind hysteresis, low temperature shutdown, collection network outage and grid availability.

Layout	Wind Farm Capacity (kW)	Net Energy Production (MWh/year)	Net Capacity Factor (%)	Wake Losses (%)	Additional Losses (%)
Layout 1 - EWT900	900	2,898	36.7	0.0	14.2
Layout 2 - NPS100 Arctic	500	1,559	35.6	4.0	14.0

Other energy production scenarios will be covered under separate portion of the wind penetration report.

1. Introduction

Hatch has been mandated by Newfoundland and Labrador Hydro (NLH) to carry out a wind resource assessment (WRA) for a potential wind farm project, located 3 kilometres east of the community of Cartwright, Newfoundland and Labrador, Canada.

The site was instrumented with one meteorological ("met") mast. The installation was completed on November 5, 2013. The mast was equipped with sensors at several heights to measure wind speed, wind direction and temperature. The analysed data cover a total measurement period of one year.

The second section of this report presents an overview of the site and the measurement campaign.

The third section presents the main characteristics of the wind climate.

The fourth section details the process used to translate the measured short-term data into long-term data.

The fifth section presents the methodology used to obtain the wind flow map over the project area. The wind flow map optimises the wind farm layout and helps determine monthly and annual energy production estimates. The key resulting values of these estimations are provided, including a description of the losses considered in the net energy calculation.

2. General Information

This section summarises general information about the site, the meteorological (met) mast installed and the measurement campaign.

2.1 Site Description

2.1.1 Site Overview

The community of Cartwright is located on the eastern side of the entrance to Sandwich Bay along the southern coast of Labrador. The surroundings of the community consists mainly of gently rolling hills with an average elevation of 120 m above sea level.

Figure 2-1: Typical Landscape at the Cartwright Area

2.1.2 Mast Location

The location of met mast 2605 was chosen with agreement between Hatch and NLH. Hatch proceeded with the installation of the mast and followed industry standards [1].

Table 2-1 provides a description of the mast, including the exact coordinates and the elevation.

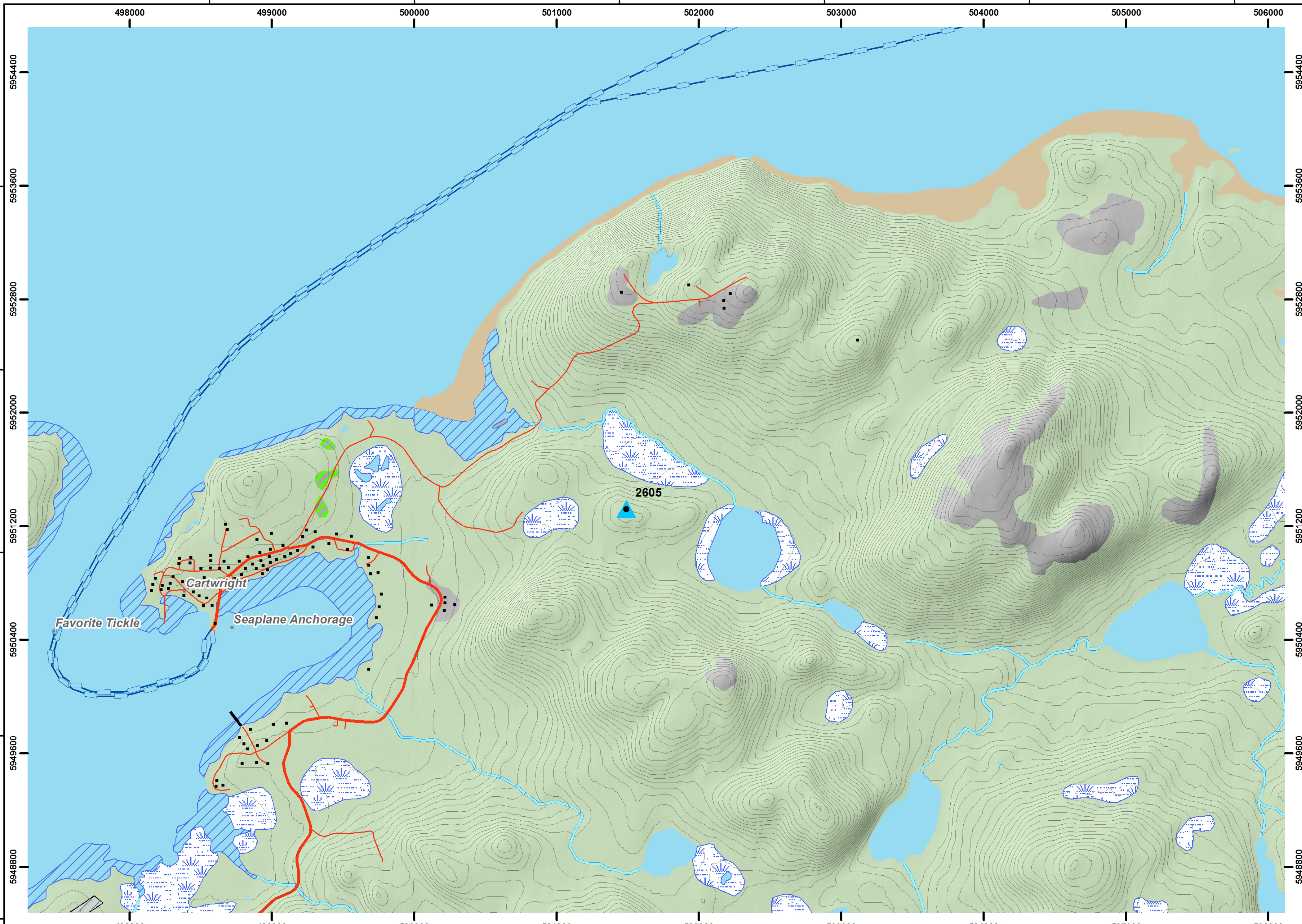
The location of the mast is shown on the map provided on next page.

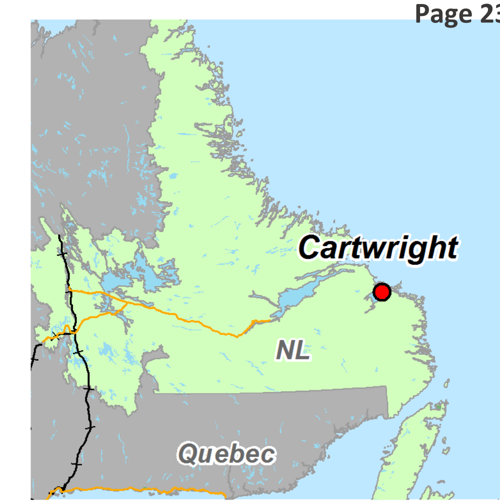
Table 2-1: Met Mast Characteristics (Coordinate System: NAD83)

ID	Type	Diameter (m)	Height (m)	Latitude	Longitude	Elevation (m)
2605	Square Lattice	0.404	36	N 53° 42' 38.1"	W 56° 58' 38.7"	57

The Cartwright met mast (#2605) is located east of the community on a gently rocky hill of approximately 50m elevation. The site consists in smooth bed rock with a thin layer of moss.

Pictures have been provided in Appendix A with views in the four main geographical directions at the met mast.





Legend

- Met Mast
- Building
- Contour (5m)
- Wharf
- Watercourse
- Ferry connection segment
- Mining area
- Reef
- Airport
- Wetland
- Waterbody
- Sand
- Vegetation

N

0 0.25 0.5 1 km

1:30,000

Spatial referencing UTM Zone 21 NAD83.

SOURCE :
Canvec - Natural Resource Canada 1:50 000
Action Canada Conference - Mt.Sophie viewer

NO	DESCRIPTION	BY	CHK'D	APP'D	DATE

REVISIONS

HATCH

DESIGNED BY SLADJANA PAVLOVIC
DATE: March 10, 2015

DRAWN BY SLADJANA PAVLOVIC
DATE: March 10, 2015

CHECKED BY Dany Awad
DATE: March 10, 2015

NALCOR

Cartwright - Overview Map

DISCLAIMER
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2.2 Measurement Campaigns

The mast characteristics, instrumentation, installation dates and periods of data collection are provided in this section.

2.2.1 Installation and Collection Date

The following table provides the date of mast installation and the period of data collection used in the analysis.

Table 2-2: Installation Date and Period of Relevant Data Collection

ID	Installation date	Date and time of first data used	Date and time of last data used
2605	November 5, 2013	December 1, 2013, 00:00 AM	November 30, 2014, 11:50 PM

2.2.2 Instrumentation

2.2.2.1 Sensors Mounting

The met mast was equipped with anemometers and wind vanes mounted on booms at several heights. The dimensions of the booms, their heights and orientations on the mast, were designed to comply with the best practices in wind resource assessment as specified in [1] and [2].

For the met mast, the instrument and installation parameters are provided in the table below. All instruments and met mast underwent regular maintenance checks.

Heated anemometers and wind vanes were installed to increase the data recovery rate during icing periods. An Autonomous Power System (A.P.S.) developed by Hatch was installed to power supply the heating instruments. The A.P.S. consists of a set of batteries charged by a small wind turbine through a controller.

Table 2-3: Installation Parameters of Instruments at the Met Mast

Channel	ID	Height (m)	Type	Date Installed	Date Uninstalled	Calibrated / Heated	Primary / Redundant
Mast 2605							
Data Acquisition System							
N/A	N/A	N/A	NRG Symphonie PLUS3	Nov 5, 2013	July 15, 2015	N/A	N/A
Anemometers							
#1	**A1**	**35.0**	**NRG #40C**	**Nov 5, 2013**	**July 15, 2015**	**Yes / No**	**P**
#2	A2	35.0	NRG Icefree III	Nov 5, 2013	July 15, 2015	Yes / Yes	R
#3	A3	26.0	NRG #40C	Nov 5, 2013	July 15, 2015	Yes / No	P

Channel	ID	Height (m)	Type	Date Installed	Date Uninstalled	Calibrated / Heated	Primary / Redundant
#4	A5	26.0	RMYoung 5103-AP	Nov 5, 2013	July 15, 2015	Yes / No	R
#13	A4	17.0	NRG #40C	Nov 5, 2013	July 15, 2015	Yes / No	P
Wind Vanes							
#7	**V1**	**33.0**	**NRG Icefree III**	**Nov 5, 2013**	**July 15, 2015**	**No / Yes**	**P**
#8	V2	26.0	RMYoung 5103-AP	Nov 5, 2013	July 15, 2015	No / No	R
#9	V3	15.0	NRG #200P	Nov 5, 2013	July 15, 2015	No / No	R
Temperature Sensor							
#10	T	34.0	NRG #110S	Nov 5, 2013	July 15, 2015	No / No	P

Note: Lines in bold font correspond to the anemometer and wind vane considered as the principal instruments for wind characterisation at the mast location.

2.2.2.2 Data Acquisition System

For met mast 2605, the instruments were connected to a data acquisition system which stored the data on a memory card. The data were then sent to Hatch computer network by a satellite communication system every 3 days.

3. Meteorological Data Analysis

This section presents a comprehensive analysis of the data collected. In the first section, the quality of the data is reviewed. The characteristics of the wind measured at the mast are then presented in Section 3.2 through a number of relevant parameters:

- monthly and annual average wind speeds;
- wind speed distribution;
- wind direction distribution;
- wind shear;
- turbulence intensity;
- 50-year recurrence wind speed.

In the final section, other climatic information such as measured temperature, calculated air density, wind power density and icing events is presented and discussed.

3.1 Quality Control

The quality and completeness of the data are key factors that determine the reliability of the wind resource assessment.

Data are collected periodically from the met masts and the quality of the data is analysed. This is done by applying a variety of logical and statistical tests, observing the concurrent readings from different instruments and relating these observations to the physical conditions at the site (e.g. wind shading, freezing potential, etc.). The process is semi-automated: the tests are implemented in a computer program developed by Hatch, but the expertise of quality analysts are required to accept, reject or replace data. There are many possible causes of erroneous data: faulty or damaged sensors, loose wire connections, broken wires, data logger malfunction, damaged mounting hardware, sensor calibration drift, icing events and different causes of shading (e.g. shading from the mast or from any obstacles at the site). A list of the possible error categories used during quality control is presented in Table 3-1. Data points that are deemed erroneous or unreliable are replaced by redundant data when available, or removed from the dataset.

The data recovery rate for the analysis period is then calculated for each of the instruments using the following equation:

$$\text{Data recovery rate}\,(\%) = \frac{\text{Number of valid observations}}{\text{Number of potential observations}} * 100$$

The “Number of valid observations” is evaluated once erroneous or unreliable data are replaced with available redundant data. The “Number of potential observations” is the theoretical maximum number of measurements that could be recorded during the analysis period. A high data recovery rate ensures that the set of data available is representative of the wind resource over the measurement period.

Table 3-1: Quality Control Table

Error Categories
Unknown event
Icing or wet snow event
Static voltage discharge
Wind shading from tower
Wind shading from building
Wind vane deadband
Operator error
Equipment malfunction
Equipment service
Missing data (no value possible)

3.1.1 Data Replacement Policy

Erroneous or unreliable data were replaced with available redundant data from instruments on the same met mast since these are considered to be equivalent wind measurements. Replacements were done directly or by using a linear regression equation. Direct replacement is applied to anemometers when the replaced and replacing instruments are of the same model, calibrated, at the same height, and well correlated. Direct replacement is also applied to wind vanes as long as they are well correlated.

An acceptable percentage of the dataset (7%) is replaced by equivalent instruments and it is considered to have a small impact on the uncertainty of the measurements.

3.1.2 Recovery Rates

The following table presents the recovery rates calculated for each instrument after quality control and after replacements have been completed according to the replacement policy.

Table 3-2: Instruments Data Recovery Rates

Mast ID	A1	A3	A4	V1	T
2605	99.3%	98.9%	95.3%	95.4%	100.0%

Note that the recovery rates for the following instruments are identical, given the replacement policy:

- A1 and A2; A3 and A5
- V1, V2 and V3

3.1.3 Data History

The data recovery rates exceed industry standards [5]. A number of data were affected on short periods of time by usual effects, such as shading effect and short period of icing events and were removed.

3.2 Wind Characteristics

3.2.1 Annual and Monthly Wind Speed

The monthly wind speeds measured at each anemometer are shown in the following figures for mast 2605. The data are presented in two formats (see Figure 3-1 and Figure 3-2):

a) for all instruments, the averaged monthly wind speed measured;
b) for A1, all monthly wind speeds are also reported.

Although the results for anemometers A2 and A5 are presented, they will not be considered in further calculations as these sensors were used primarily for quality control and replacement purposes.

As expected, the data confirm that wind speeds increase with height above ground level (see section 3.2.4 for a description of wind shear). Furthermore, the graphs show the seasonal pattern of wind, which decreases towards summer months and increases towards winter months.

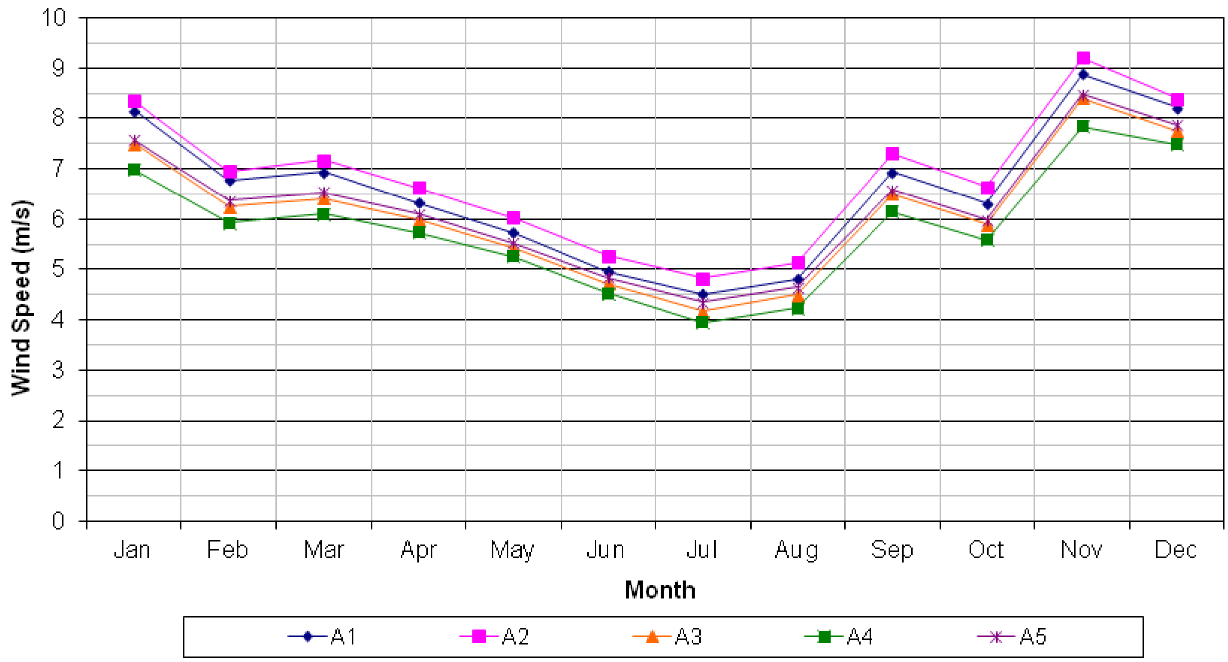


Figure 3-1: Averaged Monthly Wind Speeds for Each Anemometer at Mast 2605, December 1, 2013 to November 30, 2014

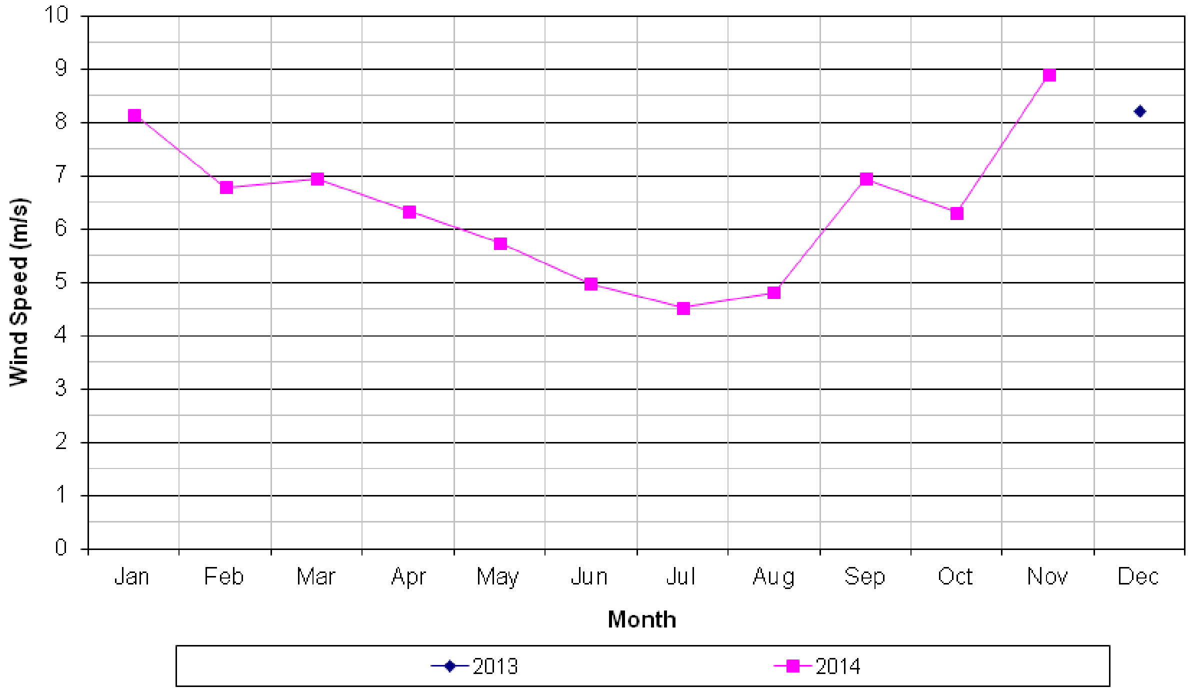


Figure 3-2: Monthly Wind Speeds Measured at the Top Anemometer at Mast 2605, December 1, 2013 to November 30, 2014

The following table provides, the average wind speed and the maximum 1-second gust observed, and specifies the averaging method used and the period of data considered. The averaging method varies as it depends upon the available dataset:

- Annual: average of the wind speed recorded over one or more full years.
- Annualised: the annualised wind speed is a weighted wind speed that is calculated from all available monthly average wind speeds–e.g. if 2 values are available for January and only one is available for February, the February value will have twice the weight of each January value in the final average.
- Average: due to insufficient data collection, the annual average wind speed was not calculated. The value given is the average of all available data.

Table 3-3: Wind Speed Characteristics at the Mast

Mast	Top Anemometer Height (m)	Period	Average Wind Speed (m/s)	Maximum 1-second gust (m/s)	Method
2605	35.0	December 1, 2013 to November 30, 2014	6.5	35.0	Annual

3.2.2 *Wind Speed Frequency Distribution*

The frequency distribution of wind speeds helps to evaluate how much power is contained in the wind (power is proportional to the cube of the wind speed). Wind turbines will produce more power as the wind speed increases (until reaching the "rated" value). Thus, as the frequency of higher wind speeds increases, more power can be produced.

Annual frequency distributions generally exhibit a Weibull shape that is controlled by its "scale factor" (closely linked to the average wind speed) and its shape factor.

The wind speed frequency distribution graph is presented below for the mast[1].

2605, anemometer A1, December 1, 2013 to November 30, 2014

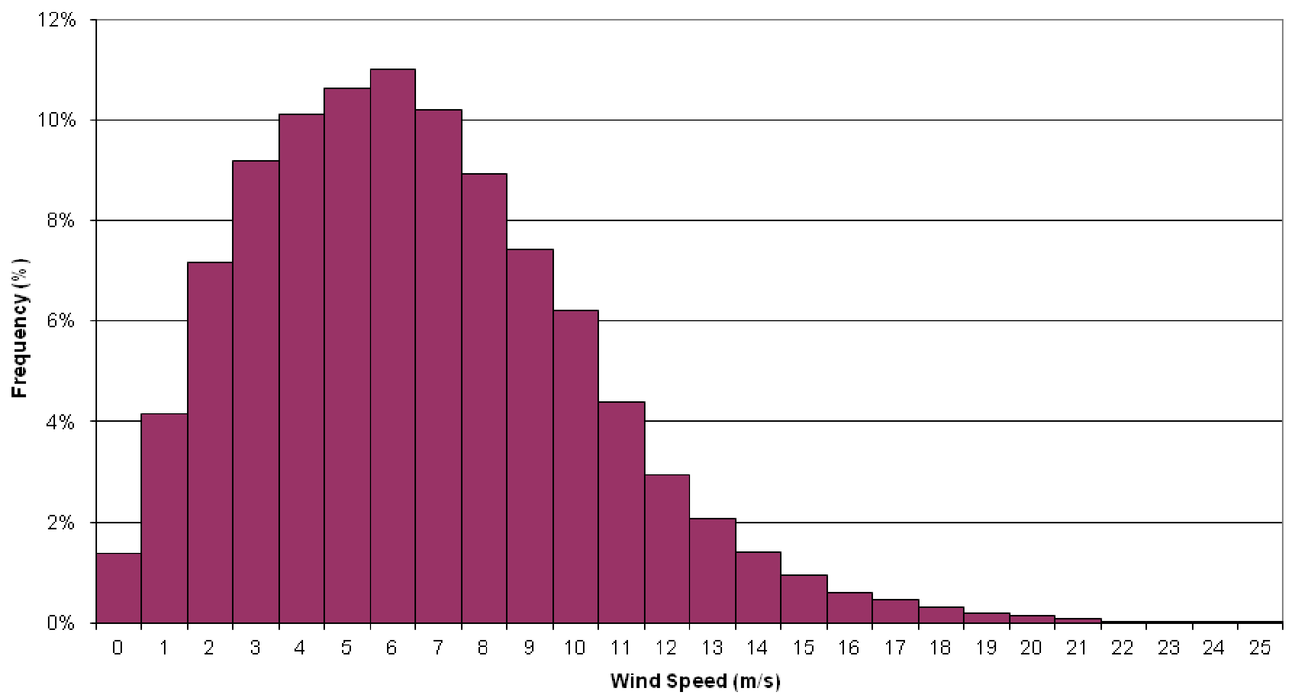


Figure 3-3: Wind Speed Frequency Distribution Graph

3.2.3 *Wind Rose*

The wind rose graph is presented below. The wind rose is divided into the conventional 16 compass sectors (22.5º wide sectors). Note that all compass orientations referenced in this report are based on the true geographic north, rather than the magnetic north.

[1] The 0 m/s wind speed bin indicates the fraction of the total number of measurements with a wind speed between 0 to 0.5 m/s. The other bins are 1 m/s wide and centered on the integer value (e.g.: the 1 m/s wind speed bin indicates the fraction with a wind speed between 0.5 to 1.5 m/s).

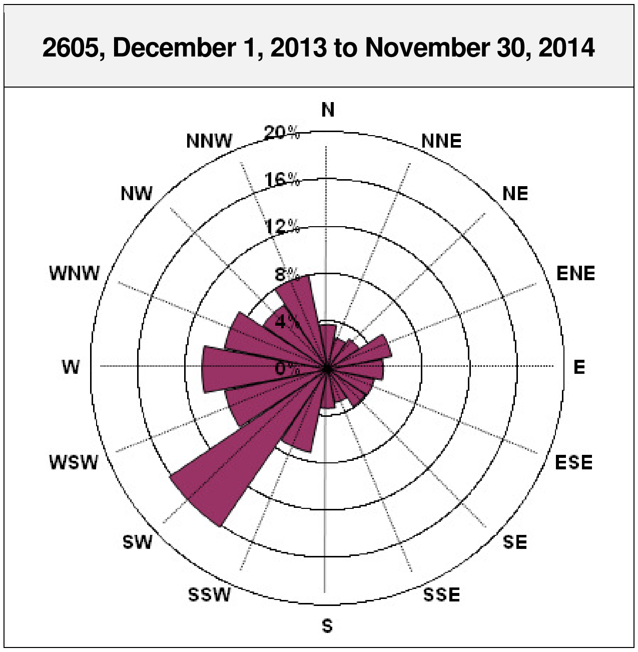


Figure 3-4: Wind Rose Graph

The wind rose indicates that a significant proportion of the wind blows southwest, across the project area.

Note that wind roses are not adjusted to the long-term. Moreover, differences in wind directions between the levels of measurement are small enough to be neglected. As a consequence, the present wind rose will be considered as representative of the long-term wind rose at hub height.

3.2.4 *Wind Shear*

Wind speeds typically increase with height above the ground, because the frictional drag decreases with altitude. The increase in wind speed with height is referred to as wind shear and is commonly modeled either by a logarithmic law or by a power law.

When the power law is used, the wind shear can be quantified by a wind shear exponent. "Rough" surfaces, such as forested lands and urban areas, have a more pronounced frictional drag than "smooth" surfaces, such as a snow covered field or grasslands–the former will be associated with higher wind shear exponents. Over a smooth, level, grass-covered terrain, the wind shear exponent is typically around 0.14; over snow or calm sea it may be as low as 0.10; and over urban areas or tall buildings it may be as high as 0.40.

The roughness is not the only surface property that has a direct effect on the wind shear. When there is dense vegetation, the vertical wind speed profile is displaced vertically above the canopy, thereby displacing the level of zero wind speed to a certain fraction of the vegetation height above the ground. The "displacement height" is defined as the height at which the zero wind speed level is displaced above the ground. The displacement height is taken into account in all wind shear estimations.

Finally, large topographic variations over short distances may also impact the wind vertical profile and thus affect the wind shear.

Hatch recommends using the log law to estimate the wind shear at mast locations. Internal studies have shown that the accuracy of the wind shear estimate is slightly improved with the log law when compared to the power law. When available, three wind speed measurements, each at a different height, are used and a log law curve is fitted through the average wind speeds at these heights. With the log law, the parameter that reflects roughness is called the roughness length, instead of the wind shear exponent. However, an equivalent wind shear exponent is calculated between the top anemometer height on a mast and the hub height for easier interpretation.

The equivalent wind shear exponent presented in this report was calculated between the top anemometer height of the mast and hub heights of 37 m and 40 m. The calculation was based on the measured wind speed at the anemometer height and the wind speed extrapolated to hub height by the log law method. The log law parameters were determined by fitting a logarithmic curve through the average measured wind speeds at the three measurement heights.

The average equivalent wind shear exponent is reported in the following table.

Based on our knowledge about the vegetation in the area of the mast, this value conforms to expected results.

Table 3-4: Average Wind Shear at the Mast

Mast	Period	Wind Shear
2605	December 01, 2013 to November 30, 2014	0.11

3.2.5 *Turbulence Intensity*

Turbulence characterises the gustiness of wind or high frequency changes in wind speed and direction (high turbulence is typical of very irregular wind flows, contaminated by whirls or vortices). Turbulence increases in areas with very uneven terrain and behind obstacles, such as buildings. In wind farms, it interferes with the effective operation of the wind turbines and increases their wear and tear.

The measurement of turbulence is expressed in terms of turbulence intensity, which is the standard deviation of the wind speed divided by the mean wind speed, over a given period. Turbulence intensity is expressed as a percentage. In the present study, the standard deviation and mean speed values are calculated from 1 second wind speed data averaged over a 10 minute period.

Turbulence intensity is more erratic and more difficult to quantify at low wind speeds. As a consequence, only wind speeds in excess of 4 m/s are used to calculate of the turbulence intensity. This threshold is consistent with IEC standards for wind turbine power performance measurements [4].

The turbulence intensity value was calculated with the top anemometer data.

The average turbulence intensity is reported in the next table. This value is considered moderate according to the reference values defined in reference [2][2]. It is expected that turbulence will decrease with height, as the effect of obstacles and surface roughness will diminish.

Table 3-5: Average Turbulence Intensity at the Mast

Mast	Anemometer used	Period	Turbulence Intensity (%)
2605	A1	December 01, 2013 to November 30, 2014	14.4

3.2.6 50-year recurrence wind speed

The selected wind turbines Northern power 100 (NPS100) and Emergya Wind Technologies 900 kW (EWT900) are designed to survive a certain level of loading caused by an extreme wind event. Based on the specification provided by the manufacturers, the extreme survival wind speed at hub height is 59.5 m/s (see Appendix B).

At least 7 years of data at the met mast location or a nearby reference station are required. The Gumbel distribution was used to predict the once-in-fifty-year extreme wind speed. The data were extrapolated to hub heights of 37 m (NPS100) and 40 m (EWT900) with a power law exponent of 0.11 suggested for gusts as per Wind Energy Handbook [2] and IEC 61400-1 standard.

In the case of Cartwright project, the met mast has only 18 months of data. Thus, data from Cartwright Environment Canada station were used and based on hourly data at 10 metres height. The data cover the period from 2007 to 2014. The 50-year recurrence maximum wind speeds were estimated to be 49.4 m/s at 37 m and 49.8 m/s at 40 m which respect the turbines' specifications.

3.3 Other Climatic Data

3.3.1 Temperature

Temperature was measured at a height of 34 m. The following table presents the average monthly and annual temperature measured. The coldest 10-minute temperature recording measured during the data collection period was -30.0℃ in the morning of January 8, 2015.

[2] Low levels of turbulence intensity are defined as values less than or equal to 0.10, moderate levels are between 0.10 and 0.25, and high levels are greater than 0.25. This classification is for meteorological turbulence only; it should not be used in comparison with IEC models. Meteorological turbulence should not be used to establish the wind turbine class.

Table 3-6: Average Monthly and Annual Temperatures

Mast ID	Monthly Air Temperature (°C)												Annual
	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	
2605	-13.6	-14.6	-12.0	-2.6	1.7	10.0	15.1	13.9	8.4	5.5	-4.3	-15.0	-0.6

3.3.2 Air Density

Wind energy is directly proportional to the air density. Consequently, the amount of energy produced by a wind turbine will also be directly proportional to the air density at the turbine location. Air density decreases with increasing temperature, decreasing pressure and increasing altitude.

Based on the measured temperatures and the standard barometric pressure of 101.3 kPa at sea level, the monthly average air densities were calculated. Note that to correct for changes in atmospheric pressure with height, the calculations account for the site elevation. The values were calculated over the entire analysis period reported in Table 2-2.

Table 3-7: Monthly and Annual Average Air Density

Mast ID	Monthly Air Density (kg/m^3)												Annual
	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	
2605	1.34	1.35	1.34	1.29	1.27	1.23	1.21	1.22	1.24	1.25	1.30	1.35	1.30

3.3.3 Power density

Wind speed, wind direction and air density data can be combined to provide information about the average power density at mast location. Wind power density indicates how much energy is available at a given instant for conversion by a wind turbine[3]. For example, strong winds in the winter, when the air is colder and denser, will have a higher power density (i.e. carry more energy) than the same strong winds in the summer. Though power is an instantaneous value, it is calculated as an average over a given period of time.

Tables of the power density distribution per direction and per month were produced at the top anemometer height and are presented below.

At mast 2605, the most powerful winds come from southwest to west-northwest, and appear in winter months. The annual average power density is 467 W/m^2 at 35 m.

[3] Note that the units "W/m^2" refer to m^2 of rotor swept area.

Table 3-8: Table of Wind Power Density per Direction, December 1, 2013 to November 30, 2014

Wind Power Density per Direction (W/m^2)															
N	**NNE**	**NE**	**ENE**	**E**	**ESE**	**SE**	**SSE**	**S**	**SSW**	**SW**	**WSW**	**W**	**WNW**	**NW**	**NNW**
434	565	365	298	233	297	438	194	153	241	558	487	620	677	603	517

Table 3-9: Table of Wind Power Density per Month, December 1, 2013 to November 30, 2014

Wind Power Density per Month (W/m^2)												Annual Average
Jan	**Feb**	**Mar**	**Apr**	**May**	**Jun**	**Jul**	**Aug**	**Sep**	**Oct**	**Nov**	**Dec**	
677	426	436	307	206	151	111	129	342	280	825	579	467

3.3.4 Icing Events

Icing affects the operation of wind turbines. Icing on any exposed part of the turbine can occur in the form of wet snow (generally associated with temperatures between 0°C to 1°C), super-cooled rain or drizzle (that can occur at temperatures between 0°C to -8°C, but mostly in the upper part of this range), or in-cloud icing (that can occur below - 2°C). Losses during production due to ice occur in several ways:

- Ice accumulation on the blades alters their aerodynamic profile, reducing the power output.

- Nacelle-mounted instruments accumulate ice and give inaccurate readings. The turbine control system may detect a fault condition due to the turbine output being much greater than expected. This expectation is based on the wind speed. As a result, the turbine will be shut down until the ice is removed from the instruments and the turbine is reset.

- Asymmetric icing causes mass or aerodynamic imbalance leading to vibrations. Control systems that sense vibrations will normally shut down when these vibrations occur.

Icing is a complex phenomenon and predicting icing from meteorological conditions is notoriously difficult, requires a good set of observations from a number of meteorology variables, and can be misleading. As no reliable instrument is presently available to detect and quantify icing events for the purpose of estimating their impact on wind energy production, Hatch uses several tests during data quality control to detect icing events: detection of unusual standard deviations or changes with time of wind speeds and directions, comparison of measurements from a heated anemometer and a standard anemometer at the same level, in parallel with the measurement of temperature.

These tests cannot distinguish between the different types of icing, but a rough approximation can be done by utilising the temperature ranges measured during icing events. Therefore, in the following estimate, we will consider two categories: “glaze”, which is assumed to include wet snow, super-cooled rain and drizzle, and “rime ice”, which is assumed to include in-cloud icing and the very low temperature part of super-cooled rain or drizzle. The threshold of -5°C is used to differentiate between rime ice (below -5°C) and glaze (above -5°C).

The following table presents the estimated number of icing events in a month and the type of event assumed to occur in the project area. This estimate is based on the average of icing events detected on the mast during the measurement campaign.

Table 3-10: Estimated Hours of Icing Events, November 5, 2013 to April 30, 2015

	January	February	March	April	May	June	
Hours	23	24	31	31	48	2	
Rime	30%	100%	40%	0%	0%	0%	
Glaze	70%	0%	60%	100%	100%	100%	
	July	**August**	**September**	**October**	**November**	**December**	**Annual**
Hours	0	0	0	0	79	38	275
Rime	-	-	-	-	0%	10%	18%
Glaze	-	-	-	-	100%	90%	82%

4. Long-term Wind Speed at Hub Height

The previous section presented the analysis of the wind regime as it was measured by the met mast installed on the project site. However, to forecast the energy production of a wind power plant, wind data that represent the historical wind conditions at the site are required. Unfortunately, wind resource assessments are generally conducted for a limited number of years, often no more than one or two years, which is not sufficient to capture the year-to-year variability of wind. For example, in North America, the annual average wind speed exhibits a standard deviation of about 6% (or 1σ from a normal distribution) of the long-term average wind speed. Hence, the maximum deviation from the average wind speeds could reach as much as 20% (or 3.3σ). Consequently, it is necessary to translate the measured short-term data into long-term data. This is done through a correlation/adjustment process that makes reference to a meteorological station where historical data are available.

Moreover, when the top anemometers of the met masts are mounted at a lower height than the expected hub height of the wind turbines, the long-term data must also be extrapolated from these anemometer heights to the wind turbine's hub height.

The long-term projection process is presented in the next section and is followed by the extrapolation to hub height.

4.1 Long-term Projection

When required, selecting a reference dataset to perform a long-term correlation and adjustment is determined by the following process:

- A quality assessment of the potential long-term reference stations for the site (history, similarity of the local climate with regards to the meteorology mast climate, etc.);

- A quality assessment of the correlation equations obtained with acceptable long-term reference stations and the measured data for the concurrent period;

- A comparison of the long-term correlation results obtained with all acceptable reference stations;

- A crosscheck of the resulting long-term adjustments with the measured data and the long-term trends at nearby reference stations or at a regional level;

Once the reference dataset is selected, it is used to adjust the met mast data to long-term conditions. This can be achieved either by synthesizing non existing years of data at the met mast site or by applying an adjustment factor to the measured data in order to better reflect the reference period. The process is as follows:

- The measured data from the met mast is correlated with the reference dataset;

- If the correlation parameters meet the synthesis criteria, then data are synthesized at the measurement mast for the complete reference data period; this method is referred to as the Measure-Correlate-Predict (MCP);

- If the criteria are not met but a good correlation can still be obtained with hourly or daily intervals, then the measured dataset is scaled up (or down) to long-term using the reference long-term average wind speed and the correlation equation obtained; this method is referred to as the Long-term Adjustment;

- If no correlation can be clearly established between a reference site and the met mast site, the measured data stay unchanged.

4.1.1 *Selection of reference dataset*

The present section summarises the results of the analysis.

Among the possible set of reference stations, one station was selected and considered suitable for the long-term projection of the data at the met mast. This station is Cartwright monitored by Environment Canada (EC). The location of this station is given in the table below.

Table 4-1: Identification of the Long-term Reference

Name	ID	Instruments Height (m)	Latitude	Longitude	Elevation (m)
Cartwright	8501100	10.0	N 53° 42' 30.0"	W 57° 02' 06.0"	14.3

4.1.2 *Long-term Adjustment*

The long-term adjustment consists of:

- Correlating short term data at the met mast with short term data at the reference station;

- Using the obtained linear regression equation, Y = m X + b, where X represents the long-term average wind speed at the reference station and Y is the estimated long-term average at the met mast;

- Applying an adjustment factor (to speed up or scale down) to the met mast short term data in order to obtain an average wind speed equal to the estimated long-term average at met mast (i.e. Y).

For masts 2605, which displayed 18 months of data recorded, the long-term adjustment method was used for the long-term projection.

The wind speed data of the met mast were correlated to the concurrent wind speed data at the long-term reference station Cartwright. The hourly correlation with the reference data was acceptable (R^2 greater than or equal to 0.7 is good correlation, above 0.85 is excellent), i.e. the hourly values of the reference station are representative of the hourly wind data of the project site. The results of the correlation are given in the following table. Linear regression equations were used to compare the data, where *m* is the slope of the equation, *b* is the intercept, and R^2 is the coefficient of determination.

Table 4-2: Correlation between Reference Station and met mast Wind Speeds

Reference Station	Met Mast	Correlation Period		Hourly Wind Speed Correlations		
		Beginning	End	m	b	R^2
Cartwright	**2605**	December 1, 2013	November 30, 2014	0.969	2.1	0.69

The regression equations were then used to estimate the long-term average wind speed at the mast as a function of the long-term wind speed at the reference station. The estimated long-term average at the Cartwright station is 5.0 m/s. It was estimated by averaging all annual averages over the period 2007 to 2014 (except 2012 having a very low recovery rate). The results are presented in the following table.

Table 4-3: Long-term Adjustment factor at the met mast

Met Mast	Wind Speed over Correlation Period (m/s)	Long-term Annual Wind Speed (m/s)	Adjustment Factor (%)
2605	6.5	7.0	6.4

The Cartwright EC station is a well maintained station as confirmed by an Environment Canada specialist. Since 2007, the U2A instrument has been replaced every year by new or rebuilt sensors and was changed to Ultrasonic sensor in November 2014. This modification should not affect the annual average wind speed of 2014 which is 4.5 m/s. The wind speed of 2014 is 0.5 m/s less compare to the long-term annual wind speeds measured at Cartwright station covering the period 2007 to 2014. It seems 2014 was a less windy year than previous years, which explain the high adjustment factor of 6.4% of the mast data.

Finally, the 10-minute measured data recorded at the met mast were scaled by the adjustment factor to reflect the long-term value. In terms of the wind direction data, the one-year dataset for the met mast remained untouched. As a result, the mast has a set of wind speeds and wind directions that are the best estimate of the long-term wind regime.

4.2 Extrapolation to Hub Height

The wind shear exponent, calculated with the measured data, was used to adjust the dataset to hub heights. The results are presented in the following table.

Table 4-4: Estimated Long-term Wind Speed at Hub Heights*

Met Mast	Estimated Long-term Wind Speed at Top Anemometer Height (m/s)	Estimated Long-term Wind Speed at Hub Height (m/s)	
		37 m	40 m
2605	7.0	7.3	7.3

* Estimated using the calculated wind shear

5. Wind Resource Mapping and Projected Energy Production

Met masts provide a local estimate of the wind resource. Met mast locations are chosen based on how representative they are of the project site and in particular for potential wind turbine locations. However, since the number of met masts is usually limited compared to the expected number of wind turbines, it is necessary to build a wind flow map based on these measurements to extend the wind resource assessment to the whole project area.

Wind modeling software, such as MS-Micro and WAsP, are known to produce erroneous wind flows over complex terrain. In this case, Hatch applies a method based on the Ruggedness Index (RIX) to calculate the wind flow for each mast data set while correcting errors on wind speed[4]. All produced wind flows are then merged by a distance-weighting process. When the RIX correction is not applicable, wind flows are calculated with each mast dataset and simply merged together by a distance-weighting process, without a RIX correction.

Once the wind flow map is built, it is possible to optimise the size and layout of the foreseen wind farm for the project, and then to calculate the projected energy production. When necessary, wind turbine hub heights as well as met mast heights are corrected with the estimated displacement height. This is computed to account for the influence of trees on the wind flow (see section 3.2.4). These corrections result in an effective hub height for each wind turbine.

The wind flow and energy production are calculated with specialised software that require, apart from the met masts long-term data, background maps that contain the information on topography, elevation, roughness lengths (related to the land cover) and potential obstacles. This is also used in conjunction with the wind turbine characteristics. Finally, wind farm losses must be estimated in order to complete the energy estimate.

The first part of this section introduces the information and the methodology used to calculate the wind flow.

The next part will present the optimisation process and the results in terms of energy production.

The software used to map the wind resource and to calculate the energy production include:

- WAsP Issue 11.01.0016 from Risø for wind resource mapping;
- Wind Farmer Issue 4.2.2 from Garrad Hassan for layout optimisation and energy production calculations.

5.1 Background Data

5.1.1 Topography and elevation

The topographic and elevation data come from files provided by the National Topographic Data Base (NTDB).

The contour line interval is 5 m within the project area and 20 m outside.

[4] Bowen, A.J. and N.G. Mortensen (2004). WAsP prediction errors due to site orography. Risø-R-995(EN). Risø National Laboratory, Roskilde. 65 pp.

5.1.2 Roughness

The base map for roughness lengths was determined from land cover information included in the NTDB files. This map was then checked and corrected using satellite imagery from Google Earth. Around mast locations and wind turbines, pictures and information noted during site visits were also used to check and modify the land cover information. The spatial resolution considered for the roughness lengths is 30m.

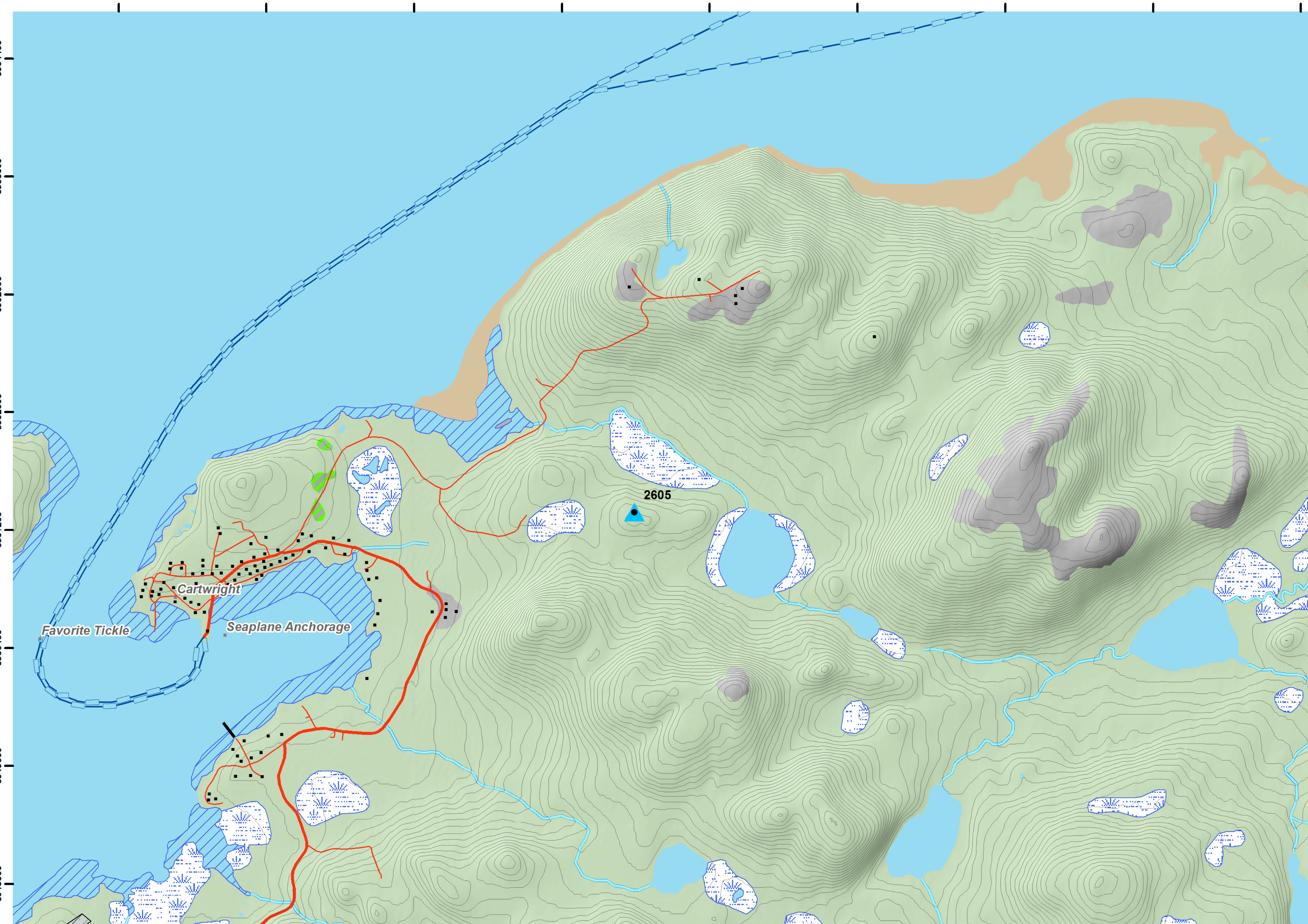
The following table details the roughness lengths used by land cover category.

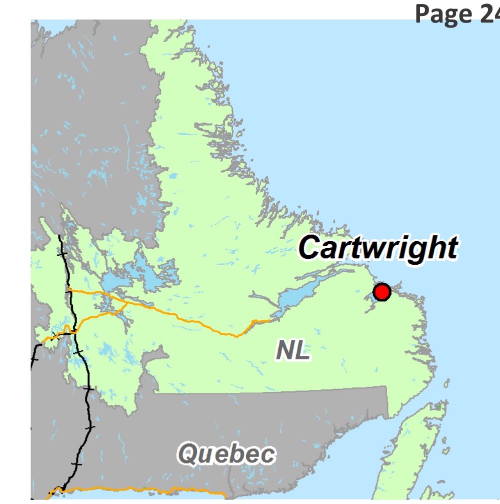
Table 5-1: Roughness Lengths Categories

Land Cover Type	Roughness Length (m)
Open farmland, high grass	0.04
Forest	0.8
Water	0
Building	0.5

5.1.3 Background Map

The background map, showing topography and contour lines is provided on the next page.





Legend

- Met Mast
- Building
- Contour (5m)
- Wharf
- Watercourse
- Ferry connection segment
- Mining area
- Reef
- Airport
- Wetland
- Waterbody
- Sand
- Vegetation

N

0 0.25 0.5 1 km

1:30,000

Spatial referencing UTM Zone 21 NAD83.

SOURCE :
Canvec - Natural Resource Canada 1:50 000
Action Canada Conference - Mt.Sophie viewer

NO	DESCRIPTION	BY	CHK'D	APP'D	DATE

REVISIONS

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DESIGNED BY SLADJANA PAVLOVIC
DATE: March 10, 2015

DRAWN BY SLADJANA PAVLOVIC
DATE: March 10, 2015

CHECKED BY Dany Awad
DATE: March 10, 2015

NALCOR

Cartwright - Overview Map

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5.2 Wind Flow Calculation

5.2.1 Terrain Complexity

The wind flow is produced over semi-complex terrain. Wind modeling software, such as MS-Micro (used in Windfarm) and WAsP, are known to produce erroneous wind flows over complex terrain. Depending on the topography, predicted wind speeds can be over or under-estimated at a given location. Errors can reach more than 20% in very complex areas.

In the present case, the complexity of the terrain is considered moderate and its effect on the modelled wind is not considered problematic.

5.2.2 Parameters

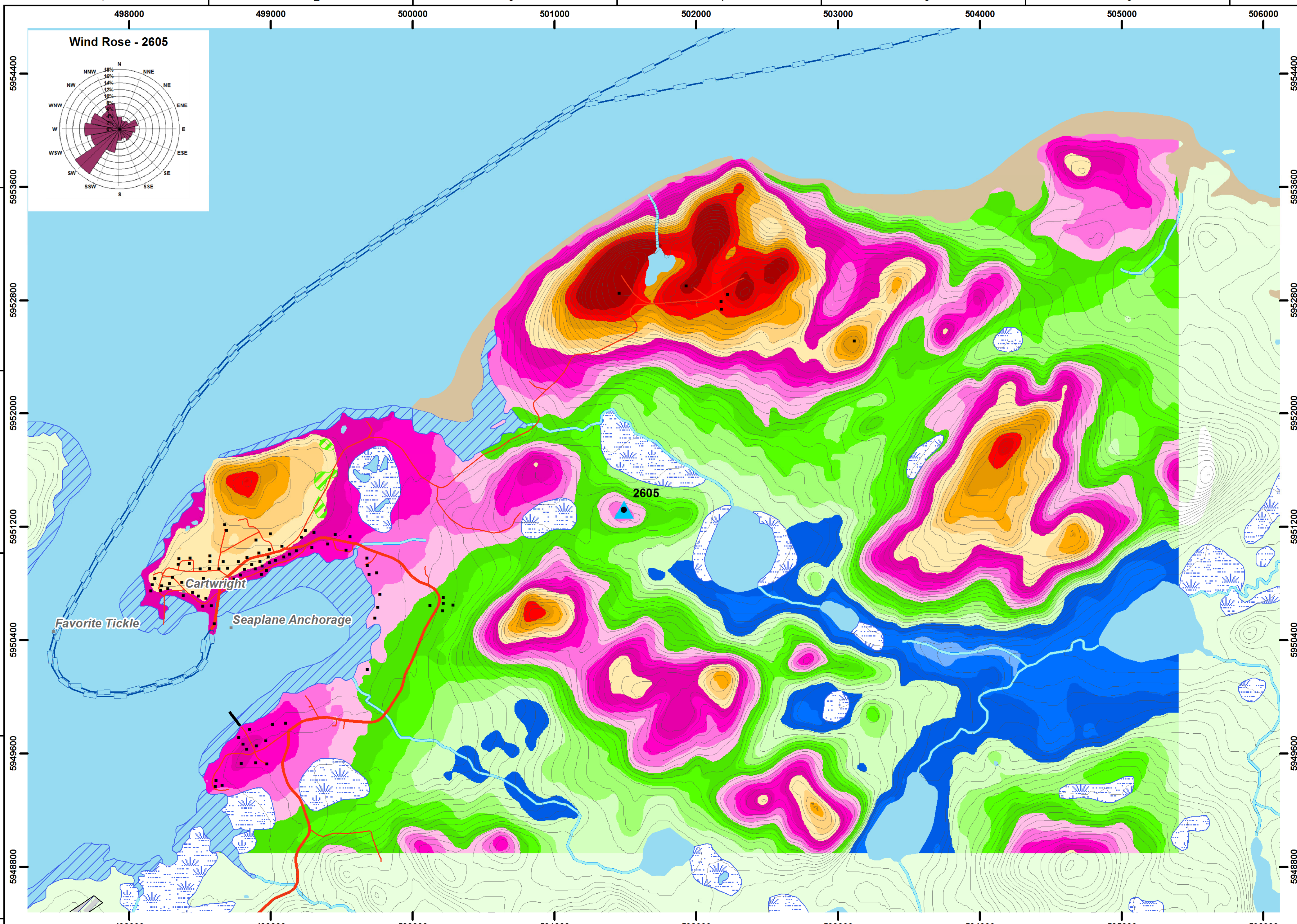
The following parameters were used to calculate the wind flow map.

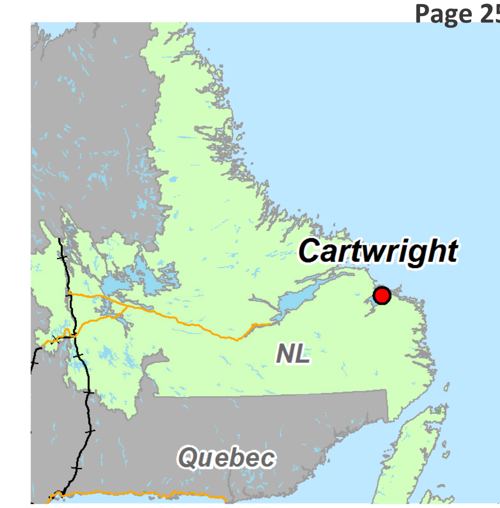
Table 5-2: Wind Flow Calculation Parameters

Parameter	Value
Wind Resource Grid Spatial Resolution	50 m
Calculation Area	7.5 km by 5.5 km
Reference Mast	2605
Reference Height	Top Anemometer Height
Calculation height	37 m
Vertical Extrapolation Method	Based on measured wind shear
Roughness Change Model	WAsP Standard Model

5.2.3 Results

The wind flow map used for layout optimisation and energy production estimates is presented on the next page.





Legend

- Met Mast
- Building
- Contour (5m)
- Wharf
- Watercourse
- Ferry connection segment
- Mining area
- Reef
- Airport
- Wetland
- Waterbody
- Sand
- Vegetation

WindFlow (37m) m/s

- < 5
- 5 - 5.25
- 5.25 - 5.5
- 5.5 - 5.75
- 5.75 - 6
- 6- 6.25
- 6.25 - 6.5
- 6.5 - 6.75
- 6.75 - 7
- 7 - 7.25
- 7.25 - 7.5
- 7.5 - 7.75
- 7.75 - 8
- 8 - 8.25
- 8.25 - 8.5
- 8.5 - 8.75
- 8.75 - 9
- 9 - 9.25
- 9.25 - 9.5
- 9.5 <

N

0 0.25 0.5 1 km

1:30,000

Spatial referencing UTM Zone 21 NAD83.

SOURCE :
Canvec - Natural Resource Canada 1:50 000
Action Canada Conference - Mt.Sophie viewer

NO	DESCRIPTION	BY	CHK'D	APP'D	DATE

REVISIONS

Wind resource map created by Hatch with WAsP 11.01.0016
Height of calculation: 37 m
Spatial resolution of wind resource grid: 50 m
Source file: Cartwright_2605_GridWRG_37m_WF2.grd
Source of data used to create the wind flow:
Topographic data are provided by the Center for Topographic Information (NRCan).
Meteorological data were collected from mast 2605, located 1 km on average from the center of the map, between 01/12/2013 and 30/11/2014. Data were controlled by Hatch.
Met data were adjusted for long term with reference to station Environment Canada Cartwright # 8501100 (reference period 2007-2014). It is believed that the present map gives a reliable overall picture of the wind resource. However, it is advised to confirm any information obtained from this map at any location by on-site measurements.

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DATE: March 10, 2015

DRAWN BY SLADJANA PAVLOVIC
DATE: March 10, 2015

CHECKED BY Dany Awad
DATE: March 10, 2015

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Cartwright - WindFlow 2

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5.3 Forecasting Energy Production

The layout was initially designed in order to maximise energy production. Turbines were spread out inside the project boundaries to minimise wake effects. The preliminary environmental screening and turbine extreme operating conditions also contributed to set the turbine locations.

5.3.1 Preliminary Turbine Selection

A preliminary turbine selection was performed using Windographer software by comparing the performance of different turbines at the location of the met mast, where the dataset was recorded. The main parameters used for the comparison were the capacity factor of the wind turbine for the site specific conditions as well as the turbine purchase cost. Only turbines that meet the following criteria were considered:

- Site’s turbine and turbulence class (IEC class II)
- Extreme wind and weather conditions (operation down to -40℃). The minimum 10-minute temperature recording of -30.0℃ during the monitoring campaign confirms the site conditions are within the operating range of the turbine.
- Turbine capacity ranges from 100 kW to 1,000 kW to meet the community load
- Wind turbine’s dimensions and weight versus crane capacity and accessibility

Hub heights of about 40 m to 50 m were used for this preliminary analysis.

Standard losses considered include: 12.5% technical losses and 2% wake losses.

The following table provides a summary of the turbine comparison.

Table 5-3: Windographer Results at the Mast Location

Turbine type	Turbine Class	Hub height (m)	Turbine Capacity (kW)	Mean Energy Output (MWh/yr)	Capacity Factor (%)	Turbine purchase cost ($)
Northern Power NPS100 Arctic	IIA	37	100	259	29.5	325,000
Aeronautica AW/Siva29-250	IIA/IIIA	37	250	571	26.1	656,000
Aeronautica AW/Siva47-500	IB/IIA	47	500	1,438	32.8	1,632,000
EWT DW52-250 (EWT250)	IIA	37	250	1,096	50.0	1,980,000
EWT DW52-500 (EWT500)	IIA	37	500	1,704	38.9	1,990,000
EWT DW52-900 (EWT900)	IIA	40	900	2,184	27.7	2,000,000

The capacity factors listed above in table 5-3 are taken from Windographer and may change as a function of the site’s optimized layout and should only be used for turbine comparison.

Due the lack of proven experience in remote arctic conditions, the Aeronautica wind turbine models were discarded from the analysis. Northern Power and EWT wind turbines have

been installed and are operating in similar site conditions in Nome, Alaska for EWT or in Kasigluk, Alaska for Northern Power and were thus further compared as part of the analysis.

The average community load at Cartwright during the project lifetime is around 500 kW. The following table shows the results of the WindFarmer optimization models using the required number of turbines to meet that load. The turbines were ranked based on their capacity factor, energy output and simple payback.

Table 5-4: Preliminary Turbine Selection Results

Turbine type	Number of wind turbine required	Total Capacity (kW)	Gross Energy Output (MWh/yr)	Gross Capacity Factor (%)	Total purchase cost (Million $)	Ranking
Northern Power NPS100 Arctic	**5**	**500**	**1,813**	**41.4**	**1.625**	**2**
EWT250	2	500	2,945	67.2	3.960	4
EWT500	1	500	2,447	55.8	1.990	3
EWT900	**1**	**900**	**3,379**	**42.8**	**2.000**	**1**

* Based on the gross energy output at 30 cents/kWh and the turbine purchase cost only.

Based on information provided by EWT, the 250 kW wind turbine has the same foundation design as the 500 kW and 900 kW machines and nearly the same price ($10,000 difference). Because of the similar turbine costs of the three EWT models, from a financial point of view, the EWT900 becomes the most suitable having the lowest simple payback, and would also benefit from potential lower constructability and BOP cost.

The Northern power NPS100 Arctic can also be considered as potential candidates for the Cartwright project since it is a proven turbine in arctic conditions, and would provide for more redundancy due to number of turbines. The NPS100 has the advantage of being a smaller turbine and would be less difficult from a logistic and crane accessibility stand point.

The NPS100 and EWT900 turbines are two models that meet the wind class of the site and have proven technology for cold and icy environments.

Even though a more detailed turbine selection exercise will be required in later phase of the project, the NPS100 and EWT900 are considered suitable candidate turbines in order to complete the preliminary energy estimates for the potential Cartwright project.

5.3.2 *Layout Optimization*

The following section shows the WindFarmer modeling results which further refines the energy estimates for the turbines selected at the potential turbine positions and to confirm the capacity factor values. The table below outlines the parameters and constraints assumed to influence optimisation.

Table 5-5: Layout Optimisation Parameters and Constraints

Parameter / Constraint	Value	
Annual Air Density	1.30 $kg.m^{-3}$ at 91 m.a.s.l.	
Turbulence Intensity	14.4% at mast 2605 ***Note****: average value for information, the turbulence intensity is actually entered by wind-speed bins and by direction for energy prediction calculation*	
Exclusion areas	Due to the lack of information in regard to setbacks for wind energy projects in Newfoundland and Labrador, general restriction rules were used: - 500 m from habitations - 100 m from public roads - 50 m from lakes and rivers - 2 km by 1 km buffer zone from the airport track	
WTG Minimum Separation Distance	Elliptical separation: Minimum of 6 rotor diameters on long axis Minimum of 3 rotor diameters on short axis Bearing of long axis: 255 degrees	
WTG Model	EWT900	NPS100 Arctic
WTG Rated Power (kW)	900	100
WTG Rotor Diameter (m)	51.5	20.7
WTG Hub Height (m)	40.0	37.0
WTG Power Curve	See Appendix B	
WTG Thrust Curve	See Appendix B	
Number of WTG's	1	5
Wind Farm Capacity (kW)	900	500
Wake Model	Modified Park Model used for optimisation and Eddy Viscosity Model for final energy calculation as recommended by Garrad Hassan	
Maximum Slope	10 degrees	
Optimization Strategy	Layout designed in order to maximise energy production.	

The project layouts are presented at the end of this section.

The layouts are still considered preliminary. Land restrictions, communication corridors, noise and visual impacts, and other site-specific matters need to be evaluated through a detailed environmental assessment. Available land, road and collection system costs are also issues that will need to be addressed before the site layout can be finalized.

5.3.3 Energy production

Once the optimised layout has been produced, the energy production for each wind turbine is calculated. When necessary, wind turbine hub heights as wells as met mast heights are corrected with the estimated displacement height. This is computed to account for the influence of trees on the wind flow. These corrections result in an effective hub height for each wind turbine.

The calculation was executed with the power curves and thrust curves used for the optimisation and presented in Appendix B. The additional losses are described in the next section.

Note that air density is corrected by the software for each turbine location according to its elevation.

The following table is a summary of the estimated energy production. Detailed energy figures are presented per wind turbine on the next page.

Table 5-6: Wind Farm Energy Production Summary

Item	Layout 1 - EWT900	Layout 2 - NPS100 Arctic
WTG Rated Power (kW)	900	100
WTG Rotor Diameter (m)	51.5	20.7
WTG Hub Height (m)	40.0	37.0
Number of Wind Turbines	1	5
Wind Farm Capacity (kW)	900	500
Mean Free Wind Speed across Wind Farm (m/s)	8.2	7.9
Average Wake Losses (%)	0.0	4.0
Energy Production Before Additional Losses* (MWh/yr)	3,379	1,813
Capacity Factor Before Additional Losses* (%)	42.8	41.4
Additional Losses (%)	14.2	14.0
Net Energy Production (P50) (MWh/yr)	**2,898**	**1,559**
Net Capacity Factor (%)	**36.7**	**35.6**

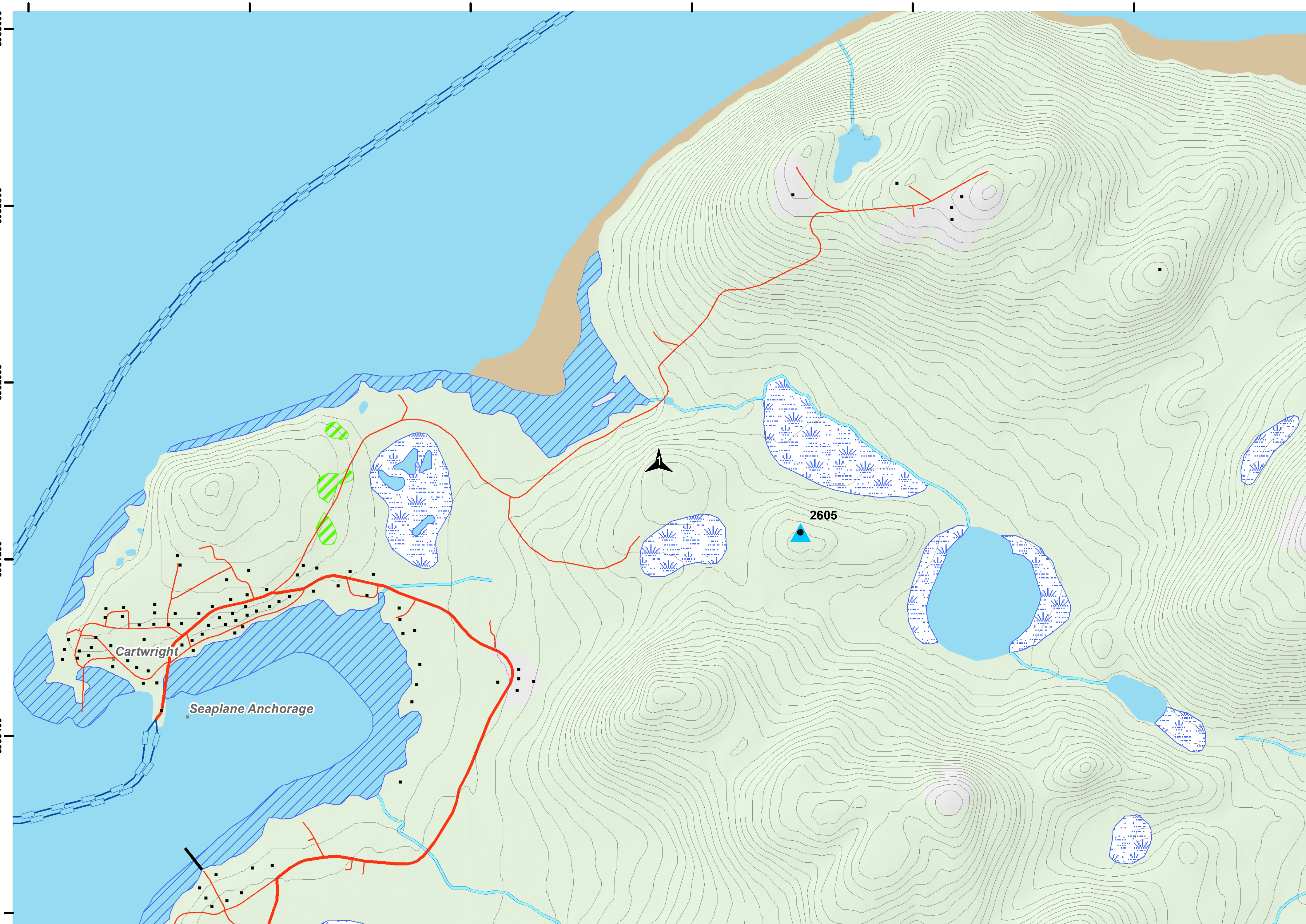
* Includes topographic effect and wake losses

Table 5-7: Forecasted Energy Production at Wind Turbines

Turbine ID	Easting (m)	Northing (m)	Altitude (m)	Mean Free Wind Speed (m/s)	Gross Energy Production* (MWh / Year)	Wake Losses (%)	Gross Energy - Wake* (MWh / Year)	Turbulence Intensity** (%)
Layout 1 - EWT900								
1	500851	5951650	47	8.2	3,379	0.0	3,379	15.1
Layout 2 - NPS100 Arctic								
1	500934	5951612	49	7.9	382	6.9	355	18.0
2	500888	5951482	48	7.7	367	2.9	356	17.1
3	500818	5951540	47	7.9	378	3.1	366	17.3
4	500783	5951622	41	7.8	376	1.8	369	17.0
5	500877	5951651	47	8.0	387	5.2	367	17.9

* Gross energy production includes topographic effect; "Gross energy – Wake" includes topographic effect and wake losses.

** Turbulence Intensity includes ambient turbulence and incident turbulence. The values represent true meteorological turbulence; they should not be compared directly with IEC models and consequently should not be used to establish the wind turbine class.



Legend

- Wind Turbine
- Met Mast
- Building
- Contour (5m)
- <all other values>
- Road
- Wharf
- Watercourse
- Ferry connection segment
- Mining area
- Reef
- Airport
- Wetland
- Waterbody
- Sand
- Vegetation

N

0 0.25 0.5 1 km

1:20,000

Spatial referencing UTM Zone 21 NAD83.

SOURCE :
Canvec - Natural Resource Canada 1:50 000
Action Canada Conference - Mt.Sophie viewer

NO.	DESCRIPTION	BY	CHK'D	APP'D	DATE

REVISIONS

Turbine model: EWT DW52-900
Number of turbines: 1
Site capacity: 900 KW
Turbine rated power: 900 KW
Hub height: 40 m
File reference: Cartwright_WF2_Lay3.txt

HATCH

DESIGNED BY
DANY AWAD
DATE: August 06, 2015

DRAWN BY
SLADJANA PAVLOVIC
DATE: August 06, 2015

CHECKED BY
DANY AWAD
DATE: August 06, 2015

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Cartwright - Layout 1

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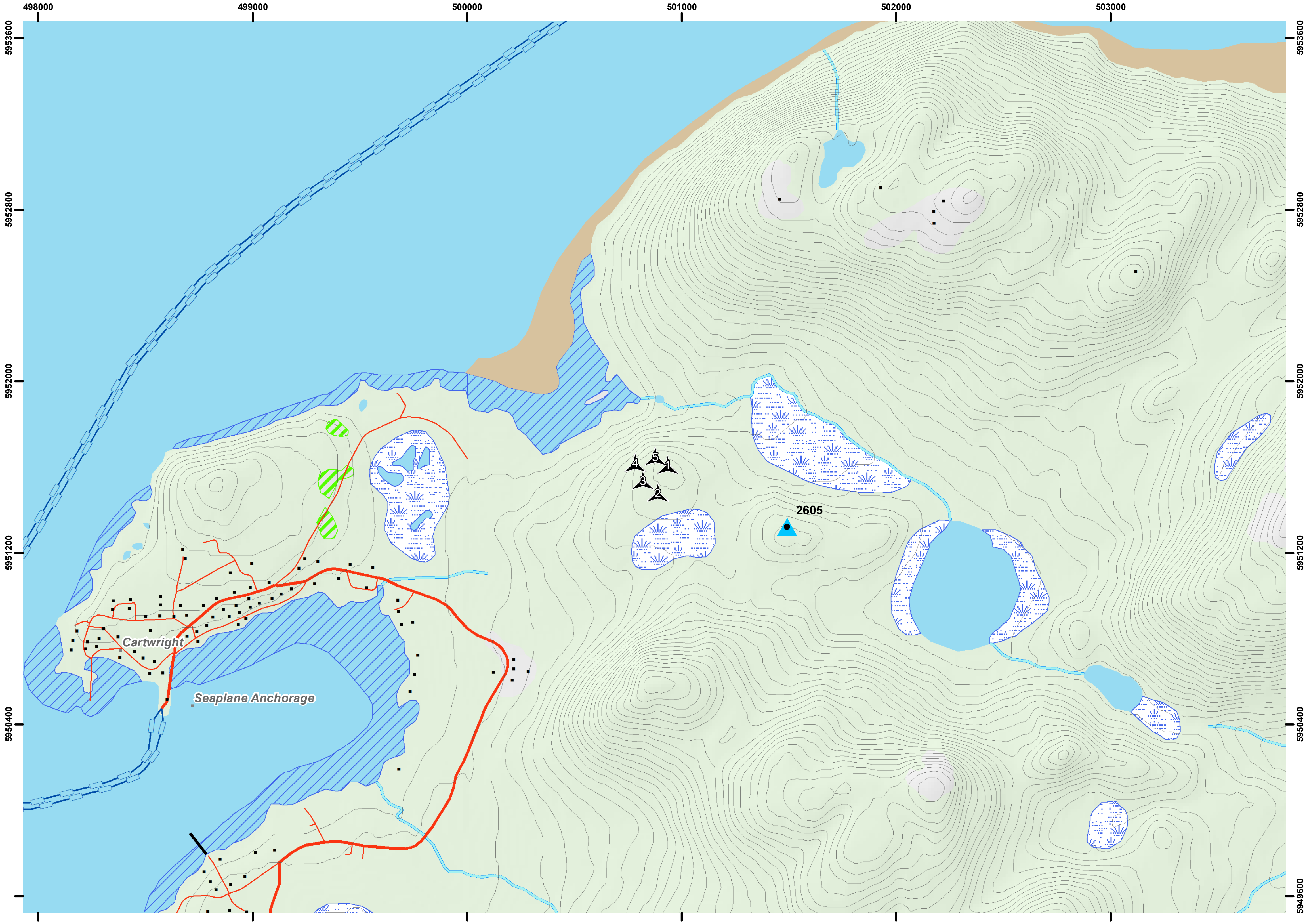

Legend

N

- Wind Turbine
- Met Mast
- Building
- Contour (5m)
- Road
- Wharf
- Watercourse
- Ferry connection segment
- Mining area
- Reef
- Airport
- Wetland
- Waterbody
- Sand
- Vegetation

0 0.25 0.5 1 km

1:20,000

Spatial referencing UTM Zone 21 NAD83.

SOURCE :
Canvec - Natural Resource Canada 1:50 000
Action Canada Conference - Mt.Sophie viewer

NO.	DESCRIPTION	BY	CHK'D	APP'D	DATE

REVISIONS

Turbine model: Northern Power 100
Number of turbines: 5
Site capacity: 500 KW
Turbine rated power: 100 KW
Hub height: 37 m
File reference: Cartwright_WF2_Lay5.txt

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DESIGNED BY DANY AWAD DATE: August 31, 2015	DRAWN BY SLADJANA PAVLOVIC DATE: August 31, 2015
CHECKED BY DANY AWAD DATE: August 31, 2015	

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Cartwright - Layout 2

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5.3.4 Losses

This section provides a description of the estimated losses included in the P50 estimate. These losses include environmental, electrical, availability, turbine performance losses and wake effects. The P50 is defined as the exceedance probability that denotes the level of annual wind-driven electricity generation that is forecasted to be exceeded 50% of the year. Half of the year's output is expected to surpass this level, and the other half is predicted to fall below it. Loss estimates should be reviewed as more detailed information becomes available.

The losses considered are presented in the following table and described hereafter.

Table 5-8: Wind Farm Losses

Loss Category	Loss Type	Losses (%) Layout 1 - EWT900		Losses (%) Layout 2 - NPS100 Arctic	
Environmental	Blade Soiling and Degradation	1.0	**4.5**	1.0	**4.2**
	High Wind Hysteresis	0.2		0.2	
	Icing	3.0		3.0	
	Lightning	0.0		0.0	
	Low Temperature Shutdown	0.4		0.0	
Electrical	Collection Network	1.3	**3.7**	1.3	**2.2**
	Auxiliary power	2.4		0.9	
Availability	Wind Turbine Availability	5.0	**5.8**	6.5	**7.3**
	Collection Network Outage	0.6		0.7	
	Grid Availability	0.2		0.2	
Turbine Performance	Out-of-range Operation	1.0	**1.0**	1.0	**1.0**
Wake effects	Internal Wake Effects	0.0	**0.0**	3.9	**3.9**
	External Wake Effects	0.0		0.0	
	Total*	**14.2**		**17.4**	

* The total is the cumulated effect of the different losses and not their direct summation

Blade soiling and Degradation refers to the reduction of the blade's aerodynamic performance due to dust and/or insects. It also takes into account the future blade degradation attributed to wear of the blade's surface. The Cartwright project is not situated in a particularly dusty environment. This value is consistent with what is generally observed within the industry.

High wind hysteresis losses are caused by the control loop of the turbine around cut-out wind speed. They depend on the wind turbine design.

These estimations are based on the turbines' control loop specifications and high wind hysteresis simulations. Based on the available wind distribution at the mast, the loss induced by the hysteresis loop is 0.2%.

Icing losses happen in different ways: ice accumulation on blades alter their aerodynamic performance, nacelle-mounted instruments affected by ice give inaccurate readings and induce turbine control system errors, asymmetric icing causes mass or aerodynamic imbalance leading to vibrations that may force control systems to shut down the turbine. Icing can have different impact on the production of the turbine and the effect is site-specific. Some areas will be more affected by freezing rain or glaze ice and other regions are more prone to have rime ice or in-cloud icing.

Icing losses are estimated from the detection of icing events during met masts data quality control and translating the icing events into production losses. The level of ice is considered moderate as compared to other northern sites (up to 10% of icing losses).

Values should be taken with caution since no proven methodology is available and because the effect and characteristics of ice are highly site-specific. The uncertainty associated to these aspects is taken into account in the global uncertainty assessment.

Lightning has the potential to damage the turbine control system but also the blade integrity. Modern wind turbines have protection devices that most of the time allow continuous operation even after a lightning strike. There is however, a small chance that lightning will impact turbine operation. The lightning losses were estimated according to Environment Canada maps[5].

Low temperature shutdown losses depend on the local climate, the turbine design and the control algorithm. In cold climates, turbine shutdowns can be driven by low temperature detection, even if the wind is blowing. According to the manufacturer's specifications, the wind turbines with cold weather package have an operation threshold of - 40℃. The loss is estimated based on the long-term temperature data measured at Cartwright Environment Canada station.

Collection network loss is considered at the interconnection point. It takes into account various elements, including the length of the cables connecting the wind turbines to the substation and the losses in the substation itself. Losses depend on the design of these elements.

These losses have been estimated by Hatch according to previous experiences with similar project size and conditions. They should be confirmed when the design of the collection network is finalized.

[5] http://ec.gc.ca/foudre-lightning/default.asp?lang=En&n=42ADA306-1

Auxiliary power losses account for various subsystems of a wind turbine that require electrical power, such as control systems or heaters. All of these losses are not always accounted for in the power curve. For example, cold packages designed for cold climate wind turbines can require energy even when the turbine is stopped.

Based on Hatch's experience, an estimated value is used to account for the consumption of standard auxiliary systems. Specific losses have been added for the Cold Package system delivered with the wind turbines. They have been estimated by simulation according to the Cold Package specifications of the EWT900 and NPS100 Arctic wind turbines.

Wind turbine availability losses represent the percentage of time over a year that the turbine is unavailable for power production. Losses include regular maintenance time and unexpected turbine shutdowns. A given availability rate is normally guaranteed by utility-scale wind turbine manufacturers such as EWT (95%), but in the case of smaller wind turbines (NPS100), no availability warranty will be offered by the manufacturer.

Based on Hatch's experience on wind farms in similar conditions and technology for isolated sites, Hatch considers the estimate of 6.5% to be adequate for the Project with NPS100 units.

This estimation considers a standard maintenance schedule of 1 day per year per turbine, plus unscheduled repairs and delays due to site accessibility and weather conditions. This is based on information provided by the client that wind turbines will be considered as non-essential grid components and thus deficiencies will be considered as low priority, so that individual units may remain out of service for periods longer than normally considered.

Collection Network Availability: The collection network may be out of service, stopping energy delivery from the turbines to the grid. Collection network outage losses include shutdown time for scheduled maintenance and unexpected outages.

Based on the information provided by the client, the Cartwright based operators will manage the site and are expected to have the skills and manpower required to fix any collection system problem in a timely manner. The presence of a support team onsite has a positive impact on the availability of the collection network.

Grid availability losses depend on the utility distribution system quality and capacity. It represents the percentage of time over a year when the grid is not able to accept the energy produced by the wind turbines.

The value used assumes the wind turbines will be connected to the grid operated by NLH, which is assumed to be well maintained and operated.

Out-of-range Operation losses take into account the aspects usually not covered by the power curve warranty such as turbulence, wind shear and yaw errors. Parameters specific to the Project have been used to perform this loss estimate.

Wake Effect corresponds to the deficit in wind speed downstream of a wind turbine. Several models exist to quantify this effect in terms of induced energy losses. Hatch uses the Eddy Viscosity model which corresponds to a CFD calculation representing the development of the velocity deficit field using a solution of the Navier Stokes equations. Because of higher precision as compared to the Park model and recommendations from WindFarmer, the Eddy Viscosity model is used to assess to the wake of the Project. Wake losses are highly dependent on the layout, especially regarding the distance between the turbine and the layout's compactness.

One of the input in the wake losses calculation is the thrust curve which is provided by the turbine manufacturer for the Project turbine model under consideration.

No other wind farm currently exist in the vicinity of the project. In addition, no future wind farm that may impact the Project in terms of wake is planned. Thus there are no additional wake losses.

6. Conclusions and Recommendations

6.1 Objectives of Analysis

The purpose of this report is to present a full wind resource assessment for the Cartwright site, including the estimation of the forecasted annual energy production.

6.2 Data Quality and Adjustments

The wind data recovery rates at the monitoring site, for the analysis period, exceed industry standards, with a recovery rate from 95.3% to 99.3% for the primary anemometers and 95.4% for the primary wind vane.

The measured data were adjusted to long-term through correlation with Environment Canada's Cartwright station, located 4 Km away from the project area. The Long-term adjustment method was applied since it was considered to be the best method for producing a representative dataset for the expected life of the project.

6.3 Wind Resource

The annual average wind speed at the met mast is a result of the measurements and the long-term adjustment. These wind speeds are summarised in the table below for top anemometer and hub heights.

Table 6-1: Estimated Long-term Wind Speeds

Mast (Measurement Height)	Estimated Long-term Wind Speed at Measurement Height (m/s)	Estimated Long-term Wind Speed at Hub Height (m/s)	
		37 m	40 m
2605 (35 m)	7.0	7.3	7.3

The long-term dataset at the met mast was used to build the wind flow across the project area.

The complexity of the terrain is considered moderate and its effect on the modelled wind is not considered problematic.

6.4 Forecasted Energy Production

The preliminary turbine selection analysis specified two suitable turbine models: EWT900 and NPS100 Arctic. These models were proven to be best in class for cold and icy environments and suitable for wind-diesel generation in remote community.

The main results of the energy production modeling are summarised in the table below.

Table 6-2: Forecasted Annual Energy Production

Item	Layout 1 - EWT900	Layout 2 - NPS100 Arctic
WTG Rated Power (kW)	900	100
Number of Wind Turbines	1	5
Wind Farm Capacity (kW)	900	500
Annual Net Energy Production (MWh/yr)	**2,898**	**1,559**
Net Capacity Factor (P50) (%)	**36.7**	**35.6**

There remains some uncertainty regarding loss estimates, which should be reassessed as more information becomes available, particularly in relation to warranty contracts and maintenance schedules. Note that the Annual Net Energy Production represents the total forecasted energy production by the wind turbines. The effective energy production used to displace fuel will be a bit lower and vary depending on the chosen layout scenario (type and number of wind turbines), timewise power load and wind resource.

6.5 Recommendations

It should be noted that a number of additional studies and more detailed analysis will be required to refine and validate the turbine selected, the turbine position, the energy and losses.

The integration optimization report will show which turbine model is considered optimal for the Cartwright site based on energy cost, control capabilities and logistics and provide recommendations for further analysis and studies prior to implementation.

References

[1] International Energy Agency Programme, *Recommended practices for wind turbine testing and evaluation – Task 11: Wind Speed Measurement and Use of Cup Anemometer*, 1999

[2] National Renewable Energy Laboratory, *Wind Resource Assessment Handbook*, 1999

[3] International Electrotechnical Commission, *Wind Turbines - Part 1: Design Requirements*, IEC 61400-1, Ed. 3, 2005-08.

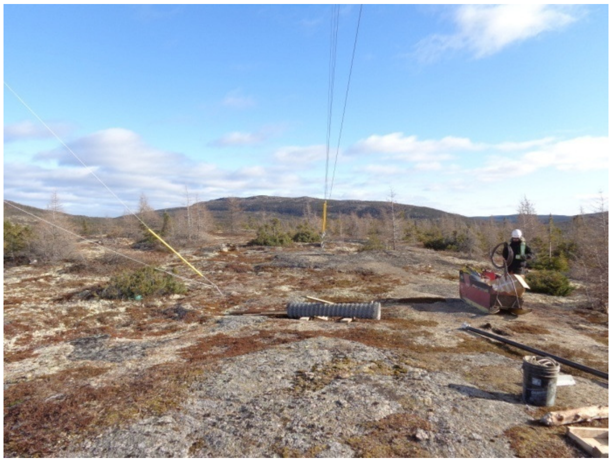
[4] International Electrotechnical Commission, *Wind Turbines - Part 12-1: Power performance measurements of electricity producing wind turbines*, IEC 61400-12-1, Ed. 1, 2005.

[5] A Practical Guide to Developing a Wind Project, *Wind Resource Assessment*, 2011

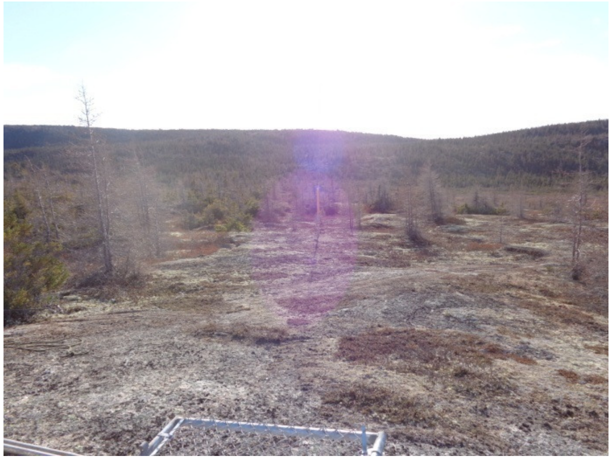
Appendix A

Views at Mast Sites

View Facing North



View Facing East



View Facing South

View Facing West

Figure – A1: Views from Base of Mast 2605

Appendix B

Wind Turbine Data

EWT DW52-900

The power curve and the thrust curve were provided to Hatch by Emergya Wind Technologies.

Table – B1: EWT Wind Turbine Performance Curves

Rotor Diameter: 51.5 m	**Hub Height: 40.0 m**	**Air Density: 1.225 kg.m^{-3}**	**Turbulence Intensity: N/A**
Wind Speed at Hub Height (m/s)	**Electrical Power (kW)**	**Wind Speed at Hub Height (m/s)**	**Thrust Coefficients**
0	0	0	0.000
1	0	1	0.000
2	0	2	0.000
3	7	3	0.866
4	30	4	0.828
5	69	5	0.776
6	124	6	0.776
7	201	7	0.776
8	308	8	0.753
9	439	9	0.722
10	559	10	0.692
11	698	11	0.613
12	797	12	0.516
13	859	13	0.441
14	900	14	0.368
15	900	15	0.296
16	900	16	0.241
17	900	17	0.199
18	900	18	0.168
19	900	19	0.143
20	900	20	0.124
21	900	21	0.109
22	900	22	0.096
23	900	23	0.085
24	900	24	0.075
25	900	25	0.067

NPS100

The power curve and the thrust curve were provided to Hatch by Northern Power.

Table – B2: NPS100 Wind Turbine Performance Curves*

Rotor Diameter: 20.7 m	**Hub Height: 37.0 m**	**Air Density: 1.225 kg.m^{-3}**	**Turbulence Intensity: N/A**
Wind Speed at Hub Height (m/s)	**Electrical Power (kW)**	**Wind Speed at Hub Height (m/s)**	**Thrust Coefficients**
0	0	0	0
1	0	1	0
2	0	2	0
3	0	3	0
4	3.7	4	1.072
5	10.5	5	0.963
6	19.0	6	0.866
7	29.4	7	0.820
8	41.0	8	0.754
9	54.3	9	0.687
10	66.8	10	0.616
11	77.7	11	0.548
12	86.4	12	0.491
13	92.8	13	0.436
14	97.3	14	0.391
15	100.0	15	0.347
16	100.8	16	0.316
17	100.6	17	0.286
18	99.8	18	0.261
19	99.4	19	0.239
20	98.6	20	0.222
21	97.8	21	0.206
22	97.3	22	0.194
23	97.3	23	0.184
24	98.0	24	0.175
25	99.7	25	0.167

* Power curve of the Northern Power 100 – standard model

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DA:da

EWT	Emergya Wind Technologies BV
	Engineering

Category:	Specification	Page 1 / 11
Doc code:	S-1000920	

Created by:	JT	Creation Date:	24-07-09
Checked by:	MB	Checked Date:	24-07-09
Approved by:	TY	Approved Date:	05-04-11

Title:

Specification

DIRECTWIND 52/54*900 Technical Specification

Revision	Date	Author	Approved	Description of changes
02	02-03-12	MB	TY	Format, minor text, blades, options
01	28-11-11	LE	TY	Corrections and drawings
-	-	-	-	-
-	-	-	-	-
-	-	-	-	-
-	-	-	-	-

Emergya Wind Technologies BV
Building 'Le Soleil' - Computerweg 1 - 3821 AA Amersfoort - The Netherlands
T +31 (0)33 454 0520 - F +31 (0)33 456 3092 - www.ewtinternational.com

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1 Introduction

This document provides a technical overview of the *DIRECTWIND* 52/54*900 Wind Turbine designed for the IEC class II/III application. It is to be read in conjunction with document S-1000921 "Directwind 52/54*900 Electrical Specification".

2 Technical Description

The *DIRECTWIND* 52/54*900 is a direct-drive, variable speed, pitch regulated, horizontal axis, three-bladed upwind rotor wind turbine.

The gearless direct-driven synchronous generator operates at variable speed. This is made possible by an actively controlled AC-DC-AC IGBT power converter connected to the grid. Benefits of this design are low maintenance, constant power output at wind speed above rated, and relatively low structural loads compared to constant-speed stall-controlled or constant-speed pitch-controlled wind turbines.

The generator is fully integrated into the structural design of the turbine, which allows for a very compact nacelle design. The drive-train makes use of only one main bearing, whereas classic designs have separately supported main shaft, gearbox and generator. All dynamically loaded interfaces from the blades to the foundation are sturdy flange connections with machined surfaces, and high tensile steel pre-stressed bolt connections are used.

2.1 Operation and safety system

The turbine operates automatically under all wind conditions and is controlled by an industrial PLC (Programmable Logic Controller). The cut-in wind speed is approximately 3m/s. When the rotational speed reaches the cut-in threshold, the power converter begins to deliver power to the grid.

The power converter controls the generator power output and is programmed with a power set-point versus rotor speed curve. Below rated wind speed the power output is controlled to optimise rotor speed versus aerodynamic performance (optimum λ-control). Above rated wind speed the power output is kept constant at rated value by PD-controlled active blade pitching.

The dynamic responses of the drive train and power controller are optimised for high yield and negligible electrical power fluctuations. The variable speed rotor acts as a flywheel, absorbing fluctuating aerodynamic power input. The turbine controllers are located in the rotor hub and the tower base (with remote IO in the nacelle) and carry out all control functions and safety condition monitoring. In the case of a fault, or extreme weather conditions, the turbine is stopped by feathering of the blades to vane position (blades swivelled to 90^0 with respect to rotor’s rotational plane). In case of power loss, an independent battery backup system in each blade ensures the blades are feathered.

In the case of less serious faults which have been resolved, or when extreme weather conditions have passed, the turbine restarts automatically to minimise downtime.

2.2 Generator

The multiple-pole, direct-drive generator is directly mounted to the hub. The stator is located in the non-moving outer ring and the wound pole, separately excited rotor rotates on the inner ring.

The generator is designed such that all aerodynamic forces are directly transferred to the nacelle construction without interfering with the generator-induced loads.

2.3 Power Converter

The power converter is an AC-DC-AC IGBT active switching converter. It controls the generator to operate in its optimum range, and maintains power quality to the grid. The inverter can produce unity power factor (cosΦ=1) to the grid under all load conditions. Power factor is also controllable within limits.

2.4 Rotor

The rotor is a three bladed construction, mounted up-wind of the tower. Rotational speed is regulated by active blade adjustment towards vane position. Blade pitch is adjusted using an electric servomotor on each of the blades.

Each blade has a complete, fully independent pitch system that is designed to be fail-safe. This construction negates the need for a mechanical rotor brake. The pitch system is the primary method of controlling the aerodynamic power input to the turbine.

At below rated wind speed the blade pitch setting is constant at optimum aerodynamic efficiency. At above rated wind speed the fast-acting control system keeps the average aerodynamic power at the rated level by keeping the rotor speed close to nominal, even in gusty winds.

The rigid rotor hub is a nodular cast iron structure mounted on the main bearing. Each rotor blade is connected to the hub using a pre-stressed ball bearing. It is sufficiently large to provide a comfortable working environment for two service technicians during maintenance of the pitch system, the three pitch bearings and the blade root from inside the structure.

2.5 Rotor blade set

The rotor blades are made of fibreglass-reinforced epoxy. The aerodynamic design represents state-of-the-art technology and is based on a pitch-regulated concept. No extenders are used and the aerodynamic design is optimal for this rotor diameter.

2.6 Main bearing

The large-diameter main bearing is a specially designed three row cylindrical roller bearing. The inner non-rotating ring is mounted to the generator stator. The outer rotating ring is mounted between the hub and generator rotor. The bearing takes axial and radial loads as well as bending moments. Entrance to the hub is through the inner-bearing ring. The bearing is greased by a fully automatic lubrication system controlled by the turbine PLC.

2.7 Nacelle

The nacelle is a compact welded construction which houses the yaw mechanism, a service hoist and a control cabinet. Both the generator and the tower are flanged to the nacelle. The geometry of the construction assures an ideal transfer of loads to the tower and, with the absence of a shaft and gearbox, results in a simple design ensuring easy personnel access.

2.8 Yaw system

The yaw bearing is an internally geared ring with a pre-stressed four point contact ball bearing. Electric planetary gear motors yaw the nacelle. The yaw brake is passive and is based on the friction of brake pads sitting directly on the bearing ring, keeping the yaw system rigid under most loading conditions.

2.9 Tower

The nacelle assembly is supported on a tubular steel tower, fully protected against corrosion. The tower allows access to the nacelle via a secure hinged access door at its base. The tower is fitted with an internal ladder with safety wire and optional climb assistance, rest platforms and lighting. Standard hub heights are 35, 40, 50 and 75 metres.

2.10 Anchor

The turbine is supported by a concrete foundation. The connection to this foundation is provided by means of a cast-in tube or rod anchor.

2.11 Control System

2.11.1 Bachmann PLC

The M1 controller perfectly combines the openness of a PC-based controller with the reliability of industrial hardware platforms. Designed to withstand the toughest ambient conditions it guarantees error-free use over long periods of time.

A modern system architecture designed for consistent network-capability permits the easy integration of the M1 into the environment of the controller and system peripherals. Real-time ethernet permits the real-time networking of the controllers, and the support of all standard Fieldbus systems permits the connection of standard external components.

2.11.2 DMS

DIRECTWIND Monitoring System – EWT's proprietary HMI featuring local monitoring and control at the turbine, integrated into a remote-access SCADA. DMS offers individual turbine control and total park monitoring and data logging from your Wind Turbine, Wind Park or internet access point.

2.12 Earthing and lightning protection

The complete earthing system of the wind turbine incorporates:

1. Protective earthing:
   A PE connection ensures that all exposed conductive surfaces are at the same electrical potential as the surface of the Earth, to avoid the risk of electrical shock if a person touches a device in which an insulation fault has occurred. It ensures that in the case of an insulation fault (a "short circuit"), a very high current flows, which will trigger an over-current protection device (fuse, circuit breaker) that disconnects the power supply.

2. Functional earthing:
   Earthing system to minimize and/or remove the source of electrical interference that can adversely affect operation of sensitive electrical and control equipment.

   A functional earth connection serves a purpose other than providing protection against electrical shock. In contrast to a protective earth connection, the functional earth connection may carry electric current during the normal operation of the turbine.

3. Lightning protection:
   To provide predictable conductive path for the over-currents in case of a lightning strike and electromagnetic induction caused by lightning strike and to minimize and/or remove dangerous situations for humans and sensitive electrical equipment.

Since the mechanical construction is made of metal (steel), all earthing systems are combined.

2.13 Options

The following options are available:

- Cold climate operation (rated for operation down to -40°C)
- Ice detection and/or prevention system
- Aviation lights
- Shadow flicker prevention
- Low Voltage Ride-through (LVRT)
- Service lift (75m tower only)
- G59 protection relay

3 Technical Data

Where data are separated by "/" this refers to the respective rotor diameter (52 / 54 m).

3.1 Wind and Site Data

Wind class	II / III according to IEC 61400 – 1
Max 50-year extreme	59.5 / 52.5 m/s
Turbulence class	A (I_{15} = 0.16)
Maximum flow inclination (terrain slope)	8°
Max ann. mean wind speed at hub height	8.5 / 7.5 m/s
Nominal air density	1.225 kg/m³

3.2 Operating Temperature

	Standard	Cold Climate
Min ambient operating	-20°C	-40°C
Max ambient operating	+40°C	+40°C

3.3 Cooling

Generator cooling	Air cooled
Converter cooling	Water or air cooled (configuration-dependent)

3.4 Operational Data

Cut in wind speed	3 m/s
Cut out wind speed	25 m/s
Rated wind speed	14 / 13.5 m/s
Rated rotor speed	26 rpm
Rotor speed range	12 to 33 rpm
Power output	900kW
Power factor	1.0 (adjustable 0.95 lagging to 0.95 leading) Measured at LV terminals

3.5 Rotor

Diameter	52 / 54 m
Type	3-Bladed, horizontal axis
Position	Up-wind
Swept area	2,083 / 2,290 m²
Power regulation	Pitch control; Rotor field excitation
Rotor tilt angle	5°

3.6 Blade Set

Type	PMC 24.5 / 25.8
Blade length	24.5 / 25.8 m
Chord at 22.0 m	0.879 m (90% of 24.5m blade radius)
Chord at 23.5 m	0.723 m (90% of 25.8m blade radius)
Chord Max at 5.5 m	2.402 m
Aerodynamic profile	DU 91, DU 98 and NACA 64618
Material	Glass reinforced epoxy
Leading edge protection	PU coating
Surface colour	Light grey RAL 7035
Twist Distribution	11.5^0 from root to 5.5m then decreases linearly to 0.29^0, then non-linearly to 0^0

3.7 Transmission System

Type	Direct drive
Couplings	Flange connections only

3.8 Controller

Type	Bachmann PLC
Remote monitoring	DIRECTWIND Monitoring System, proprietary SCADA

3.9 Pitch Control and Safety System

Type	Independent blade pitch control
Activation	Variable speed DC motor drive
Safety	Redundant electrical backup

3.10 Yaw System

Type	Active
Yaw bearing	4 point ball bearing
Yaw drive	3 x constant speed electric geared motors
Yaw brake	Passive friction brake

3.11 Tower

Type	Tapered tubular steel tower
Hub height options	HH = 35, 40, 50, 75 m
Surface colour	Interior: White RAL 9001, Exterior: Light grey RAL 7035

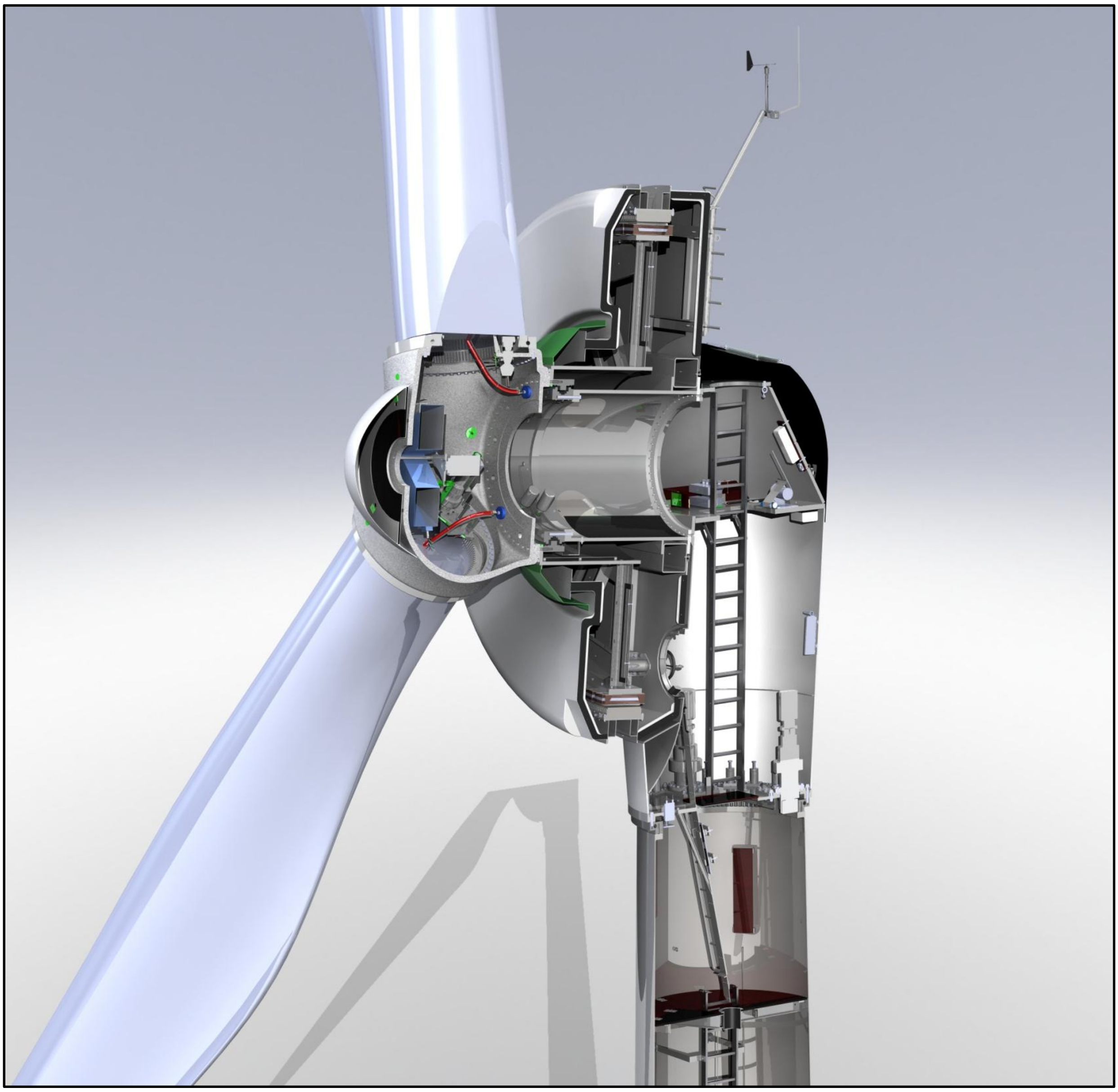
3.12 Mass Data

Hub	9,303 kg
Blade – each	1,919 / 1,931 kg
Rotor assembly	15,060 / 15,096 kg
Generator	30,000 kg
Nacelle assembly	10,000 kg
Tower HH35	28,300 kg
Tower HH40	34,000 kg
Tower HH50	46,000 kg
Tower HH75	86,500 kg

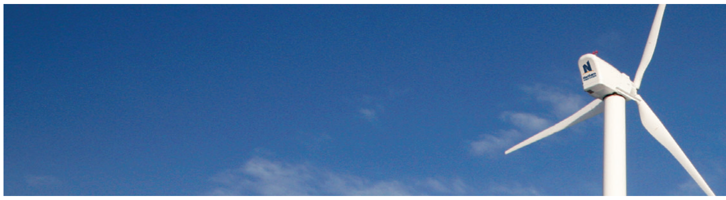
3.13 Service Brake

Type	Maintenance brake
Position	At hub flange
Calipers	Hydraulic 1-piece

APPENDIX 1: 3D image of main turbine components

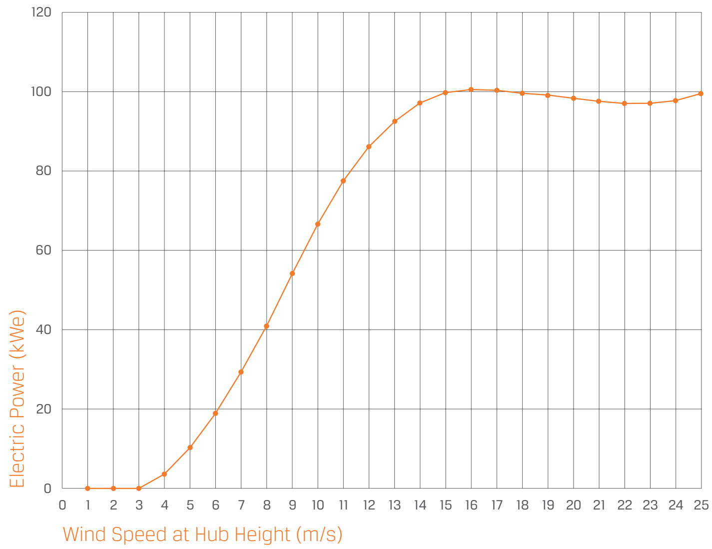


Specifications



Northern Power® 100

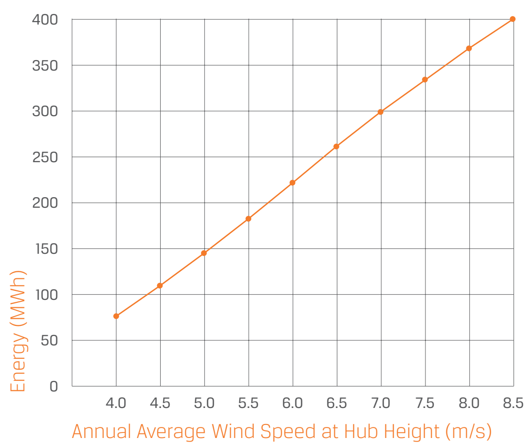
Power Curve: 21-Meter Rotor Standard Air Density (1.225 kg/m³)



Wind Speed (m/s)	Power (kWe)	Wind Speed (m/s)	Power (kWe)
1	0	14	97.3
2	0	15	100.0
3	0	16	100.8
4	3.7	17	100.6
5	10.5	18	99.8
6	19.0	19	99.4
7	29.4	20	98.6
8	41.0	21	97.8
9	54.3	22	97.3
10	66.8	23	97.3
11	77.7	24	98.0
12	86.4	25	99.7
13	92.8		

1 m/s = 2.24 mph

Annual Energy Production*: 21-Meter Rotor Standard Air Density, Rayleigh Wind Speed Distribution



Average Annual Wind Speed (mph)	Average Annual Wind Speed (m/s)	Annual Energy Output (MWh/yr)
8.9	4.0	77
10	4.5	110
11	5.0	145
12	5.5	183
13	6.0	222
15	6.5	260
16	7.0	298
17	7.5	334
18	8.0	368
19	8.5	400

*Annual energy production estimates assume standard conditions, 100% availability and no losses.

Northern
POWER SYSTEMS

Specifications

GENERAL CONFIGURATION	DESCRIPTION
Model	Northern Power® 100
Design Class	IEC IIA (air density 1.225 kg/m^3, average annual wind below 8.5 m/s, 50-yr peak gust below 59.5 m/s)
Design Life	20 years
Hub Height	37 m (121 ft) / 30 m (98 ft)
Tower Type	Tubular steel monopole
Orientation	Upwind
Rotor Diameter	21 m (69 ft)
Power Regulation	Variable speed, stall control
Certifications	UL1741, UL1004-4, CSA C22.2 No.107.1-01, CSA C22.2 No. 100.04, and CE compliant

PERFORMANCE	DESCRIPTION (standard conditions: air density of 1.225 kg/m^3, equivalent to 15°C (59°F) at sea level)
Rated Electrical Power	100 kW, 3 Phase, 480 VAC, 60/50 Hz
Rated Wind Speed	14.5 m/s (32.4 mph)
Maximum Rotation Speed	59 rpm
Cut-In Wind Speed	3.5 m/s (7.8 mph)
Cut-Out Wind Speed	25 m/s (56 mph)
Extreme Wind Speed	59.5 m/s (133 mph)

WEIGHT	DESCRIPTION
Rotor (21-meter) & Nacelle (standard)	7,200 kg (16,100 lbs)
Tower (37-meter)	13,800 kg (30,000 lbs)

DRIVE TRAIN	DESCRIPTION
Gearbox Type	No gearbox (direct drive)
Generator Type	Permanent magnet, passively cooled

BRAKING SYSTEM	DESCRIPTION
Service Brake Type	Two motor-controlled calipers
Normal Shutdown Brake	Generator dynamic brake and two motor-controlled calipers
Emergency Shutdown Brake	Generator dynamic brake and two spring-applied calipers

YAW SYSTEM	DESCRIPTION
Controls	Active, electromechanically driven with wind direction/speed sensors and automatic cable unwind

CONTROL/ELECTRICAL SYSTEM	DESCRIPTION
Controller Type	DSP-based multiprocessor embedded platform
Converter Type	Pulse-width modulated IGBT frequency converter
Monitoring System	SmartView remote monitoring system, ModBus TCP over ethernet
Power Factor	Set point adjustable between 0.9 lagging and 0.9 leading
Reactive Power	+/- 45 kVAR

NOISE	DESCRIPTION
Apparent Noise Level	55 dBA at 30 meters (98 ft)

ENVIRONMENTAL SPECIFICATIONS	DESCRIPTION
Temperature Range: Operational	-20°C to 50°C (-4°F to 122°F)
Temperature Range: Storage	-40°C to 55°C (-40°F to 131°F)
Lightning Protection	Receptors in blades, nacelle lightning rod and electrical surge protection
Icing Protection	Turbine designed in accordance with Germanischer Lloyd Wind Guidelines Edition 2003

All Specifications subject to change without notice.

NPS100SS-2222011-US

Appendix E:
Wind Resource Assessment Report – L'Anse-Au-Loup

Project Report

November 15, 2015

Newfoundland and Labrador Hydro
L'Anse au Loup Wind Project

Distribution

Trevor Andrew – NLH
Asim Haldar – NLH
Bob Moulton – NLH
Timothy Manning – NLH
Terry Gardiner – NLH
Louis Auger – Hatch
Dany Awad – Hatch
Ève-Line Brouillard – Hatch

Final Wind Resource Assessment Report

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Safety ● Quality ● Sustainability ● Innovation

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Safety ● Quality ● Sustainability ● Innovation

DISCLAIMER

Due diligence and attention was employed in the preparation of this report. However, Hatch cannot guarantee the absence of typographical, calculation or any other errors that may appear in the following results.

In preparing this report, various assumptions and forecasts were made by Hatch concerning current and future conditions and events. These assumptions and forecasts were made using the best information and tools available to Hatch at the time of writing this report. While these assumptions and forecasts are believed to be reasonable, they may differ from what actually might occur. In particular, but without limiting the foregoing, the long-term prediction of climatological data implicitly assumes that the future climate conditions will be identical to the past and present ones. Though it is not possible to definitively quantify its impact, the reality of the climate change is recognised by the scientific community and may affect this assumption.

Where information was missing or of questionable quality, Hatch used state-of-the-art industry practices or stock values in their stead. Where information was provided to Hatch by outside sources, this information was taken to be reliable and accurate. However, Hatch makes no warranties or representations for errors in or arising from using such information. No information, whether oral or written, obtained from Hatch shall create any warranty not expressly stated herein.

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DOCUMENT HISTORY

Revision	Date	Description
1	September 9, 2015	Final Version
2	November 15, 2015	Few edits based on comments from NLH on October 30, 2015 – Final Version

EXECUTIVE SUMMARY

In order to assess the potential of L'Anse au Loup site for wind power development, a wind resource assessment (WRA) was completed. The site is located near the community of L'Anse au Loup, Newfoundland and Labrador, Canada. The site was equipped with one met mast that is described in the table below.

Met Mast	Installation Date	Top Anemometer Height (m)	Elevation (m)	Data Collection* Starts…	Data Collection* Ends…
2604	October 5, 2013	35.0	179	November 01, 2013	October 31, 2014

* A 12 month period is selected to estimate the annual energy production

In the analysis, the quality control process demonstrated that the data recovery rates exceeded 95.2 % on all instruments which meets industry standards for wind measurement campaign. Erroneous or unreliable data were replaced with available redundant data from instruments on the same met mast since these are considered to be equivalent wind measurements.

The **wind speed** measured at the mast is **7.7 m/s** on average. The **winds are dominant from southwest to west and from northeast to east-northeast** across the site.

The wind **turbulence intensity** observed at the site is generally **moderate**.

Given the land cover and topography at the mast the **wind shear exponent**, equal to **0.19**, is consistent with the expected value.

Met Mast	Period	Annual Average of Measured Wind Speed* (m/s)	Annual Average of Measured Turbulence Intensity* (%)	Annual Wind Shear
2604	November 1, 2013 to October 31, 2014	7.7	13.1	0.19

** at Top Anemometer Height*

During the data quality control process, icing events were detected on anemometers and wind vanes. **Icing** occurred **6.8% of the time** at the site. Given the site elevation and the temperatures associated with these events, it is likely that about 44% of these events were caused by freezing rain and about 56% were caused by rime ice. Icing events mainly occurred during the months of December to February.

Temperature data were collected at the mast. The monthly averages range from **-13.7°C** in December to **13.4°C** in July, with an **annual average** of **-0.3°C** for the analysis period. The coldest 10-minute temperature recording during the data collection period was -32.2°C.

The **air density** was calculated at the mast according to the elevation and the local temperature. The annual value is **1.27 kg/m^3**.

The annual average power density is **620 W/m²**. The most powerful winds come from north to ENE, SW and WSW across the site.

In order to estimate the **long-term wind regime** at the site, several potential **reference stations** with historical data were selected.

The **Lourdes De Blanc Sablon A station** monitored by Environment Canada, located 30 km away from the potential wind farm site, was selected as the reference station for the long-term extrapolation of the data. The reference station data were then correlated to met mast 2604 and used to translate the short-term data into long-term estimates.

The long-term estimates were then extrapolated from measurement height to hub height.

Met Mast	Period	Estimated Long-term Wind Speed at Top Anemometer Height (m/s)	Estimated Long-term Wind Speed at Hub Height (m/s) at 40 m
2604	November 1, 2013 to October 31, 2014	8.0	8.2

The wind resource estimated at the mast was used to compute the wind flow across the project area. The wind flow was calculated with WAsP 11.01.0016 software, which is an appropriate model for the L'Anse au Loup project area which exhibits a moderate terrain complexity.

This wind flow was used to optimise the layout of the potential wind farm and to estimate the energy production with WindFarmer software.

A preliminary turbine selection analysis was completed and the Emergya Wind Technologies 900 kW (EWT900) wind turbine was selected. This model has proven technology in cold and icy environments and is suitable for wind-diesel generation in remote community.

A wind farm layout optimisation was completed taking in consideration energy production, information from the preliminary environmental screening and turbine extreme operating condition.

The main results of the energy production modeling are presented below. Additional losses include blade soiling, icing, collection network losses, auxiliary power consumption, wind turbines availability, high wind hysteresis, low temperature shutdown, collection network outage and grid availability.

Layout	Wind Farm Capacity (kW)	Net Energy Production (MWh/year)	Net Capacity Factor (%)	Wake Losses (%)	Additional Losses (%)
Layout 1 - EWT900	3600	11,651	36.9	1.2	13.7

Other energy production scenarios will be covered under separate portion of the wind penetration report.

1. Introduction

Hatch has been mandated by Newfoundland and Labrador Hydro (NLH) to carry out a wind resource assessment (WRA) for a potential wind project , located near the community of L'Anse au Loup, Newfoundland and Labrador, Canada.

The site was instrumented with one meteorological ("met") mast. The installation was completed on October 5, 2013. The mast was equipped with sensors at several heights to measure wind speed, wind direction and temperature. The analysed data cover a total measurement period of one year.

The second section of this report presents an overview of the site and the measurement campaign.

The third section presents the main characteristics of the wind climate.

The fourth section details the process used to translate the measured short-term data into long-term data.

The fifth section presents the methodology used to obtain the wind flow map over the project area. The wind flow map optimises the wind farm layout and helps determine monthly and annual energy production estimates. The key resulting values of these estimations are provided, including a description of the losses considered in the net energy calculation.

2. General Information

This section summarises general information about the site, the meteorological (met) mast installed and the measurement campaign.

2.1 Site Description

2.1.1 Site Overview

The community of L'Anse au Loup is located on the extreme south of Labrador in the middle of the strait of Belle-Isle, near the Quebec border. The surroundings of the community consists mainly of small hills covered by Nordic type vegetation with an average elevation of 150m above sea level.

Figure 2-1: Typical Landscape at the L'Anse au Loup Area

2.1.2 Mast Location

The location of met mast 2604 was chosen with agreement between Hatch and NLH. Hatch proceeded with the installation of the mast and followed industry standards [1].

Table 2-1 provides a description of the mast, including the exact coordinates and the elevation.

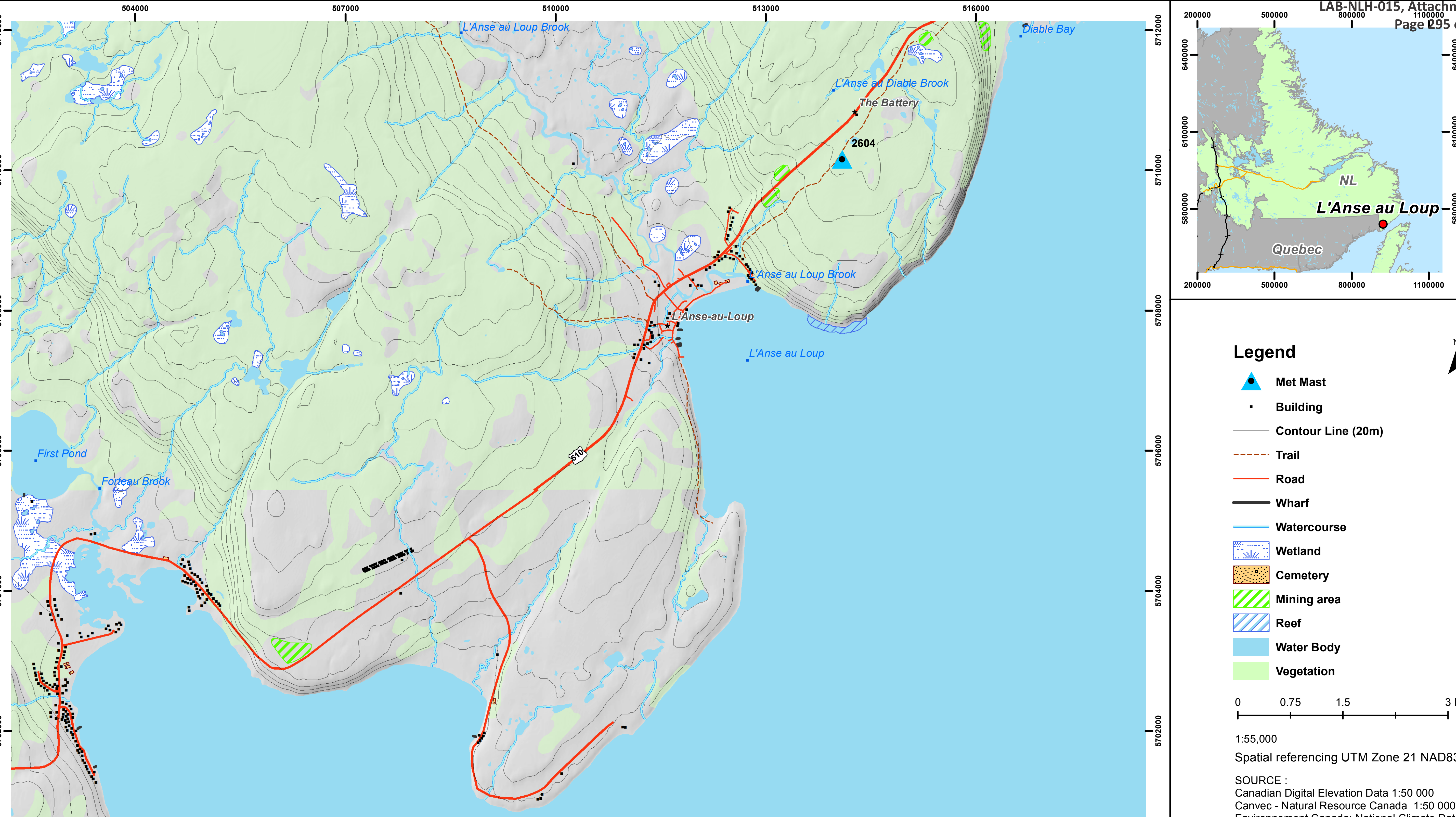
The location of the mast is shown on the map provided on next page.

Table 2-1: Met Mast Characteristics (Coordinate System: NAD83)

ID	Type	Side Length (m)	Height (m)	Latitude	Longitude	Elevation (m)
2604	Square Lattice	0.404	36	N 51° 32' 32.4"	W 56° 47' 48.6"	179

The L'Anse au Loup met mast (#2604) is located on a hill which dominate the community on its northeast side. The hill maximum height is approximately 200m and the tower is located on the top of a bog. Near the tower, there are patches of pine trees that are no more than 4m high.

Pictures have been provided in Appendix A with views in the four main geographical directions at the met mast.



Legend

- Met Mast
- Building
- Contour Line (20m)
- Trail
- Road
- Wharf
- Watercourse
- Wetland
- Cemetery
- Mining area
- Reef
- Water Body
- Vegetation

0 0.75 1.5 3 km

1:55,000

Spatial referencing UTM Zone 21 NAD83

SOURCE :
Canadian Digital Elevation Data 1:50 000
Canvec - Natural Resource Canada 1:50 000
Environnement Canada: National Climate Data
Google Earth Pro

NO.	DESCRIPTION	BY	CHK'D	APP'D	DATE

REVISIONS

REV.	ISSUE FOR	AUTH. BY	DATE

ISSUE AUTHORIZATION

HATCH

DESIGNED BY DANY AWAD
DATE: September 09,2015
DRAWN BY SLADJANA PAVLOVIC
DATE: September 09,2015
CHECKED BY DANY AWAD
DATE: September 09,2015

NALCOR

L'Anse au Loup Overview Map

SCALE BAR
REV. 1

2.2 Measurement Campaigns

The mast characteristics, instrumentation, installation dates and periods of data collection are provided in this section.

2.2.1 Installation and Collection Dates

The following table provides the date of mast installation and the period of data collection used in the analysis.

Table 2-2: Installation Date and Period of Relevant Data Collection

ID	Installation date	Date and time of first data used	Date and time of last data used
2604	October 5, 2013	November 01, 2013, 00:00 AM	October 31, 2014, 11:50 PM

2.2.2 Instrumentation

2.2.2.1 Sensors Mounting

The met mast was equipped with anemometers and wind vanes mounted on booms at several heights. The dimensions of the booms, their heights and orientations on the mast, were designed to comply with the best practices in wind resource assessment as specified in [1] and [2].

For the met mast, the instrument and installation parameters are provided in the table below. All instruments and met mast underwent regular maintenance checks.

Heated anemometers and wind vanes were installed to increase the data recovery rate during icing periods. An Autonomous Power System (A.P.S.) developed by Hatch was installed to power supply the heating instruments. The A.P.S. consists of a set of batteries charged by a small wind turbine through a controller.

Table 2-3: Installation Parameters of Instruments at the met Mast

Channel	ID	Height (m)	Type	Date Installed	Date Uninstalled	Calibrated / Heated	Primary / Redundant
Mast 2604							
Data Acquisition System							
N/A	N/A	N/A	NRG Symphonie PLUS3	Oct 05, 2013	July 17, 2015	N/A	N/A
Anemometers							
#1	**A1**	**35.0**	**NRG #40C**	**Oct 05, 2013**	**July 17, 2015**	**Yes / No**	**P**
#2	A2	35.0	NRG Icefree III	Oct 05, 2013	July 17, 2015	Yes / Yes	R
#3	A3	26.0	NRG #40C	Oct 05, 2013	July 17, 2015	Yes / No	P

Channel	ID	Height (m)	Type	Date Installed	Date Uninstalled	Calibrated / Heated	Primary / Redundant
#4	A5	26.0	RMYoung 5103-AP	Oct 05, 2013	July 17, 2015	Yes / No	R
#13	A4	17.0	NRG #40C	Oct 05, 2013	July 17, 2015	Yes / No	P
Wind Vanes							
#7	**V1**	**33.0**	**NRG Icefree III**	Oct 05, 2013	**July 17, 2015**	**No** / **Yes**	**P**
#8	V2	26.0	RMYoung 5103-AP	Oct 05, 2013	July 17, 2015	No / No	R
#9	V3	15.0	NRG #200P	Oct 05, 2013	July 17, 2015	No / No	R
Temperature Sensor							
#10	T	34.0	NRG #110S	Oct 05, 2013	July 17, 2015	No / No	P

Note: Lines in bold font correspond to the anemometer and wind vane considered as the principal instruments for wind characterisation at the mast location.

2.2.2.2 Data Acquisition System

For met mast 2604, the instruments were connected to a data acquisition system which stored the data on a memory card. The data were then sent to Hatch computer network by a satellite communication system every 3 days.

3. Meteorological Data Analysis

This section presents a comprehensive analysis of the data collected. In the first section, the quality of the data is reviewed. The characteristics of the wind measured at the mast are then presented in Section 3.2 through a number of relevant parameters:

- monthly and annual average wind speeds;
- wind speed distribution;
- wind direction distribution;
- wind shear;
- turbulence intensity;
- 50-year recurrence wind speed.

In the final section, other climatic information such as measured temperature, calculated air density, wind power density and icing events is presented and discussed.

3.1 Quality Control

The quality and completeness of the data are key factors that determine the reliability of the wind resource assessment.

Data are collected periodically from the met masts and the quality of the data is analysed. This is done by applying a variety of logical and statistical tests, observing the concurrent readings from different instruments and relating these observations to the physical conditions at the site (e.g. wind shading, freezing potential, etc.). The process is semi-automated: the tests are implemented in a computer program developed by Hatch, but the expertise of quality analysts are required to accept, reject or replace data. There are many possible causes of erroneous data: faulty or damaged sensors, loose wire connections, broken wires, data logger malfunction, damaged mounting hardware, sensor calibration drift, icing events and different causes of shading (e.g. shading from the mast or from any obstacles at the site). A list of the possible error categories used during quality control is presented in Table 3-1. Data points that are deemed erroneous or unreliable are replaced by redundant data when available, or removed from the dataset.

The data recovery rate for the analysis period is then calculated for each of the instruments using the following equation:

$$\text{Data recovery rate}\,(\%) = \frac{\text{Number of valid observations}}{\text{Number of potential observations}} * 100$$

The “Number of valid observations” is evaluated once erroneous or unreliable data are replaced with available redundant data. The “Number of potential observations” is the theoretical maximum number of measurements that could be recorded during the analysis period. A high data recovery rate ensures that the set of data available is representative of the wind resource over the measurement period.

Table 3-1: Quality Control Table

Error Categories
Unknown event
Icing or wet snow event
Static voltage discharge
Wind shading from tower
Wind shading from building
Wind vane deadband
Operator error
Equipment malfunction
Equipment service
Missing data (no value possible)

3.1.1 Data Replacement Policy

Erroneous or unreliable data were replaced with available redundant data from instruments on the same met mast since these are considered to be equivalent wind measurements. Replacements were done directly or by using a linear regression equation. Direct replacement is applied to anemometers when the replaced and replacing instruments are of the same model, calibrated, at the same height, and well correlated. Direct replacement is also applied to wind vanes as long as they are well correlated.

An acceptable percentage of the dataset is replaced by equivalent instruments (e.g. A1-A2: 10% of replacement) and it is considered to have a small impact on the uncertainty of the measurements.

3.1.2 Recovery Rates

The following table presents the recovery rates calculated for each instrument after quality control and after replacements have been completed according to the replacement policy.

Table 3-2: Instruments Data Recovery Rates

Mast ID	A1	A3	A4	V1	T
2604	99.0%	97.9%	95.2%	98.2%	100.0%

Note that the recovery rates for the following instruments are identical, given the replacement policy:

- A1 and A2; A3 and A5
- V1, V2 and V3

3.1.3 *Data History*

The data recovery rates exceed industry standards [5]. A number of data were affected for short periods of time by usual effects, such as shading effect and short period of icing events, and were removed. An occasional high discrepancy on V3 was found as compared to other vanes due to high standard deviation in the dominant wind direction.

3.2 Wind Characteristics

3.2.1 Annual and Monthly Wind Speed

The monthly wind speeds measured at each anemometer are shown in the following figures for mast 2604. The data are presented in two formats (see Figure 3-1 and Figure 3-2):

a) for all instruments, the averaged monthly wind speed measured;
b) for A1, all monthly wind speeds also reported.

Although the results for anemometers A2 and A5 are presented, they will not be considered in further calculations as these sensors were used primarily for quality control and replacement purposes.

As expected, the data confirm that wind speeds increase with height above ground level (see section 3.2.4 for a description of wind shear). Furthermore, the graphs show the seasonal pattern of wind, which decreases towards summer months and increases towards winter months.

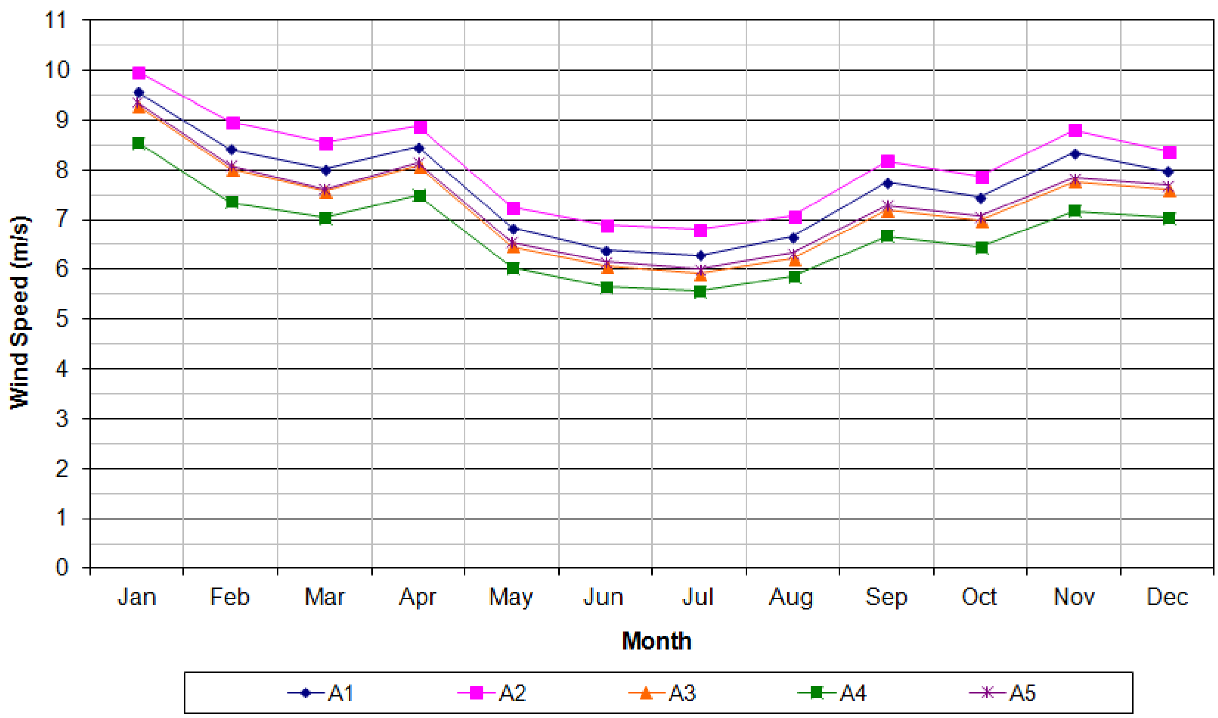


Figure 3-1: Averaged Monthly Wind Speeds for Each Anemometer at Mast 2604, November 1, 2013 to October 31, 2014

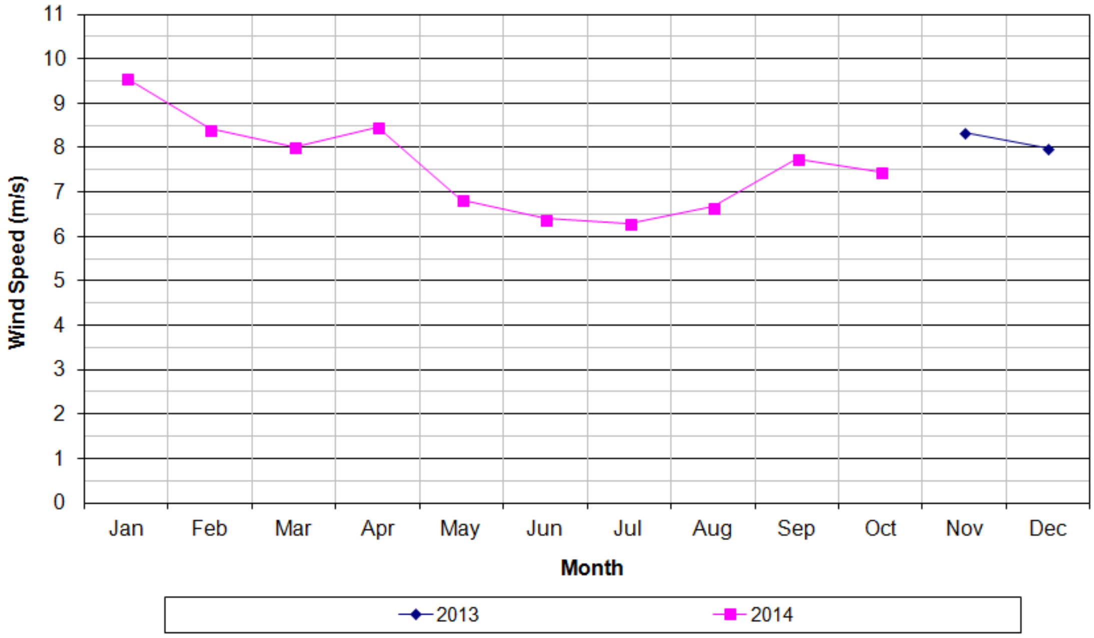


Figure 3-2: Monthly Wind Speeds Measured at the Top Anemometer at Mast 2604, November 1, 2013 to October 31, 2014

The following table provides, the average wind speed and the maximum 1-second gust observed, and specifies the averaging method used and the period of data considered. The averaging method varies as it depends upon the available dataset:

- Annual: average of the wind speed recorded over one or more full years.
- Annualised: the annualised wind speed is a weighted wind speed that is calculated from all available monthly average wind speeds–e.g. if 2 values are available for January and only one is available for February, the February value will have twice the weight of each January value in the final average.
- Average: due to insufficient data collection, the annual average wind speed was not calculated. The value given is the average of all available data.

Table 3-3: Wind Speed Characteristics at the Mast

Mast	Top Anemometer Height (m)	Period	Average Wind Speed (m/s)	Maximum 1-second gust (m/s)	Method
2604	35.0	November 1, 2013 to October 31, 2014	7.7	41.1	Annual

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3.2.2 *Wind Speed Frequency Distribution*

The frequency distribution of wind speeds helps to evaluate how much power is contained in the wind (power is proportional to the cube of the wind speed). Wind turbines will produce more power as the wind speed increases (until reaching the "rated" value). Thus, as the frequency of higher wind speeds increases, more power can be produced.

Annual frequency distributions generally exhibit a Weibull shape that is controlled by its "scale factor" (closely linked to the average wind speed) and its shape factor.

The wind speed frequency distribution graph is presented below for the mast[1].

2604, anemometer A1, November 01, 2013 to October 31, 2014

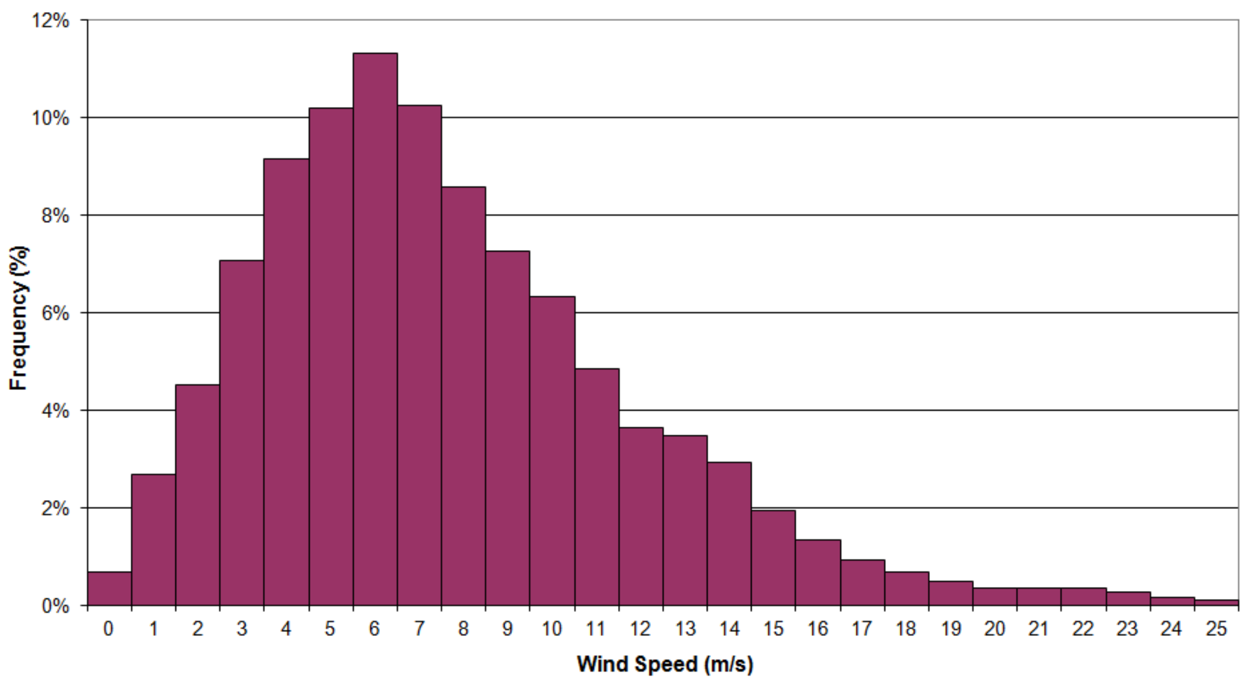


Figure 3-3: Wind Speed Frequency Distribution Graph

3.2.3 *Wind Rose*

The wind rose graph is presented below. The wind rose is divided into the conventional 16 compass sectors (22.5º wide sectors). Note that all compass orientations referenced in this report are based on the true geographic north, rather than the magnetic north.

[1] The 0 m/s wind speed bin indicates the fraction of the total number of measurements with a wind speed between 0 to 0.5 m/s. The other bins are 1 m/s wide and centered on the integer value (e.g.: the 1 m/s wind speed bin indicates the fraction with a wind speed between 0.5 to 1.5 m/s).

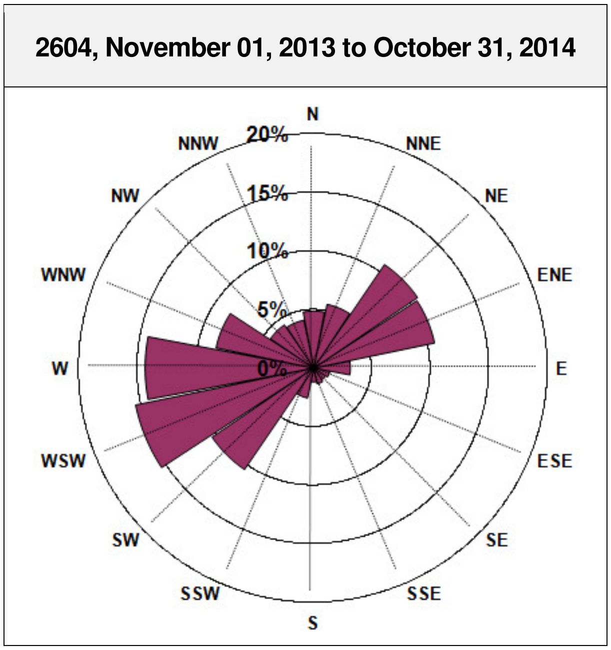


Figure 3-4: Wind Rose Graph

The wind rose indicates that a significant proportion of the wind blows from southwest to west and from northeast to east-northeast, across the project area.

Note that wind roses are not adjusted to the long-term. Moreover, differences in wind directions between the levels of measurement are small enough to be neglected. As a consequence, the present wind rose will be considered as representative of the long-term wind rose at hub height.

3.2.4 Wind Shear

Wind speeds typically increase with height above the ground, because the frictional drag decreases with altitude. The increase in wind speed with height is referred to as wind shear and is commonly modeled either by a logarithmic law or by a power law.

When the power law is used, the wind shear can be quantified by a wind shear exponent. “Rough” surfaces, such as forested lands and urban areas, have a more pronounced frictional drag than “smooth” surfaces, such as a snow covered field or grasslands–the former will be associated with higher wind shear exponents. Over a smooth, level, grass-covered terrain, the wind shear exponent is typically around 0.14; over snow or calm sea it may be as low as 0.10; and over urban areas or tall buildings it may be as high as 0.40.

The roughness is not the only surface property that has a direct effect on the wind shear. When there is dense vegetation, the vertical wind speed profile is displaced vertically above the canopy, thereby displacing the level of zero wind speed to a certain fraction of the vegetation height above the ground. The “displacement height” is defined as the height at which the zero wind speed level is displaced above the ground. The displacement height is taken into account in all wind shear estimations.

Finally, large topographic variations over short distances may also impact the wind vertical profile and thus affect the wind shear.

Hatch recommends using the log law to estimate the wind shear at mast locations. Internal studies have shown that the accuracy of the wind shear estimate is slightly improved with the log law when compared to the power law. When available, three wind speed measurements, each at a different height, are used and a log law curve is fitted through the average wind speeds at these heights. With the log law, the parameter that reflects roughness is called the roughness length, instead of the wind shear exponent. However, an equivalent wind shear exponent is calculated between the top anemometer height on a mast and the hub height for easier interpretation.

The equivalent wind shear exponent presented in this report was calculated between the top anemometer height of the mast and hub height of 40 m. The calculation was based on the measured wind speed at the anemometer height and the wind speed extrapolated to hub height by the log law method. The log law parameters were determined by fitting a logarithmic curve through the average measured wind speeds at the three measurement heights.

The average equivalent wind shear exponent is reported in the following table.

Based on our knowledge about the vegetation in the area of the mast, this value conforms to expected results.

Table 3-4: Average Wind Shear at the Mast

Mast	Period	Wind Shear
2604	November 01, 2013 to October 31, 2014	0.19

3.2.5 Turbulence Intensity

Turbulence characterises the gustiness of wind or high frequency changes in wind speed and direction (high turbulence is typical of very irregular wind flows, contaminated by whirls or vortices). Turbulence increases in areas with very uneven terrain and behind obstacles, such as buildings. In wind farms, it interferes with the effective operation of the wind turbines and increases their wear and tear.

The measurement of turbulence is expressed in terms of turbulence intensity, which is the standard deviation of the wind speed divided by the mean wind speed, over a given period. Turbulence intensity is expressed as a percentage. In the present study, the standard deviation and mean speed values are calculated from 1 second wind speed data averaged over a 10 minute period.

Turbulence intensity is more erratic and more difficult to quantify at low wind speeds. As a consequence, only wind speeds in excess of 4 m/s are used to calculate of the turbulence intensity. This threshold is consistent with IEC standards for wind turbine power performance measurements [4].

The turbulence intensity value was calculated with the top anemometer data.

The average turbulence intensity is reported in the next table. This value is considered moderate according to the reference values defined in reference [2][2]. It is expected that turbulence will decrease with height, as the effect of obstacles and surface roughness will diminish.

Table 3-5: Average Turbulence Intensity at the Mast

Mast	Anemometer used	Period	Turbulence Intensity (%)
2604	A1	November 01, 2013 to October 31, 2014	13.1

3.2.6 50-year recurrence wind speed

The selected wind turbine Emergya Wind Technologies 900 kW (EWT900) is designed to survive a certain level of loading caused by an extreme wind event. Based on the specification provided by the manufacturer, the extreme survival wind speed at hub height is 59.5 m/s (see Appendix B).

At least 7 years of data at the met mast location or a nearby reference station are required. The Gumbel distribution was used to predict the once-in-fifty-year extreme wind speed. The data were extrapolated to hub height of 40 m with a power law exponent of 0.11 suggested for gusts as per Wind Energy Handbook [2] and IEC 61400-1 standard.

In the case of L'Anse au Loup project, the met mast has only 18 months of data. Thus, data from Lourdes De Blanc Sablon A Environment Canada station were used and based on hourly data at 10 metres height. The data cover the period from 2000 to 2014. The 50-year recurrence maximum wind speeds were estimated to be 50.8 m/s at 40 m which respect the turbines' specifications.

3.3 Other Climatic Data

3.3.1 Temperature

Temperature was measured at a height of 34 m. The following table presents the average monthly and annual temperature measured. The coldest 10-minute temperature recording measured during the data collection period was -32.2°C in the morning of January 3, 2014.

Table 3-6: Average Monthly and Annual Temperatures

Mast ID	Monthly Air Temperature (°C)												Annual
	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	
2604	-12.2	-13.1	-11.0	-2.6	1.9	8.4	13.4	12.3	8.8	4.9	-1.9	-13.7	-0.3

[2] Low levels of turbulence intensity are defined as values less than or equal to 0.10, moderate levels are between 0.10 and 0.25, and high levels are greater than 0.25. This classification is for meteorological turbulence only; it should not be used in comparison with IEC models. Meteorological turbulence should not be used to establish the wind turbine class.

3.3.2 Air Density

Wind energy is directly proportional to the air density. Consequently, the amount of energy produced by a wind turbine will also be directly proportional to the air density at the turbine location. Air density decreases with increasing temperature, decreasing pressure and increasing altitude.

Based on the measured temperatures and the standard barometric pressure of 101.3 kPa at sea level, the monthly average air densities were calculated. Note that to correct for changes in atmospheric pressure with height, the calculations account for the site elevation. The values were calculated over the entire analysis period reported in Table 2-2.

Table 3-7: Monthly and Annual Average Air Density

Mast ID	Monthly Air Density (kg/m³)												Annual
	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	
2604	1.32	1.32	1.31	1.27	1.25	1.22	1.20	1.21	1.22	1.24	1.27	1.32	1.27

3.3.3 Power density

Wind speed, wind direction and air density data can be combined to provide information about the average power density at mast location. Wind power density indicates how much energy is available at a given instant for conversion by a wind turbine[3]. For example, strong winds in the winter, when the air is colder and denser, will have a higher power density (i.e. carry more energy) than the same strong winds in the summer. Though power is an instantaneous value, it is calculated as an average over a given period of time.

Tables of the power density distribution per direction and per month were produced at the top anemometer height and are presented below.

At mast 2604, the most powerful winds come from north to ENE, SW and WSW, and appear in winter months. The annual average power density is 620 W/m² at 35 m.

Table 3-8: Table of Wind Power Density per Direction, November 1, 2013 to October 31, 2014

Wind Power Density per Direction (W/m²)															
N	NNE	NE	ENE	E	ESE	SE	SSE	S	SSW	SW	WSW	W	WNW	NW	NNW
1423	928	746	668	171	144	118	137	125	253	818	775	403	287	383	617

Table 3-9: Table of Wind Power Density per Month, November 1, 2013 to October 31, 2014

Wind Power Density per Month (W/m²)												Annual Average
Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	
1120	935	771	638	372	280	236	354	505	568	922	669	620

[3] Note that the units "W/m²" refer to m² of rotor swept area.

3.3.4 Icing Events

Icing affects the operation of wind turbines. Icing on any exposed part of the turbine can occur in the form of wet snow (generally associated with temperatures between 0°C to 1°C), super-cooled rain or drizzle (that can occur at temperatures between 0°C to -8°C, but mostly in the upper part of this range), or in-cloud icing (that can occur below - 2°C). Losses during production due to ice occur in several ways:

- Ice accumulation on the blades alters their aerodynamic profile, reducing the power output.

- Nacelle-mounted instruments accumulate ice and give inaccurate readings. The turbine control system may detect a fault condition due to the turbine output being much greater than expected. This expectation is based on the wind speed. As a result, the turbine will be shut down until the ice is removed from the instruments and the turbine is reset.

- Asymmetric icing causes mass or aerodynamic imbalance leading to vibrations. Control systems that sense vibrations will normally shut down when these vibrations occur.

Icing is a complex phenomenon and predicting icing from meteorological conditions is notoriously difficult, requires a good set of observations from a number of meteorology variables, and can be misleading. As no reliable instrument is presently available to detect and quantify icing events for the purpose of estimating their impact on wind energy production, Hatch uses several tests during data quality control to detect icing events: detection of unusual standard deviations or changes with time of wind speeds and directions, comparison of measurements from a heated anemometer and a standard anemometer at the same level, in parallel with the measurement of temperature.

These tests cannot distinguish between the different types of icing, but a rough approximation can be done by utilising the temperature ranges measured during icing events. Therefore, in the following estimate, we will consider two categories: “glaze”, which is assumed to include wet snow, super-cooled rain and drizzle, and “rime ice”, which is assumed to include in-cloud icing and the very low temperature part of super-cooled rain or drizzle. The threshold of -5°C is used to differentiate between rime ice (below -5°C) and glaze (above -5°C).

The following table presents the estimated number of icing events in a month and the type of event assumed to occur in the project area. This estimate is based on the average of icing events detected on the mast during the measurement campaign.

Table 3-10: Estimated Hours of Icing Events, October 5, 2013 to April 30, 2015

	January	February	March	April	May	June	
Hours	164	135	46	39	2	0	
Rime	50%	80%	100%	0%	0%	-	
Glaze	50%	20%	0%	100%	100%	-	
	July	**August**	**September**	**October**	**November**	**December**	**Annual Average**
Hours	0	0	0	8	53	149	594
Rime	-	-	-	0%	10%	60%	56%
Glaze	-	-	-	100%	90%	40%	44%

4. Long-term Wind Speed at Hub Height

The previous section presented the analysis of the wind regime as it was measured by the met mast installed on the project site. However, to forecast the energy production of a wind power plant, wind data that represent the historical wind conditions at the site are required. Unfortunately, wind resource assessments are generally conducted for a limited number of years, often no more than one or two years, which is not sufficient to capture the year-to-year variability of wind. For example, in North America, the annual average wind speed exhibits a standard deviation of about 6% (or 1σ from a normal distribution) of the long-term average wind speed. Hence, the maximum deviation from the average wind speeds could reach as much as 20% (or 3.3σ). Consequently, it is necessary to translate the measured short-term data into long-term data. This is done through a correlation/adjustment process that makes reference to a meteorological station where historical data are available.

Moreover, when the top anemometers of the met masts are mounted at a lower height than the expected hub height of the wind turbines, the long-term data must also be extrapolated from these anemometer heights to the wind turbine's hub height.

The long-term projection process is presented in the next section and is followed by the extrapolation to hub height.

4.1 Long-term Projection

When required, selecting a reference dataset to perform a long-term correlation and adjustment is determined by the following process:

- A quality assessment of the potential long-term reference stations for the site (history, similarity of the local climate with regards to the meteorology mast climate, etc.);

- A quality assessment of the correlation equations obtained with acceptable long-term reference stations and the measured data for the concurrent period;

- A comparison of the long-term correlation results obtained with all acceptable reference stations;

- A crosscheck of the resulting long-term adjustments with the measured data and the long-term trends at nearby reference stations or at a regional level;

Once the reference dataset is selected, it is used to adjust the met mast data to long-term conditions. This can be achieved either by synthesizing non existing years of data at the met mast site or by applying an adjustment factor to the measured data in order to better reflect the reference period. The process is as follows:

- The measured data from the met mast is correlated with the reference dataset;

- If the correlation parameters meet the synthesis criteria, then data are synthesized at the measurement mast for the complete reference data period; this method is referred to as the Measure-Correlate-Predict (MCP);

- If the criteria are not met but a good correlation can still be obtained with hourly or daily intervals, then the measured dataset is scaled up (or down) to long-term using the reference long-term average wind speed and the correlation equation obtained; this method is referred to as the Long-term Adjustment;

- If no correlation can be clearly established between a reference site and the met mast site, the measured data stay unchanged.

4.1.1 *Selection of reference dataset*

The present section summarises the results of the analysis.

Among the possible set of reference stations, one station was selected and considered suitable for the long-term projection of the data at the met mast. This station is Lourdes De Blanc Sablon A monitored by Environment Canada (EC). The location of this station is given in the table below. The station was moved in December 2014 to a new location nearby the airport, thus data up to end of 2014 were used in the current analysis.

Table 4-1: Identification of the Long-term Reference

Name	ID (Available Data Period)	Instruments Height (m)	Latitude	Longitude	Elevation (m)
Lourdes De Blanc Sablon A	7040813 (1970-2014)	10.0	N 51° 27' 00.0"	W 57° 11' 00.0"	37.2
	7040815 (2014-2015)		N 51° 26' 31.0"	W 57° 11' 10.0"	

4.1.2 *Long-term Adjustment*

The long-term adjustment consists of:

- Correlating short term data at the met mast with short term data at the reference station;

- Using the obtained linear regression equation, Y = m X + b, where X represents the long-term average wind speed at the reference station and Y is the estimated long-term average at the met mast;

- Applying an adjustment factor (to speed up or scale down) to the met mast short term data in order to obtain an average wind speed equal to the estimated long-term average at met mast (i.e. Y).

For mast 2604, which displayed 18 months of data recorded, the long-term adjustment method was used for the long-term projection.

The wind speed data of the met mast were correlated to the concurrent wind speed data at the long-term reference station Lourdes De Blanc Sablon A. Good correlation results were obtained with daily average values (R^2 greater than or equal to 0.7 is good correlation, above 0.85 is excellent). The results of the correlations are given in the following table. Linear regression equations were used to compare the data, where *m* is the slope of the equation, *b* is the intercept, and R^2 is the coefficient of determination.

Table 4-2: Correlations between Reference Station and met mast Wind Speeds

Reference Station	Met Mast	Correlation Period		Daily Wind Speed Correlations		
		Beginning	End	m	b	R^2
Lourdes De Blanc Sablon A	**2604**	November 1, 2013	October 31, 2014	0.942	2.8	0.74

The regression equations were then used to estimate the long-term average wind speed at the mast as a function of the long-term wind speed at the reference station. The estimated long-term average at the Lourdes De Blanc Sablon A station is 5.5 m/s. It was estimated by averaging all annual averages over the period 2000 to 2014. The results are presented in the following table.

Table 4-3: Long-term Adjustment factor at the met mast

Met Mast	Wind Speed over Correlation Period (m/s)	Long-term Annual Wind Speed (m/s)	Adjustment Factor (%)
2604	7.7	8.0	4.5%

Finally, the 10-minute measured data recorded at the met mast were scaled by the adjustment factor to reflect the long-term value. In terms of the wind direction data, the one-year dataset for the met mast remained untouched. As a result, the mast has a set of wind speeds and wind directions that are the best estimate of the long-term wind regime.

4.2 Extrapolation to Hub Height

The wind shear exponent, calculated with the measured data, was used to adjust the dataset to hub height. The results are presented in the following table.

Table 4-4: Estimated Long-term Wind Speed at Hub Height*

Met Mast	Estimated Long-term Wind Speed at Top Anemometer Height (m/s)	Estimated Long-term Wind Speed at Hub Height of 40 m (m/s)
2604	8.0	8.2

* Estimated using the calculated wind shear

5. Wind Resource Mapping and Projected Energy Production

Met masts provide a local estimate of the wind resource. Met mast locations are chosen based on how representative they are of the project site and in particular for potential wind turbine locations. However, since the number of met masts is usually limited compared to the expected number of wind turbines, it is necessary to build a wind flow map based on these measurements to extend the wind resource assessment to the whole project area.

Wind modeling software, such as MS-Micro and WAsP, are known to produce erroneous wind flows over complex terrain. In this case, Hatch applies a method based on the Ruggedness Index (RIX) to calculate the wind flow for each mast dataset while correcting errors on wind speed[4]. All produced wind flows are then merged by a distance-weighting process. When the RIX correction is not applicable, wind flows are calculated with each mast dataset and simply merged together by a distance-weighting process, without a RIX correction.

Once the wind flow map is built, it is possible to optimise the size and layout of the foreseen wind farm for the project, and then to calculate the projected energy production. When necessary, wind turbine hub heights as well as met mast heights are corrected with the estimated displacement height. This is computed to account for the influence of trees on the wind flow (see section 3.2.4). These corrections result in an effective hub height for each wind turbine.

The wind flow and energy production are calculated with specialised software that require, apart from the met masts long-term data, background maps that contain the information on topography, elevation, roughness lengths (related to the land cover) and potential obstacles. This is also used in conjunction with the wind turbine characteristics. Finally, wind farm losses must be estimated in order to complete the energy estimate.

The first part of this section introduces the information and the methodology used to calculate the wind flow.

The next part will present the optimisation process and the results in terms of energy production.

The software used to map the wind resource and to calculate the energy production include:

- WAsP Issue 11.01.0016 from Risø for wind resource mapping;
- Wind Farmer Issue 4.2.2 from Garrad Hassan for layout optimisation and energy production calculations.

5.1 Background Data

5.1.1 Topography and elevation

The topographic and elevation data come from files provided by the National Topographic Data Base (NTDB) and the NASA’s Shuttle Radar Topography Mission (SRTM).

The contour line interval is 5 m within the project area and 20 m outside.

[4] Bowen, A.J. and N.G. Mortensen (2004). WAsP prediction errors due to site orography. Risø-R-995(EN). Risø National Laboratory, Roskilde. 65 pp.

5.1.2 Roughness

The base map for roughness lengths was determined from land cover information included in the NTDB and CANVEC files. This map was then checked and corrected using satellite imagery from Google Earth. Around mast location and wind turbines, pictures and information noted during site visits were also used to check and modify the land cover information. The spatial resolution considered for the roughness lengths is 30m.

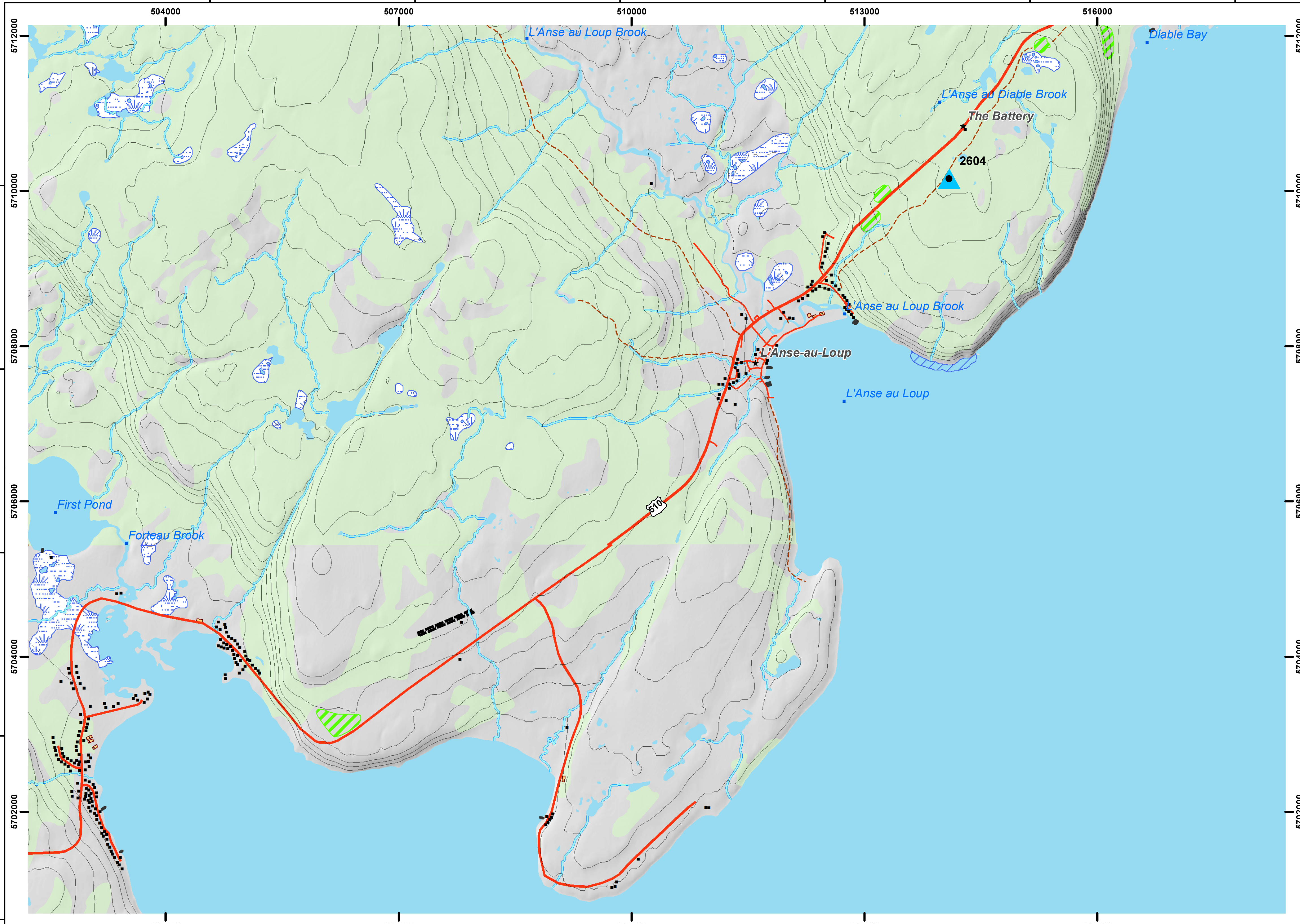
The following table details the roughness lengths used by land cover category.

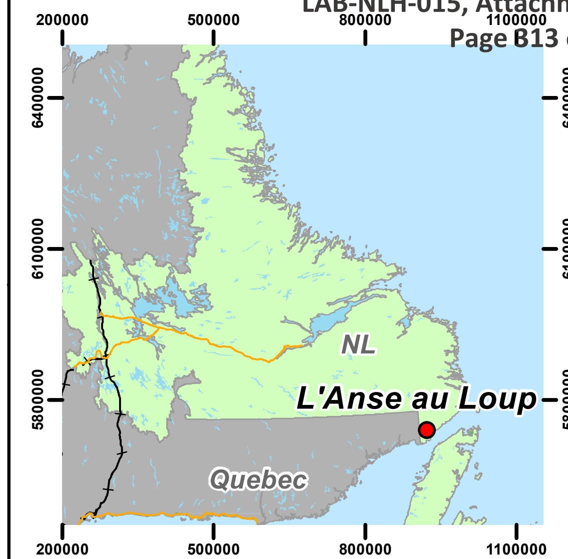
Table 5-1: Roughness Lengths Categories

Land Cover Type	Roughness Length (m)
Open farmland, high grass	0.04
Water	0
Forest	0.6

5.1.3 Background Map

The background map, showing topography and contour lines is provided on the next page.





Legend

- Met Mast
- Building
- Contour Line (20m)
- Trail
- Road
- Wharf
- Watercourse
- Wetland
- Cemetery
- Mining area
- Reef
- Water Body
- Vegetation

N

0 0.75 1.5 3 km

1:55,000

Spatial referencing UTM Zone 21 NAD83

SOURCE :
Canadian Digital Elevation Data 1:50 000
Canvec - Natural Resource Canada 1:50 000
Environnement Canada: National Climate Data
Google Earth Pro

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L'Anse au Loup
Overview Map

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5.2 Wind Flow Calculation

5.2.1 Terrain Complexity

The wind flow is produced over semi-complex terrain. Wind modeling software, such as MS-Micro (used in Windfarm) and WAsP, are known to produce erroneous wind flows over complex terrain. Depending on the topography, predicted wind speeds can be over or under-estimated at a given location. Errors can reach more than 20% in very complex areas.

In the present case, the complexity of the terrain is considered moderate and its effect on the modelled wind is not considered problematic.

5.2.2 Parameters

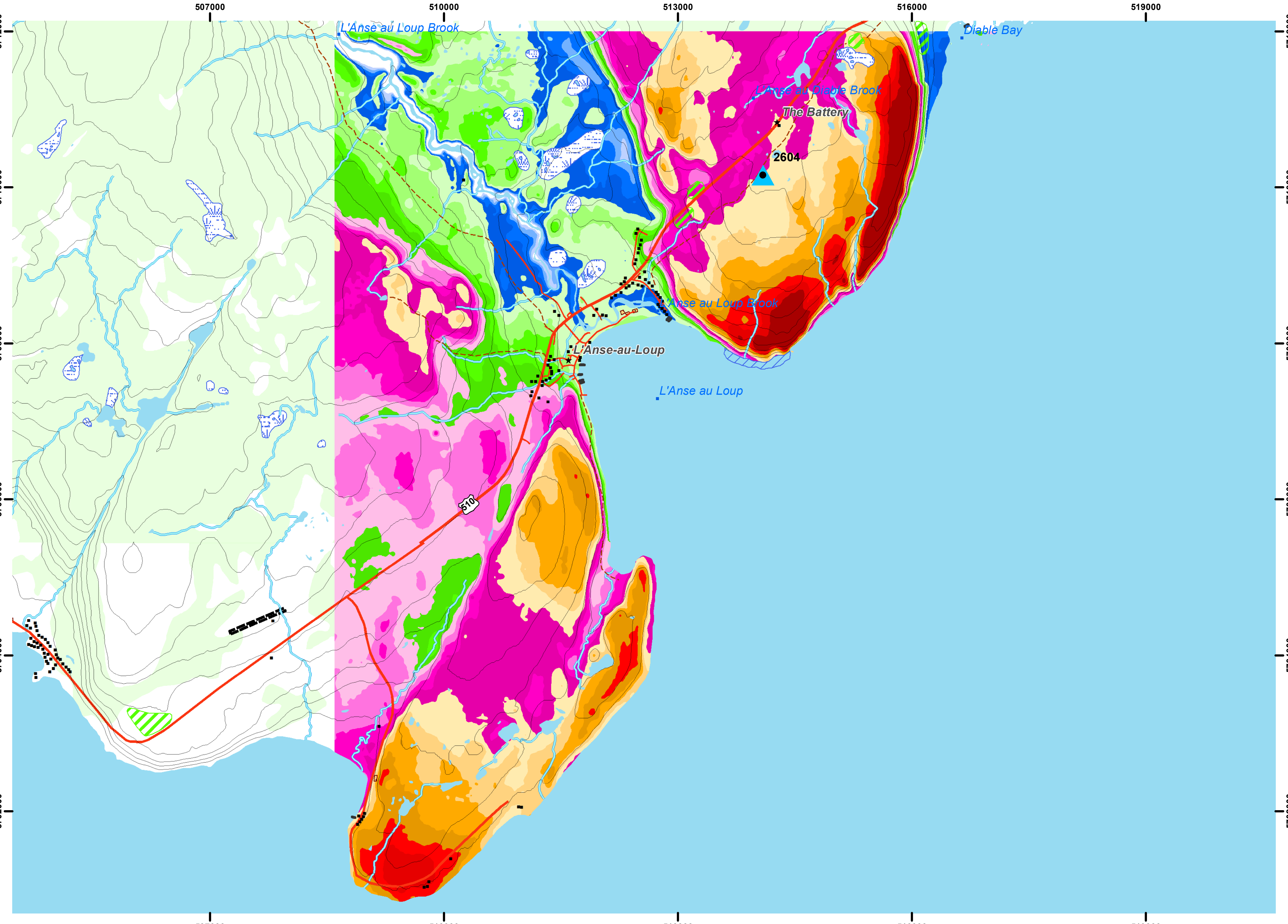
The following parameters were used to calculate the wind flow map.

Table 5-2: Wind Flow Calculation Parameters

Parameter	Value
Wind Resource Grid Spatial Resolution	50 m
Calculation Area	8.8 km by 12.0 km
Reference Mast	2604
Reference Height	Top Anemometer Height
Calculation height	37 m
Vertical Extrapolation Method	Based on measured wind shear
Roughness Change Model	WAsP Standard Model

5.2.3 Results

The wind flow map used for layout optimisation and energy production estimates is presented on the next page.



Legend

- Met Mast
- Building
- Contour Line (20m)
- Trail
- Road
- Wharf
- Watercourse
- Wetland
- Cemetery
- Mining area
- Reef
- Water Body
- Vegetation

WindFlow (37m)

m/s

- < 5
- 5 - 5.25
- 5.25 - 5.5
- 5.5 - 5.75
- 5.75 - 6
- 6- 6.25
- 6.25 - 6.5
- 6.5 - 6.75
- 6.75 - 7
- 7 - 7.25
- 7.25 - 7.5
- 7.5 - 7.75
- 7.75 - 8
- 8 - 8.25
- 8.25 - 8.5
- 8.5 - 8.75
- 8.75 - 9
- 9 - 9.25
- 9.25 - 9.5
- 9.5 <

N

0 0.75 1.5 3 km

1:55,000

Spatial referencing UTM Zone 21 NAD83

SOURCE :
Canadian Digital Elevation Data 1:50 000
Canvec - Natural Resource Canada 1:50 000
Environnement Canada: National Climate Data
Google Earth Pro

Wind resource map created by Hatch with WAsP 11.01.0016
Height of calculation: 37 m
Spatial resolution of wind resource grid: 50 m
Source file: LAAL_2604_GridWRG_37m_WF2.asc
Source of data used to create the wind flow:
Topographic data are provided by the Center for Topographic Information (NRCan) and the NASA's Shuttle Radar Topography Mission (SRTM).
Meteorological data were collected from mast 2604, located 4 km on average from the center of the map, between 01/11/2013 and 31/10/2014.
Data were controlled by Hatch. Met data were adjusted for long term with reference to station Environment Canada Lourdes De Blanc Sablon A # 7040813 (reference period 2000-2014). It is believed that the present map gives a reliable overall picture of the wind resource. However, ` it is advised to confirm any information obtained from this map at any location by on-site measurements.

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L'Anse au Loup Windflow 2

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REV. 1

5.3 Forecasting Energy Production

The layout was initially designed in order to maximise energy production. Turbines were spread out inside the project boundaries to minimise wake effects. The preliminary environmental screening and turbine extreme operating conditions also contributed to set the turbine locations.

5.3.1 Preliminary Turbine Selection

A preliminary turbine selection was performed using Windographer software by comparing the performance of different turbines at the location of the met mast, where the dataset was recorded. The main parameters used for the comparison were the capacity factor of the wind turbine for the site specific conditions as well as the turbine purchase cost. Only turbines that meet the following criteria were considered:

- Site's turbine and turbulence class (IEC class II)
- Extreme wind and weather conditions (operation down to -40℃). The minimum 10-minute temperature recording of -32.2℃ during the monitoring campaign confirms the site conditions are within the operating range of the turbine.
- Turbine capacity ranges from 500 kW to 1,000 kW to meet the community load
- Wind turbine's dimensions and weight versus crane capacity and accessibility

Hub heights of about 40 m to 50 m were used for this preliminary analysis.

Standard losses considered include: 12.5% technical losses and 2% wake losses.

The following table provides a summary of the turbine comparison.

Table 5-3: Windographer Results at the Mast Location

Turbine type	Turbine Class	Hub height (m)	Turbine Capacity (kW)	Mean Energy Output (MWh/yr)	Capacity Factor (%)	Turbine purchase cost ($)
Aeronautica AW/Siva47-500	IB/IIA	47	500	1,745	39.9	1,632,000
EWT DW52-500 (EWT500)	IIA	37	500	1,951	44.5	1,990,000
EWT DW52-900 (EWT900)	IIA	40	900	2,666	33.8	2,000,000

The capacity factors listed above in table 5-3 are taken from Windographer and may change as a function of the site's optimized layout and should only be used for turbine comparison.

Due the lack of proven experience in remote arctic conditions, the Aeronautica wind turbine model was discarded from the analysis. EWT wind turbines have been installed and are operating in similar site conditions in Nome, Alaska for EWT or in Kasigluk, Alaska for Northern Power and were thus further compared as part of the analysis.

The average community load at L'Anse au Loup during the project lifetime is around 3000 kW. The following table shows the results of the WindFarmer optimization models using the required number of turbines to meet that load. The turbines were ranked based on their capacity factor, energy output and simple payback.

Table 5-4: Preliminary Turbine Selection Results

Turbine type	Number of wind turbine required	Total Capacity (kW)	Gross Energy Output (MWh/yr)	Gross Capacity Factor (%)	Total purchase cost (Million $)	Ranking
EWT500	6	3000	14,530	55.3	11.940	2
EWT900	**4**	**3600**	**13,500**	**42.8**	**8.000**	**1**

* Based on the gross energy output at 30 cents/kWh and the turbine purchase cost only.

Based on information provided by EWT, the 500 kW wind turbine has the same foundation design as the 900 kW machine and nearly the same price ($10,000 difference). Because of the similar turbine costs of the EWT models, from a financial point of view, the EWT900 becomes the most suitable having the lowest simple payback, and would also benefit from potential lower constructability and BOP cost.

The EWT900 turbine is the model that meets the wind class of the site and has proven technology for cold and icy environments.

Even though a more detailed turbine selection exercise will be required in later phase of the project, the EWT900 is considered suitable candidate turbine in order to complete the preliminary energy estimates for the potential L'Anse au Loup project.

5.3.2 Layout Optimization

The following section shows the WindFarmer modeling results which further refines the energy estimates for the turbines selected at the potential turbine positions and to confirm the capacity factor values. The table below outlines the parameters and constraints assumed to influence optimisation.

Table 5-5: Layout Optimisation Parameters and Constraints

Parameter / Constraint	Value
Annual Air Density	1.27 kg.m^{-3} at 213 m.a.s.l.
Turbulence Intensity	13.1% at mast 2604 ***Note***: *average value for information, the turbulence intensity is actually entered by wind-speed bins and by direction for energy prediction calculation*
Exclusion areas	Due to the lack of information in regard to setbacks for wind energy projects in Newfoundland and Labrador, general restriction rules were used: - 500 m from habitations

Parameter / Constraint	Value
	- 100 m from public roads - 50 m from lakes and rivers - 2 km by 1 km buffer zone from the airport track
WTG Minimum Separation Distance	Elliptical separation: Minimum of 5 rotor diameters on long axis Minimum of 3 rotor diameters on short axis Bearing of long axis: 240 degrees
WTG Model	EWT900
WTG Rated Power (kW)	900
WTG Rotor Diameter (m)	51.5
WTG Hub Height (m)	40.0
WTG Power Curve	See Appendix B
WTG Thrust Curve	See Appendix B
Number of WTG's	4
Wind Farm Capacity (kW)	3600
Wake Model	Modified Park Model used for optimisation and Eddy Viscosity Model for final energy calculation as recommended by Garrad Hassan
Maximum Slope	10 degrees
Optimization Strategy	Layout designed in order to maximise energy production.

The project layout is presented at the end of this section.

The layout is still considered preliminary. Land restrictions, communication corridors, noise and visual impacts, and other site-specific matters need to be evaluated through a detailed environmental assessment. Available land, road and collection system costs are also issues that will need to be addressed before the site layout can be finalized.

5.3.3 Energy production

Once the optimised layout has been produced, the energy production for each wind turbine is calculated. When necessary, wind turbine hub heights as wells as met mast heights are corrected with the estimated displacement height. This is computed to account for the influence of trees on the wind flow. These corrections result in an effective hub height for each wind turbine.

The calculation was executed with the power curves and thrust curves used for the optimisation and presented in Appendix B. The additional losses are described in the next section.

Note that air density is corrected by the software for each turbine location according to its elevation.

The following table is a summary of the estimated energy production. Detailed energy figures are presented per wind turbine on the next page.

Table 5-6: Wind Farm Energy Production Summary

Item	Layout 1 - EWT900
WTG Rated Power (kW)	900
WTG Rotor Diameter (m)	51.5
WTG Hub Height (m)	40.0
Number of Wind Turbines	4
Wind Farm Capacity (kW)	3600
Mean Free Wind Speed across Wind Farm (m/s)	8.4
Average Wake Losses (%)	1.2
Energy Production Before Additional Losses* (MWh/yr)	13,500
Capacity Factor Before Additional Losses* (%)	42.8
Additional Losses (%)	13.7
Net Energy Production (P50) (MWh/yr)	**11,651**
Net Capacity Factor (%)	**36.9**

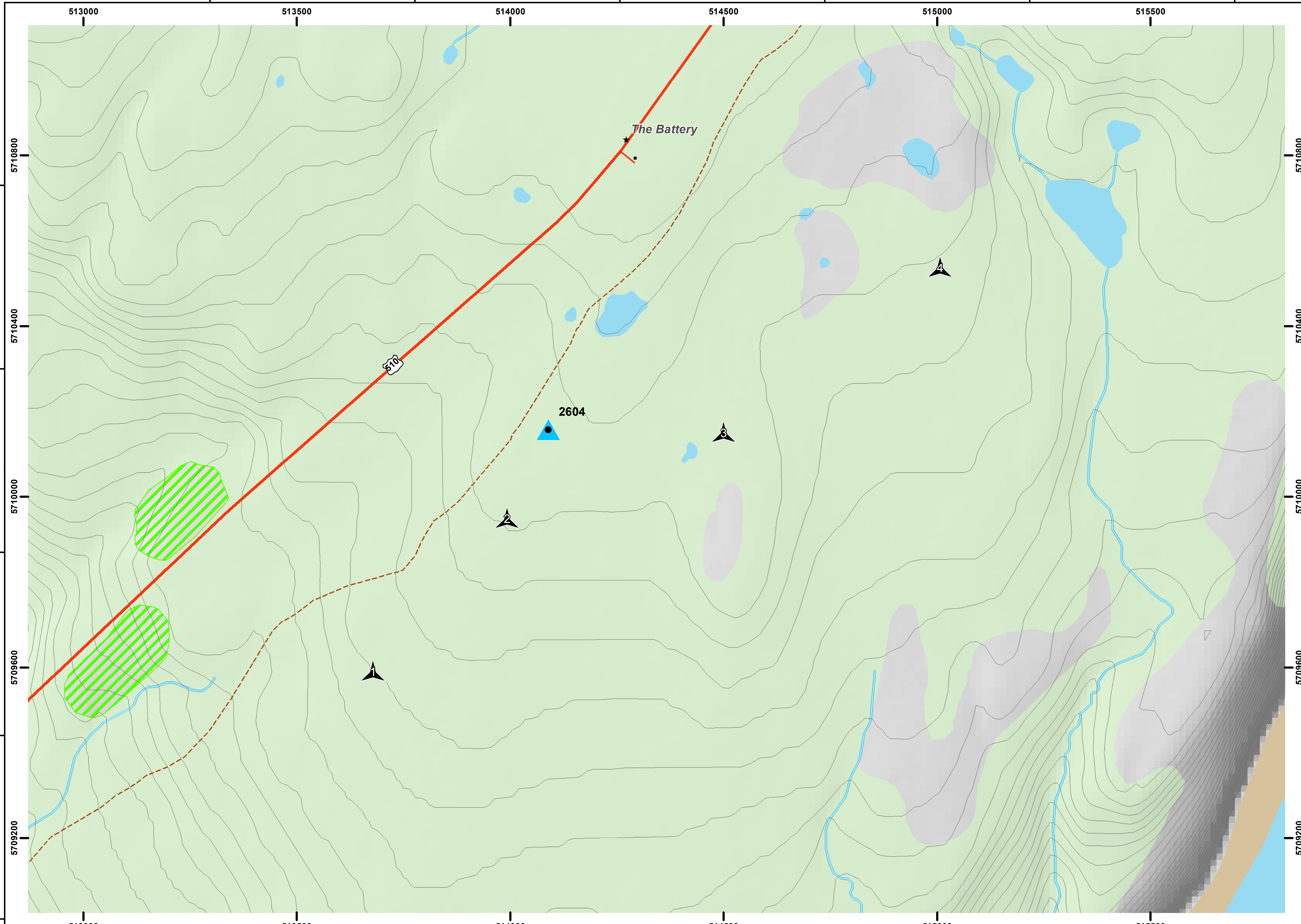
* Includes topographic effect and wake losses

Table 5-7: Forecasted Energy Production at Wind Turbines

Turbine ID	Easting (m)	Northing (m)	Altitude (m)	Mean Free Wind Speed (m/s)	Gross Energy Production* (MWh / Year)	Wake Losses (%)	Gross Energy - Wake* (MWh / Year)	Turbulence Intensity** (%)
Layout 1 - EWT900								
1	513678	5709592	165	8.5	3418	0.8	3391	14.3
2	513992	5709950	180	8.5	3389	1.3	3344	14.5
3	514500	5710152	182	8.5	3395	1.7	3335	14.6
4	515007	5710539	179	8.7	3458	0.8	3430	14.1

* Gross energy production includes topographic effect; "Gross energy – Wake" includes topographic effect and wake losses.

** Turbulence Intensity includes ambient turbulence and incident turbulence. The values represent true meteorological turbulence; they should not be compared directly with IEC models and consequently should not be used to establish the wind turbine class.



Legend

- Wind Turbine
- Met Mast
- Building
- Contour Line (5m)
- Trail
- Road
- Watercourse
- Mining area
- Water Body
- Vegetation

N

0 125 250 500 m

1:10,000

Spatial referencing UTM Zone 21 NAD83

SOURCE :
Canadian Digital Elevation Data 1:50 000
Canvec - Natural Resource Canada 1:50 000
Environnement Canada: National Climate Data
Google Earth Pro

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Turbine model: EWT DW52-900
Number of turbines: 4
Site capacity: 3600 KW
Turbine rated power: 900 KW
Hub height: 40 m
File reference: LAAL_WF2_Lay1.txt

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DRAWN BY
SLADJANA PAVLOVIC
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DANY AWAD
DATE: September 09,2015

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L'Anse au Loup
Layout 1

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5.3.4 *Losses*

This section provides a description of the estimated losses included in the P50 estimate. These losses include environmental, electrical, availability, turbine performance losses and wake effects. The P50 is defined as the exceedance probability that denotes the level of annual wind-driven electricity generation that is forecasted to be exceeded 50% of the year. Half of the year's output is expected to surpass this level, and the other half is predicted to fall below it. Loss estimates should be reviewed as more detailed information becomes available.

The losses considered are presented in the following table and described hereafter.

Table 5-8: Wind Farm Losses

Loss Category	Loss Type	Losses (%)	
		Layout 1 - EWT900	
Environmental	Blade Soiling and Degradation	1.0	**4.5**
	High Wind Hysteresis	0.2	
	Icing	3.0	
	Lightning	0.0	
	Low Temperature Shutdown	0.4	
Electrical	Collection Network	1.3	**3.1**
	Auxiliary power	1.8	
Availability	Wind Turbine Availability	5.0	**5.8**
	Collection Network Outage	0.6	
	Grid Availability	0.2	
Turbine Performance	Out-of-range Operation	1.0	**1.0**
Wake effects	Internal Wake Effects	1.2	**1.2**
	External Wake Effects	0.0	
	Total*	**13.7**	

* The total is the cumulated effect of the different losses and not their direct summation

Blade soiling and Degradation refers to the reduction of the blade's aerodynamic performance due to dust and/or insects. It also takes into account the future blade degradation attributed to wear of the blade's surface. The L'Anse au Loup project is not situated in a particularly dusty environment. This value is consistent with what is generally observed within the industry.

High wind hysteresis losses are caused by the control loop of the turbine around cut-out wind speed. They depend on the wind turbine design.

These estimations are based on the turbines' control loop specifications and high wind hysteresis simulations. Based on the available wind distribution at the mast, the loss induced by the hysteresis loop is 0.2%.

Icing losses happen in different ways: ice accumulation on blades alter their aerodynamic performance, nacelle-mounted instruments affected by ice give inaccurate readings and induce turbine control system errors, asymmetric icing causes mass or aerodynamic imbalance leading to vibrations that may force control systems to shut down the turbine. Icing can have different impact on the production of the turbine and the effect is site-specific. Some areas will be more affected by freezing rain or glaze ice and other regions are more prone to have rime ice or in-cloud icing.

Icing losses are estimated from the detection of icing events during met masts data quality control and translating the icing events into production losses. The level of ice is considered moderate as compared to other northern sites (up to 10% of icing losses).

Values should be taken with caution since no proven methodology is available and because the effect and characteristics of ice are highly site-specific. The uncertainty associated to these aspects is taken into account in the global uncertainty assessment.

Lightning has the potential to damage the turbine control system but also the blade integrity. Modern wind turbines have protection devices that most of the time allow continuous operation even after a lightning strike. There is however, a small chance that lightning will impact turbine operation. The lightning losses were estimated according to Environment Canada maps[5].

Low temperature shutdown losses depend on the local climate, the turbine design and the control algorithm. In cold climates, turbine shutdowns can be driven by low temperature detection, even if the wind is blowing. According to the manufacturers' specifications, the wind turbines with cold weather package have an operation threshold of - 40℃. The loss is estimated based on the long-term temperature data measured at Lourdes De Blanc Sablon A Environment Canada station.

Collection network loss is considered at the interconnection point. It takes into account various elements, including the length of the cables connecting the wind turbines to the substation and the losses in the substation itself. Losses depend on the design of these elements.

[5] http://ec.gc.ca/foudre-lightning/default.asp?lang=En&n=42ADA306-1

These losses have been estimated by Hatch according to previous experiences with similar project size and conditions. They should be confirmed when the design of the collection network is finalized.

Auxiliary power losses account for various subsystems of a wind turbine that require electrical power, such as control systems or heaters. All of these losses are not always accounted for in the power curve. For example, cold packages designed for cold climate wind turbines can require energy even when the turbine is stopped.

Based on Hatch's experience, an estimated value is used to account for the consumption of standard auxiliary systems. Specific losses have been added for the Cold Package system delivered with the wind turbines. They have been estimated by simulation according to the Cold Package specifications of the EWT900 wind turbine.

Wind turbine availability losses represent the percentage of time over a year that the turbine is unavailable for power production. Losses include regular maintenance time and unexpected turbine shutdowns. A given availability rate is normally guaranteed by utility-scale wind turbine manufacturers such as EWT (95%).

This estimation considers a standard maintenance schedule of 1 day per year per turbine, plus unscheduled repairs and delays due to site accessibility and weather conditions. This is based on information provided by the client that wind turbines will be considered as non-essential grid components and thus deficiencies will be considered as low priority, so that individual units may remain out of service for periods longer than normally considered.

Collection Network Availability: The collection network may be out of service, stopping energy delivery from the turbines to the grid. Collection network outage losses include shutdown time for scheduled maintenance and unexpected outages.

Based on the information provided by the client, the L'Anse au Loup based operators will manage the site and are expected to have the skills and manpower required to fix any collection system problem in a timely manner. The presence of a support team onsite has a positive impact on the availability of the collection network.

Grid availability losses depend on the utility distribution system quality and capacity. It represents the percentage of time in a year when the grid is not able to accept the energy produced by the wind turbines.

The value used assumes the wind turbines will be connected to the grid operated by NLH, which is assumed to be well maintained and operated.

Out-of-range Operation losses take into account the aspects usually not covered by the power curve warranty such as turbulence, wind shear and yaw errors. Parameters specific to the Project have been used to perform this loss estimate.

Wake Effect corresponds to the deficit in wind speed downstream of a wind turbine. Several models exist to quantify this effect in terms of induced energy losses. Hatch uses the Eddy Viscosity model which corresponds to a CFD calculation representing the development of the velocity deficit field using a solution of the Navier Stokes equations. Because of higher

precision as compared to the Park model and recommendations from WindFarmer, the Eddy Viscosity model is used to assess to the wake of the Project. Wake losses are highly dependent on the layout, especially regarding the distance between the turbine and the layout's compactness.
One of the input in the wake losses calculation is the thrust curve provided by the turbine manufacturer for the Project turbine model under consideration.

No other wind farm currently exists in the vicinity of the project. In addition, no future wind farm that may impact the Project in terms of wake is planned. Thus, there are no additional wake losses.

6. Conclusions and Recommendations

6.1 Objectives of Analysis

The purpose of this report is to present a full wind resource assessment for the L'Anse au Loup site, including the estimation of the forecasted annual energy production.

6.2 Data Quality and Adjustments

The wind data recovery rates at the monitoring site, for the analysis period, exceed industry standards, with recovery rates ranging from 95.2% to 99.0% for the primary anemometers and 98.2% for the primary wind vane.

The measured data were adjusted to long-term through correlation with Environment Canada's Lourdes De Blanc Sablon A station, located 30 km away from the project area. The long-term adjustment method was applied since it was considered to be the best method for producing a representative dataset for the expected life of the project.

6.3 Wind Resource

The annual average wind speed at the met mast is a result of the measurements and the long-term adjustment. These wind speeds are summarised in the table below for top anemometer and hub height.

Table 6-1: Estimated Long-term Wind Speeds

Mast (Measurement Height)	Estimated Long-term Wind Speed at Measurement Height (m/s)	Estimated Long-term Wind Speed at Hub Height at 40 m (m/s)
2604 (35 m)	8.0	8.2

The long-term dataset at the met mast was used to build the wind flow across the project area.

The complexity of the terrain is considered moderate and its effect on the modelled wind is not considered problematic.

6.4 Forecasted Energy Production

The preliminary turbine selection analysis specified one suitable turbine model: EWT900. This models was proven to be best in class for cold and icy environments and suitable for wind-diesel generation in remote community.

The main results of the energy production modeling are summarised in the table below.

Table 6-2: Forecasted Annual Energy Production

Item	Layout 1 - EWT900
WTG Rated Power (kW)	900
Number of Wind Turbines	4
Wind Farm Capacity (kW)	3600
Annual Net Energy Production (MWh/yr)	**11,651**
Net Capacity Factor (P50) (%)	**36.9**

There remains some uncertainty regarding loss estimates, which should be reassessed as more information becomes available, particularly in relation to warranty contracts and maintenance schedules. Note that the Annual Net Energy Production represents the total forecasted energy production by the wind turbines. The effective energy production used to displace fuel will be a bit lower and vary depending on the chosen layout scenario (type and number of wind turbines), timewise power load and wind resource.

6.5 Recommendation

It should be noted that a number of additional studies and more detailed analysis will be required to refine and validate the turbine selected, the turbine position, the energy and losses.

The integration optimization report will show which turbine model is considered optimal for the L'Anse au Loup site based on energy cost, control capabilities and logistics and provide recommendations for further analysis and studies prior to implementation.

Safety • Quality • Sustainability • Innovation

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[1] International Energy Agency Programme, *Recommended practices for wind turbine testing and evaluation – Task 11: Wind Speed Measurement and Use of Cup Anemometer*, 1999

[2] National Renewable Energy Laboratory, *Wind Resource Assessment Handbook*, 1999

[3] International Electrotechnical Commission, *Wind Turbines - Part 1: Design Requirements*, IEC 61400-1, Ed. 3, 2005-08.

[4] International Electrotechnical Commission, *Wind Turbines - Part 12-1: Power performance measurements of electricity producing wind turbines*, IEC 61400-12-1, Ed. 1, 2005.

[5] A Practical Guide to Developing a Wind Project, *Wind Resource Assessment*, 2011

Appendix A

Views at Mast Site

View Facing North

View Facing East

View Facing South

View Facing West

Figure – A1: Views from Base of Mast 2604

Appendix B

Wind Turbine Data

EWT DW52-900

The power curve and the thrust curve were provided to Hatch by Emergya Wind Technologies.

Table – B1: EWT Wind Turbine Performance Curves

Rotor Diameter: 51.5 m	Hub Height: 40.0 m	Air Density: 1.225 kg.m^{-3}	Turbulence Intensity: N/A
Wind Speed at Hub Height (m/s)	**Electrical Power (kW)**	**Wind Speed at Hub Height (m/s)**	**Thrust Coefficients**
0	0	0	0.000
1	0	1	0.000
2	0	2	0.000
3	7	3	0.866
4	30	4	0.828
5	69	5	0.776
6	124	6	0.776
7	201	7	0.776
8	308	8	0.753
9	439	9	0.722
10	559	10	0.692
11	698	11	0.613
12	797	12	0.516
13	859	13	0.441
14	900	14	0.368
15	900	15	0.296
16	900	16	0.241
17	900	17	0.199
18	900	18	0.168
19	900	19	0.143
20	900	20	0.124
21	900	21	0.109
22	900	22	0.096
23	900	23	0.085
24	900	24	0.075
25	900	25	0.067

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Specification

DIRECTWIND 52/54*900 Technical Specification

Revision	Date	Author	Approved	Description of changes
02	02-03-12	MB	TY	Format, minor text, blades, options
01	28-11-11	LE	TY	Corrections and drawings
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-	-	-	-	-
-	-	-	-	-
-	-	-	-	-

Emergya Wind Technologies BV
Building 'Le Soleil' - Computerweg 1 - 3821 AA Amersfoort - The Netherlands
T +31 (0)33 454 0520 - F +31 (0)33 456 3092 - www.ewtinternational.com

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1 Introduction

This document provides a technical overview of the *DIRECTWIND* 52/54*900 Wind Turbine designed for the IEC class II/III application. It is to be read in conjunction with document S-1000921 “Directwind 52/54*900 Electrical Specification”.

2 Technical Description

The *DIRECTWIND* 52/54*900 is a direct-drive, variable speed, pitch regulated, horizontal axis, three-bladed upwind rotor wind turbine.

The gearless direct-driven synchronous generator operates at variable speed. This is made possible by an actively controlled AC-DC-AC IGBT power converter connected to the grid. Benefits of this design are low maintenance, constant power output at wind speed above rated, and relatively low structural loads compared to constant-speed stall-controlled or constant-speed pitch-controlled wind turbines.

The generator is fully integrated into the structural design of the turbine, which allows for a very compact nacelle design. The drive-train makes use of only one main bearing, whereas classic designs have separately supported main shaft, gearbox and generator. All dynamically loaded interfaces from the blades to the foundation are sturdy flange connections with machined surfaces, and high tensile steel pre-stressed bolt connections are used.

2.1 Operation and safety system

The turbine operates automatically under all wind conditions and is controlled by an industrial PLC (Programmable Logic Controller). The cut-in wind speed is approximately 3m/s. When the rotational speed reaches the cut-in threshold, the power converter begins to deliver power to the grid.

The power converter controls the generator power output and is programmed with a power set-point versus rotor speed curve. Below rated wind speed the power output is controlled to optimise rotor speed versus aerodynamic performance (optimum λ-control). Above rated wind speed the power output is kept constant at rated value by PD-controlled active blade pitching.

The dynamic responses of the drive train and power controller are optimised for high yield and negligible electrical power fluctuations. The variable speed rotor acts as a flywheel, absorbing fluctuating aerodynamic power input. The turbine controllers are located in the rotor hub and the tower base (with remote IO in the nacelle) and carry out all control functions and safety condition monitoring. In the case of a fault, or extreme weather conditions, the turbine is stopped by feathering of the blades to vane position (blades swivelled to 90^0 with respect to rotor's rotational plane). In case of power loss, an independent battery backup system in each blade ensures the blades are feathered.

In the case of less serious faults which have been resolved, or when extreme weather conditions have passed, the turbine restarts automatically to minimise downtime.

2.2 Generator

The multiple-pole, direct-drive generator is directly mounted to the hub. The stator is located in the non-moving outer ring and the wound pole, separately excited rotor rotates on the inner ring.

The generator is designed such that all aerodynamic forces are directly transferred to the nacelle construction without interfering with the generator-induced loads.

2.3 Power Converter

The power converter is an AC-DC-AC IGBT active switching converter. It controls the generator to operate in its optimum range, and maintains power quality to the grid. The inverter can produce unity power factor ($\cos\Phi=1$) to the grid under all load conditions. Power factor is also controllable within limits.

2.4 Rotor

The rotor is a three bladed construction, mounted up-wind of the tower. Rotational speed is regulated by active blade adjustment towards vane position. Blade pitch is adjusted using an electric servomotor on each of the blades.

Each blade has a complete, fully independent pitch system that is designed to be fail-safe. This construction negates the need for a mechanical rotor brake. The pitch system is the primary method of controlling the aerodynamic power input to the turbine.

At below rated wind speed the blade pitch setting is constant at optimum aerodynamic efficiency. At above rated wind speed the fast-acting control system keeps the average aerodynamic power at the rated level by keeping the rotor speed close to nominal, even in gusty winds.

The rigid rotor hub is a nodular cast iron structure mounted on the main bearing. Each rotor blade is connected to the hub using a pre-stressed ball bearing. It is sufficiently large to provide a comfortable working environment for two service technicians during maintenance of the pitch system, the three pitch bearings and the blade root from inside the structure.

2.5 Rotor blade set

The rotor blades are made of fibreglass-reinforced epoxy. The aerodynamic design represents state-of-the-art technology and is based on a pitch-regulated concept. No extenders are used and the aerodynamic design is optimal for this rotor diameter.

2.6 Main bearing

The large-diameter main bearing is a specially designed three row cylindrical roller bearing. The inner non-rotating ring is mounted to the generator stator. The outer rotating ring is mounted between the hub and generator rotor. The bearing takes axial and radial loads as well as bending moments. Entrance to the hub is through the inner-bearing ring. The bearing is greased by a fully automatic lubrication system controlled by the turbine PLC.

2.7 Nacelle

The nacelle is a compact welded construction which houses the yaw mechanism, a service hoist and a control cabinet. Both the generator and the tower are flanged to the nacelle. The geometry of the construction assures an ideal transfer of loads to the tower and, with the absence of a shaft and gearbox, results in a simple design ensuring easy personnel access.

2.8 Yaw system

The yaw bearing is an internally geared ring with a pre-stressed four point contact ball bearing. Electric planetary gear motors yaw the nacelle. The yaw brake is passive and is based on the friction of brake pads sitting directly on the bearing ring, keeping the yaw system rigid under most loading conditions.

2.9 Tower

The nacelle assembly is supported on a tubular steel tower, fully protected against corrosion. The tower allows access to the nacelle via a secure hinged access door at its base. The tower is fitted with an internal ladder with safety wire and optional climb assistance, rest platforms and lighting. Standard hub heights are 35, 40, 50 and 75 metres.

2.10 Anchor

The turbine is supported by a concrete foundation. The connection to this foundation is provided by means of a cast-in tube or rod anchor.

2.11 Control System

2.11.1 Bachmann PLC

The M1 controller perfectly combines the openness of a PC-based controller with the reliability of industrial hardware platforms. Designed to withstand the toughest ambient conditions it guarantees error-free use over long periods of time.

A modern system architecture designed for consistent network-capability permits the easy integration of the M1 into the environment of the controller and system peripherals. Real-time ethernet permits the real-time networking of the controllers, and the support of all standard Fieldbus systems permits the connection of standard external components.

2.11.2 DMS

DIRECTWIND Monitoring System – EWT's proprietary HMI featuring local monitoring and control at the turbine, integrated into a remote-access SCADA. DMS offers individual turbine control and total park monitoring and data logging from your Wind Turbine, Wind Park or internet access point.

2.12 Earthing and lightning protection

The complete earthing system of the wind turbine incorporates:

1. Protective earthing:
   A PE connection ensures that all exposed conductive surfaces are at the same electrical potential as the surface of the Earth, to avoid the risk of electrical shock if a person touches a device in which an insulation fault has occurred. It ensures that in the case of an insulation fault (a "short circuit"), a very high current flows, which will trigger an over-current protection device (fuse, circuit breaker) that disconnects the power supply.

2. Functional earthing:
   Earthing system to minimize and/or remove the source of electrical interference that can adversely affect operation of sensitive electrical and control equipment.

   A functional earth connection serves a purpose other than providing protection against electrical shock. In contrast to a protective earth connection, the functional earth connection may carry electric current during the normal operation of the turbine.

3. Lightning protection:
   To provide predictable conductive path for the over-currents in case of a lightning strike and electromagnetic induction caused by lightning strike and to minimize and/or remove dangerous situations for humans and sensitive electrical equipment.

Since the mechanical construction is made of metal (steel), all earthing systems are combined.

2.13 Options

The following options are available:

- Cold climate operation (rated for operation down to -40°C)
- Ice detection and/or prevention system
- Aviation lights
- Shadow flicker prevention
- Low Voltage Ride-through (LVRT)
- Service lift (75m tower only)
- G59 protection relay

3 Technical Data

Where data are separated by "/" this refers to the respective rotor diameter (52 / 54 m).

3.1 Wind and Site Data

Wind class	II / III according to IEC 61400 – 1
Max 50-year extreme	59.5 / 52.5 m/s
Turbulence class	A (I_{15} = 0.16)
Maximum flow inclination (terrain slope)	8°
Max ann. mean wind speed at hub height	8.5 / 7.5 m/s
Nominal air density	1.225 kg/m³

3.2 Operating Temperature

	Standard	Cold Climate
Min ambient operating	-20°C	-40°C
Max ambient operating	+40°C	+40°C

3.3 Cooling

Generator cooling	Air cooled
Converter cooling	Water or air cooled (configuration-dependent)

3.4 Operational Data

Cut in wind speed	3 m/s
Cut out wind speed	25 m/s
Rated wind speed	14 / 13.5 m/s
Rated rotor speed	26 rpm
Rotor speed range	12 to 33 rpm
Power output	900kW
Power factor	1.0 (adjustable 0.95 lagging to 0.95 leading) Measured at LV terminals

3.5 Rotor

Diameter	52 / 54 m
Type	3-Bladed, horizontal axis
Position	Up-wind
Swept area	2,083 / 2,290 m²
Power regulation	Pitch control; Rotor field excitation
Rotor tilt angle	5°

3.6 Blade Set

Type	PMC 24.5 / 25.8
Blade length	24.5 / 25.8 m
Chord at 22.0 m	0.879 m (90% of 24.5m blade radius)
Chord at 23.5 m	0.723 m (90% of 25.8m blade radius)
Chord Max at 5.5 m	2.402 m
Aerodynamic profile	DU 91, DU 98 and NACA 64618
Material	Glass reinforced epoxy
Leading edge protection	PU coating
Surface colour	Light grey RAL 7035
Twist Distribution	11.5^0 from root to 5.5m then decreases linearly to 0.29^0, then non-linearly to 0^0

3.7 Transmission System

Type	Direct drive
Couplings	Flange connections only

3.8 Controller

Type	Bachmann PLC
Remote monitoring	DIRECTWIND Monitoring System, proprietary SCADA

3.9 Pitch Control and Safety System

Type	Independent blade pitch control
Activation	Variable speed DC motor drive
Safety	Redundant electrical backup

3.10 Yaw System

Type	Active
Yaw bearing	4 point ball bearing
Yaw drive	3 x constant speed electric geared motors
Yaw brake	Passive friction brake

3.11 Tower

Type	Tapered tubular steel tower
Hub height options	HH = 35, 40, 50, 75 m
Surface colour	Interior: White RAL 9001, Exterior: Light grey RAL 7035

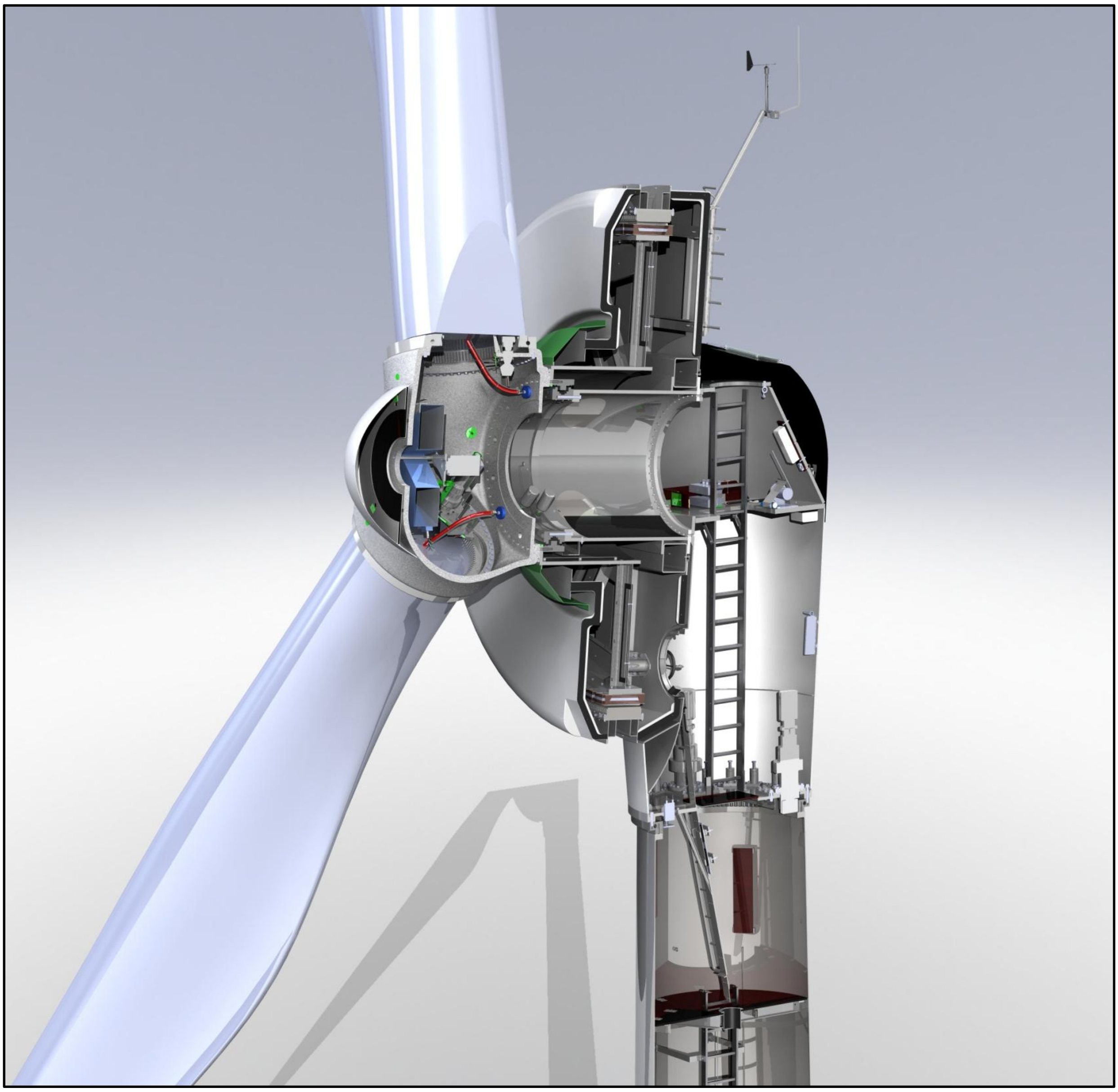
3.12 Mass Data

Hub	9,303 kg
Blade – each	1,919 / 1,931 kg
Rotor assembly	15,060 / 15,096 kg
Generator	30,000 kg
Nacelle assembly	10,000 kg
Tower HH35	28,300 kg
Tower HH40	34,000 kg
Tower HH50	46,000 kg
Tower HH75	86,500 kg

3.13 Service Brake

Type	Maintenance brake
Position	At hub flange
Calipers	Hydraulic 1-piece

APPENDIX 1: 3D image of main turbine components



Appendix F: Hybrid system modelling and optimisation report - Nain

Project Report

November 9, 2015

Coastal Labrador Wind Monitoring Program

Nain Hybrid System Modeling and Optimization

Distribution

Trevor Andrew – NLH
Asim Haldar – NLH
Bob Moulton – NLH
Timothy Manning – NLH
Terry Gardiner – NLH
Louis Auger – Hatch
Dany Awad – Hatch
Ève-Line Brouillard - Hatch

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1. Introduction, Objectives and Scope of Work

As part of the project titled, Coastal Labrador Wind Monitoring Program, Newfoundland and Labrador Hydro (NLH) mandated Hatch to complete a wind monitoring campaign to determine the feasibility of adding Wind Turbine Generators (WTG) to Labrador isolated communities of Nain, Hopedale, Makkovik, Cartwright and L'Anse au Loup. This report presents the methodology and results related to Nain.

The wind monitoring periods are listed in the table below and additional information on the wind monitoring campaigns can be found in the respective WRA reports completed for each community.

	Date of first data recorded	Date of last data recorded
Nain (mast 2601)	30 October 2013	19 July 2015
Hopedale (mast 2602)	27 October 2013	19 July 2015
Makkovik (mast 2603)	25 October 2013	19 July 2015
Cartwright (mast 2605)	5 November 2013	13 July 2015
L'Anse au Loup (mast 2604)	5 October 2013	27 April 2015

Table 1 : Sites and Monitoring Periods

The specific objectives of the mandate were to provide the potential wind turbine capacity that can be installed on these 5 communities, the potential wind penetration and the associated cost breakdown for development, construction and operations (CapEx and OpEx).

2. Overview of Existing Diesel Grid on Site

Nain is one of the largest communities in Northern Labrador and consequently has a large electrical demand compared to neighbouring communities. The electrical equipment on site as well as electrical load and future forecast are defined below, based on the information provided by NLH.

2.1 Installed Power Generation Equipment

The power grid operated by NLH at Nain currently relies on three (3) diesel generators (Gensets). A fourth unit is scheduled to be installed onsite in 2015. This configuration is common for isolated communities where it would be too costly to interconnect to the main provincial grid. The gensets currently on site include the following units:

Unit Number	Unit kW	Brand	Model	RPMs	Purchase Year
G1)574	865	Detroit Diesel	Se2000R1637K36	1800	2001
(G3)576	865	Detroit Diesel	Se2000R1637K36	1800	2001
(G2)2085	1275	CAT	D-3512B	1800	2009
(G4)TBD	750	MTU	12V4000G73	1200	Planned 2015

Table 2 : Diesel Gensets on Site

2.2 Generator Control Scheme

The gensets on site are managed by an automated control scheme. NLH explained that the control logic aims to minimize the number and size of the gensets running at any given time while also insuring sufficient spinning reserve to meet increases in load. To do so, whenever the unit running is operating at less than 75% load ratio, the system switches to a smaller unit, if available. Whenever the unit running is loaded at more than 85%, the system switches to a larger unit, if available, or starts a second generator to share the load.

The minimum load ratio for all gensets operated by NLH is 30%.

These control parameters are important for the modeling part of the process and will be discussed later.

2.3 Electric Load

The electric load at Nain varies significantly between winter and summer months. NLH provided historical monthly average hourly electrical load. This data is shown in the table below:

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Nain	1,347	1,125	985	912	856	679	632	725	689	924	898	1,226

Table 3 : Average Load (kW)

Furthermore, a monitoring system was recently installed by NLH to record 15 minute electrical production from each genset. The data recorded by this system, which covers the period of December 2014 to April 2015, was made available for inclusion in the model. This dataset provided the basis of calculation for the production of a daily hourly load profile, an essential component of the modeling exercise.

It should be noted that the 15 minute dataset provided shows that more genset hours are required to produce the energy for the site compared to what is predicted by the modelling software.

2.4 Forecasted Load and Fuel Price

NLH provided information showing anticipated growth of peak hourly power demand and total yearly energy for the years 2015 to 2033 for Nain. The expected average fuel cost for each year was also supplied for the same period. The table below summarizes this information.

Nain	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033
Gross Peak (kW)	1,981	2,026	2,066	2,107	2,148	2,165	2,207	2,250	2,294	2,339	2,385	2,426	2,467	2,509	2,552	2,596	2,638	2,681	2,724
Net Peak (kW)	1,929	1,973	2,014	2,054	2,095	2,113	2,155	2,198	2,242	2,287	2,333	2,374	2,415	2,457	2,500	2,544	2,586	2,629	2,672
Gross Energy (MWh)	9,301	9,516	9,711	9,908	10,104	10,306	10,513	10,723	10,937	11,156	11,379	11,578	11,781	11,987	12,197	12,410	12,615	12,823	13,035
Net Energy (MWh)	9,019	9,228	9,418	9,608	9,799	9,995	10,195	10,398	10,606	10,819	11,035	11,228	11,424	11,624	11,828	12,035	12,233	12,435	12,640
Fuel Price forecast	$0.96	$1.02	$1.02	$1.06	$1.09	$1.09	$1.13	$1.19	$1.24	$1.31	$1.39	$1.43	$1.47	$1.50	$1.54	$1.58	$1.62	$1.67	$1.71

Table 4 : Forecasted load and fuel price growth (2015-2033)

The forecasted load growth and fuel price increase were important components in the evaluation of the various available system configurations as the objective was to find the most desirable system over the life of the project.

3. Design methodology

3.1 Software Used

The electrical system and integration of the wind turbines was modelled and simulated using HOMER (Hybrid Optimization of Multiple Electric Renewables). This software is specifically used to model and optimize the configuration of micro-grid systems composed of multiple components, which can include wind turbine generators, photovoltaic solar panels, hydroelectric generators, batteries as well as generators running on various types of fuel. Using inputs comprising electric load profile, electrical architecture of the system (DC vs AC, etc.), renewable resources as well as costs for the purchase, operation and replacement of each component, HOMER can investigate multiple configurations and produce insight as to how to minimize the Levelized Cost of Energy (LCOE) or fuel used by the system. In the context of the current assignment, the outputs of the software were integrated in MS Excel spreadsheets to include electrical load and fuel cost variations over time with the aim of selecting the most efficient solution over the life of the project.

3.2 Model Building

NLH provided valuable information related to the historical operating performance of the existing system. The data provided included operations and maintenance (O&M) costs and overhaul costs, as well as data linking electrical production and fuel consumption. Each genset model was created in HOMER to accurately reflect these parameters, as well as the specific fuel curve provided by NLH.

The average monthly electrical load provided by NLH was used as the basis for the load profile included in the model. The 15 minute genset production dataset, covering a 5 month period, was used to establish a daily electric production profile. The assumption was made that the electric production at any given time was equal to the electric demand, so the daily load profile would be the same as the daily production profile. This daily load profile proved to be similar in shape for all 5 months of data provided, with differing magnitudes across months. As such, the assumption was made that the typical daily load profile shape would be the same for all 12 months but that it would be scaled to reflect the monthly averages provided by NLH. This daily load profile for each month was integrated as the electric load for the project. HOMER uses the base hourly profile and introduces hour to hour and day to day random variations based on parameters defined by the user. The result is a random time series for the load that has a pattern similar to the actual load.

At this point an iteration of the model was run in a configuration representing the equipment present on site to verify that HOMER would yield results similar to the numbers provided by NLH. The energy cost, generator run hours and quantity of fuel burned per year all came to within 5% of the numbers provided by NLH for project year 1. This provided validation that the model could be relied upon to accurately represent the system.

A preliminary turbine selection for the Nain project was completed as part of the Wind Resource assessment phase and two WTGs models from two different OEMs were selected; additional information on the turbine selection methodology is available in the WRA report. These turbines are the Northern Power Systems 100kW arctic version (NPS100) and the Emergya Wind Technologies 900kW (EWT900). Both WTGs were modeled in HOMER based on manufacturer provided specifications. The long term wind resource calculated in the wind resource assessment campaign was integrated in the model and the energy production predicted by the software WindFarmer for each turbine model was compared with the energy calculated by HOMER. WindFarmer is routinely used to optimize wind farm layouts with regard to energy, topography and restrictions and to estimate the energy production. WindFarmer outputs are considered more accurate than HOMER for this aspect. Following some minor model adjustments, the comparison showed that the HOMER results were similar to the WindFarmer results within a few percent, confirming that the simulation used realistic wind energy production numbers.

The following assumptions were made during the optimization process and in the simulation phase:

- The daily load profile was derived from time series and historical values provided by NLH
- Fuel costs and load growth were based on information provided by NLH, as presented in Section 2.4
- An inflation rate of 2.21% and average NLH long term marginal cost of debt (rounded) of 6.48% were used, according to historical values specified by NLH
- Construction costs have been defined based on information from manufacturers and historical values from past projects

3.3 System Sizing and Optimization

The sizing and optimisation of the proposed wind project for Nain was determined through an iterative process. HOMER simulations were run using varying numbers of each WTG model selected in the previous phase. The objective of the iterations was to determine the number of WTGs for each model that would result in the lowest calculated cost of energy (COE).

The outputs from Homer were integrated in Excel spreadsheets to evaluate the impact of increasing fuel costs, electrical demand, inflation and cost of borrowed capital. Some key metrics were identified to compare the various configurations and determine the most economically viable scenarios. The results are presented in the following section.

4. Results

4.1 Proposed Configuration

Based on the modeling performed in HOMER, the optimal number of turbines for integration in the Nain system is 12 when considering the NPS100 and 2 when considering the EWT900. Since the turbines are very different in scale, a qualitative comparison between the models is presented at the end of the current section. The table below shows a summary of the results for integration of various numbers of each WTG model.

	Fuel saved vs base case	Yearly Fuel Savings	Wind Penetration	WTG energy over 20 yrs (kWh)	Excess energy over 20 yrs (kWh)	Cost of Energy ($/kWh)
No WTG	0%	$0	0%	0	0	$0.321
10 NPS100	29.2%	$1,085,126	30.1%	67,582,180	3,260,801	$0.312
12 NPS100	33.8%	$1,256,596	34.8%	81,098,760	6,719,029	$0.310
14 NPS100	37.6%	$1,403,601	38.9%	94,615,200	11,620,161	$0.311
1 EWT900	26.9%	$785,467	27.7%	61,517,240	2,374,253	$0.283
2 EWT900	43.2%	$1,461,339	44.7%	123,034,480	27,592,535	$0.263
3 EWT900	50.1%	$1,757,036	52.0%	184,552,320	73,430,369	$0.272

Table 5 : Summary of Results

The estimated energy production of each proposed configuration accounts for the possible losses in a wind farm, such as wake, aerodynamic, electrical, operational and power curve losses. The figures of availability should be defined with more accuracy at the detailed turbine selection stage, based on statistics for the turbine selected and after confirmation of the O & M strategy and review of the draft O&M contract if applicable. Based on preliminary manufacturer's discussions, other factors that will need to be considered for availability include the benefit of having a greater number of turbine units due to potential difficulties to execute repairs in the winter months. This will need to be analyzed as part of the turbine selection process.

As noted in Sections 4.2 and 4.3, the cost of energy does not include all applicable costs. As such, this preliminary cost of energy provides an indicator that, at this point, the project is viable and warrants further study. Additional costs not reflected include mechanical and electrical stability studies, system integration costs, control and communications system costs, as well as detailed logistic studies, plant detailed design and optimization.

4.2 Construction Costs

The total estimated cost of building a wind farm at Nain include development, turbine, construction and project management. Project contingency was also included, at 5% for WTG components and 10% for construction costs. Additional integration and pre-development costs include logistics study, integration study, electrical and mechanical stability studies have not been included. System integration costs have also been left out of the equation, as well as any associated integration and communication equipment costs since this scope were

not included in the present project. All of the aforementioned studies would need to be completed to fully assess the viability of the project. The following table shows a summary of the included project costs for various iterations:

	NPS 100			EWT 900		
Number of units	**10**	**12**	**14**	**1**	**2**	**3**
Development costs	$375,000	$375,000	$375,000	$375,000	$375,000	$375,000
Turbine costs	$4,400,000	$5,280,000	$6,160,000	$2,375,000	$4,750,000	$7,125,000
Construction costs	$3,629,757	$3,926,409	$4,223,060	$2,363,800	$3,291,300	$4,102,200
Project management	$840,476	$958,141	$1,075,806	$511,380	$841,630	$1,160,220
Contingency	$704,523	$789,955	$875,387	$443,768	$688,293	$919,992
Total project CapEx:	**$9,949,756**	**$11,329,505**	**$12,709,253**	**$6,068,948**	**$9,946,223**	**$13,682,412**
CapEx per installed MW:	$9,949,756	$9,441,254	$9,078,038	$6,743,276	$5,525,679	$5,067,560

Table 6 : Summary of Construction Costs

For the detailed construction costs see Annex 1.

4.3 Further Study Required – System Integration

The installation of WTGs on the grid at Nain will require further electrical and mechanical studies, which are not part of the current scope of work and should be performed at a later stage to fully assess the project viability. The results of these studies will determine whether additional control and communication equipment needs to be added to the system. It should be noted that since it is not currently known if any additional equipment will be required, no cost was included for such components in any of the simulations at this stage. The energy costs presented in the following section include no allocation for additional control and communication equipment.

4.4 Penetration and Energy Cost

The cost of energy for each option is calculated based on the total cost of producing the required quantity of energy during the life of the project and the total amount of energy produced. Costs are based on the cost of borrowed capital for CapEx, increasing fuel costs and energy demand as well as anticipated discount rate (inflation) over the duration of the project. All costs presented in this report are based on the average long term marginal cost of debt of 6.48% provided by NLH. However this historical value may not be representative of future interest rates and a different value could have a significant impact on the cost of energy for configurations using WTGs because of the large investment required. For information purposes, the resulting cost of energy associated with an interest rate of 4.5% was included in the Figure 1 : Average Cost of Energy.

The level of penetration of wind energy in the energy pool at Nain is proportional to the number of WTG installed on site. This value represents the total amount of power produced by wind turbines over the project life divided by the total amount of power used.

The results for average cost of energy and wind penetration over the expected project life of 20 years are shown in the figure below. From this figure, it can clearly be seen that there are

configurations using either WTG model that produce a COE lower than the base case. However, the EWT900 results in a much lower overall cost of energy and a much higher wind penetration level than the NPS100. The design methodology leading to these results was provided in Section 3.

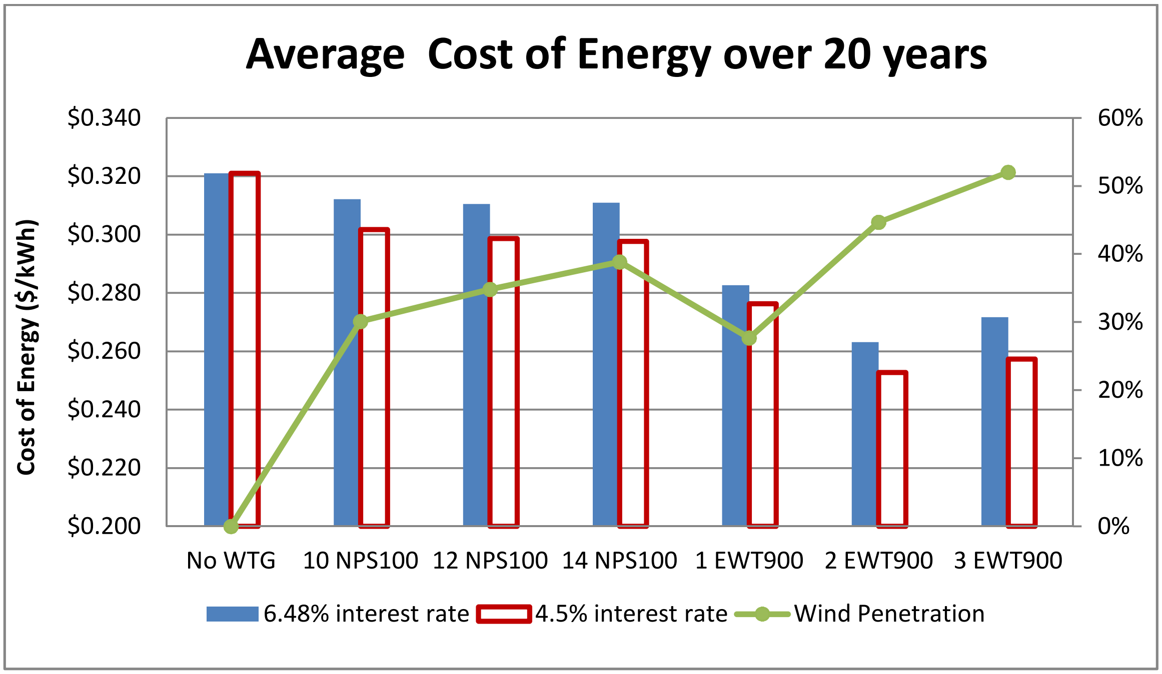

Figure 1 : Average Cost of Energy

4.5 Evolution of Cost of Energy

Figure 2 : Evolution of Cost of Energy shows the evolution of the non-discounted cost of power over the 20 years of the project life. It illustrates that the inclusion of more WTGs or larger WTGs in the energy mix reduces the impact of rising fuel costs on the average cost of energy over the project life. The graph also indicates that scenarios with the EWT900 turbine result in much lower energy costs. Scenarios with the NPS100 also result in a lower energy cost than the base case, but the cost is significantly higher than the results with the EWT900.

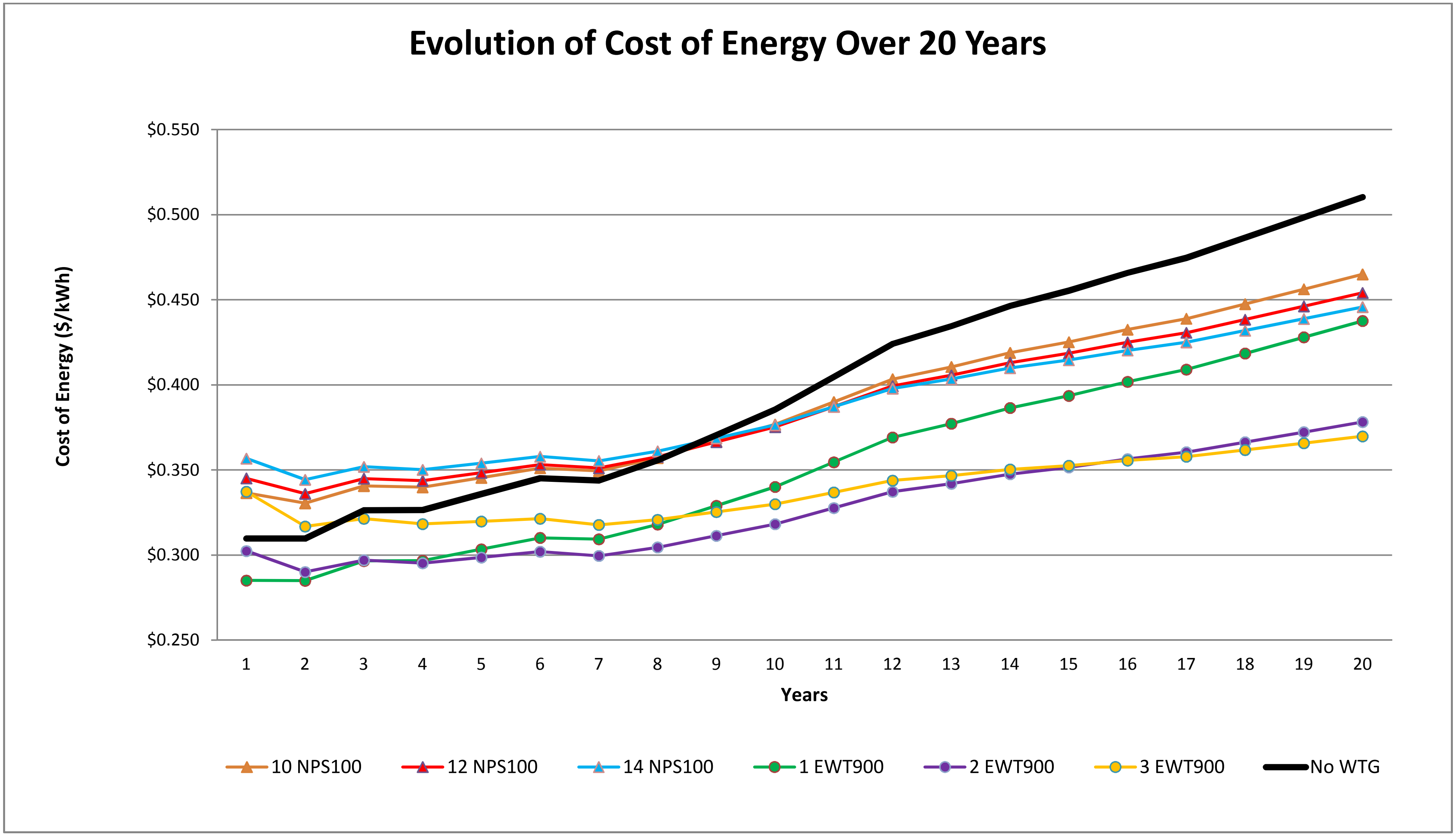

Figure 2 : Evolution of Cost of Energy

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4.6 Fuel Costs and Excess Wind Energy

The average yearly fuel costs provide a good indication of the system reliance on fossil fuels for operation. The greater the installed wind capacity, the lower the annual fuel costs. However because of the magnitude and variability of electrical load on site, above a certain quantity of turbines, not all the energy produced by the turbines can be used by the system, causing the WTG to be less efficient.

The following figure shows the average yearly fuel costs for each configuration as well as the associated percentage fuel saved. The percentage of wasted WTG energy is also shown.

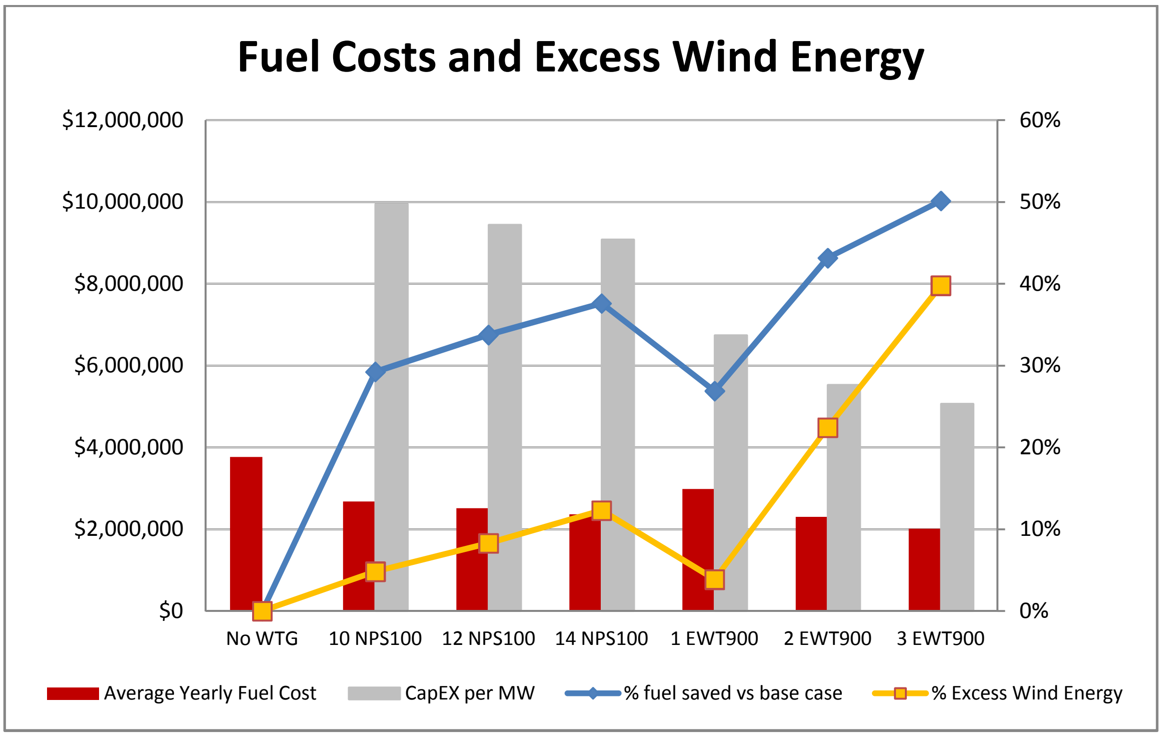

Figure 3 : Fuel Costs and Excess Wind Energy

4.7 Avoided Greenhouse Gas Emissions

The addition of renewable energy to the Cartwright electrical grid would have an impact on the amount of Greenhouse Gas (GHG) emissions resulting from energy production. NLH specified that it uses a value of 2.791 kg of CO_2 for each liter of diesel burned in the gensets it operates. Based on this number, Hatch calculated that the amount of avoided GHG emissions for each project configuration is as follows:

Case	Avoided Emissions of CO_2 (tonnes) over 1 Year	Avoided Emissions of CO_2 (tonnes) over 20 years
No WTG	0	0
10 NPS100	2,318	46,359
12 NPS100	2,676	53,525
14 NPS100	2,981	59,623
1 EWT900	2,133	42,659
2 EWT900	3,421	68,421
3 EWT900	3,974	79,485

Table 7 : Avoided Emissions of CO_2

Note: As of 2010, total Newfoundland and Labrador Green house gas emissions were 8.9 million tonnes per year, so avoided emissions by the installation of 2 EWT900 WTG at Nain would be equal to 0.038 % of total Provincial emissions.

4.8 Qualitative Comparison of WTG Models

The results presented in Section 4.1 clearly highlight the difference in wind penetration and energy cost between the two turbines being considered. The NPS100 is a small wind turbine that is easier to deploy yet has limited control capabilities, while the EWT900 is a full-size turbine with a large rotor diameter and the full control package associated with a utility scale turbine. Both turbines have an excellent track record in arctic conditions, making both potential candidates for the application. On the economic aspect, though the cost estimates will need to be validated in the next phase of the project, the cost per installed kW is much lower for the larger turbine which is generally common within the wind industry. Consequently, the energy produced comes at a lower price for the EWT900 than the NPS100. On the electrical side, the EWT is oversized for the application and produces much more energy than the NPS. Accordingly, the amount of excess energy by the EWT WTG is far above the NPS model, however the overall cost of useful energy remains lower for the EWT. The excess energy is expected to be easier to manage on the EWT as well, since it has active curtailment and derating management capabilities. From an environmental perspective, the EWT allows for more avoided emissions than the NPS. The practical O&M aspect also favors the EWT, as the manufacturer offers O&M options through long term contracts and, under certain circumstances, will even offer an availability warranty.

The size of the EWT900 makes for a more complex deployment, construction and installation. The logistical capabilities, including the remoteness, of the Nain port and community are not well documented and may make the delivery, unloading, transport and installation of the EWT turbine much more expensive than budgeted at present. This could be a fatal flaw associated with the EWT900 WTG. A full logistic analysis is strongly recommended to confirm whether the installation of the EWT900 WTG is feasible. It needs to be noted that turbine models between 100 KW to 900 KW are not commonly available from many OEMs especially for use in arctic conditions. A more detailed turbine selection process should be initiated in following phases of the project.

The table below shows a comparison between the two models with "X" indicating superiority in each category:

Category	NPS100	EWT900
Track Record	X	X
Turbine Cost		X
Energy Poduction		X
Control Capabilities		X
Avoided Emissions		X
O&M		X
Logistics	X	

Table 8 : WTG qualitative comparison

Figure 4 highlights the size differences between the NPS100 and the EWT900.

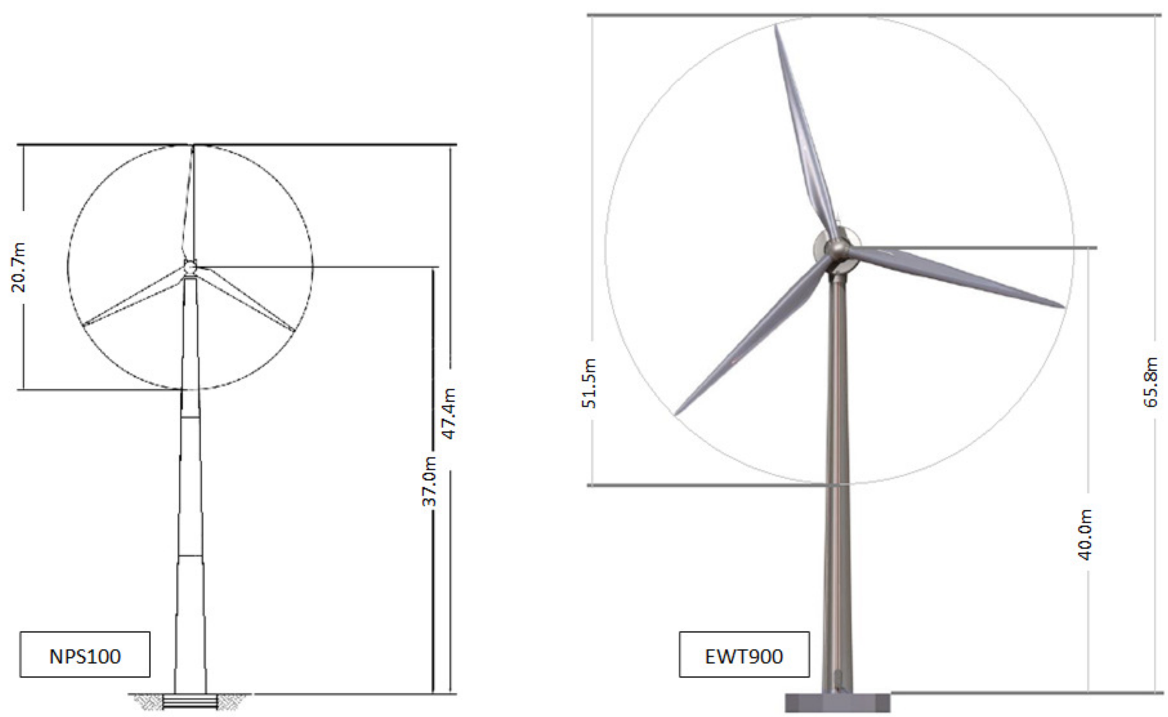

Figure 4 : Turbines Size

5. Conclusion and Recommendations

Based on the system modeling and preliminary economic analysis performed by Hatch, the optimal system design for Nain is the installation of two EWT900 WTGs. This result is based on the anticipated energy production of the existing gensets and the future wind turbines, according to the functional specifications of the local grid as provided by NLH. It should be noted that several components were excluded from this analysis, including the value of avoided GHG emissions, the level of community acceptance and government policy implications. It is recommended that NLH gather more information on these topics prior to moving forward with further assessments of project viability.

It is important to note that a detailed mechanical and electrical stability study was not performed at this stage. It is critical that such a study be performed in advance of the detailed design stage to determine the impacts of adding WTGs to the existing system, as well as the actual limitations of the current grid. Furthermore, a logistics analysis needs to be completed to determine whether the local capabilities allow for the installation of the EWT900 turbine.

ELB
Attachment(s)/Enclosure :
Annex 1 - Construction Costs.pdf
H340923-0000-05-124-0001_rev4.pdf (Nain Final Wind Resource Assessment Report)

Appendix G: Hybrid system modelling and optimisation report - Hopedale

Project Report

November 9, 2015

Coastal Labrador Wind Monitoring Program

Hopedale Hybrid System Modeling and Optimization

Distribution

Trevor Andrew – NLH
Asim Haldar – NLH
Bob Moulton – NLH
Timothy Manning – NLH
Terry Gardiner – NLH
Louis Auger – Hatch
Dany Awad – Hatch
Ève-Line Brouillard - Hatch

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1. Introduction, Objectives and Scope of Work

As part of the project titled, Coastal Labrador Wind Monitoring Program, Newfoundland and Labrador Hydro (NLH) mandated Hatch to complete a wind monitoring campaign to determine the feasibility of adding Wind Turbine Generators (WTG) to Labrador isolated communities of Nain, Hopedale, Makkovik, Cartwright and L'Anse au Loup. This report presents the methodology and results related to Hopedale.

The wind monitoring periods are listed in the table below and additional information on the wind monitoring campaigns can be found in the respective WRA reports completed for each community.

	Date of first data recorded	Date of last data recorded
Nain (mast 2601)	30 October 2013	19 July 2015
Hopedale (mast 2602)	27 October 2013	19 July 2015
Makkovik (mast 2603)	25 October 2013	19 July 2015
Cartwright (mast 2605)	5 November 2013	13 July 2015
L'Anse au Loup (mast 2604)	5 October 2013	27 April 2015

Table 1 : Sites and Monitoring Periods

The specific objectives of the mandate were to provide the potential wind turbine capacity that can be installed on these 5 communities, the potential wind penetration and the associated cost breakdown for development, construction and operations (CapEx and OpEx).

2. Overview of Existing Diesel Grid on Site

Hopedale is an average size community in Northern Labrador and consequently has a moderate electrical demand compared to neighbouring communities. The electrical equipment on site as well as electrical load and future forecast are defined below, based on the information provided by NLH.

2.1 Installed Power Generation Equipment

The power grid operated by NLH at Hopedale currently relies on four (4) diesel generators (Gensets). This configuration is common for isolated communities where it would be too costly to interconnect to the main provincial grid. The gensets currently on site include the following units:

Unit Number	Unit kW	Brand	Model	RPMs	Purchase Year
(G1)2074	569	CAT	3412C	1800	2005
(G2)2054	475	CAT	D-3508	1200	1999
(G3)2053	545	CAT	D-3412	1800	1998
(G4)925	925	MTU	12V4000G73	1200	2014

Table 2 : Diesel Gensets on Site

2.2 Generator Control Scheme

The gensets on site are managed by an automated control scheme. NLH explained that the control logic aims to minimize the number and size of the gensets running at any given time while also insuring sufficient spinning reserve to meet increases in load. To do so, whenever the unit running is operating at less than 75% load ratio, the system switches to a smaller unit, if available. Whenever the unit running is loaded at more than 85%, the system switches to a larger unit, if available, or starts a second generator to share the load.

The minimum load ratio for all gensets operated by NLH is 30%.

These control parameters are important for the modeling part of the process and will be discussed later.

2.3 Electric Load

The electric load at Hopedale varies significantly between winter and summer months. NLH provided the 2014 monthly average hourly electrical load. This data is shown in the table below:

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Hopedale	754	652	581	517	558	407	338	369	376	524	544	720

Table 3 : Average Load (kW)

Furthermore, a monitoring system was recently installed by NLH, in some communities, to record 15 minute electrical production from each genset. The data recorded by this system was made available for inclusion in the model. Unfortunately this information was not provided for Hopedale, either because the system has not been installed there, or the dataset was not available. Since the hourly average productions for each month is an essential component of the modeling exercise, Section 3.2 describes how it has been defined for Hopedale.

2.4 Forecasted Load and Fuel Price

NLH provided information showing anticipated growth of peak hourly power demand and total yearly energy for the years 2015 to 2033 for Hopedale. The expected average fuel cost for each year was also supplied for the same period. The table below summarizes this information.

Hopedale	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033
Gross Peak (kW)	1,294	1,315	1,359	1,379	1,421	1,474	1,518	1,563	1,603	1,643	1,684	1,726	1,769	1,808	1,848	1,888	1,930	1,968	2,008
Net Peak (kW)	1,215	1,237	1,281	1,301	1,342	1,395	1,439	1,484	1,524	1,564	1,605	1,647	1,690	1,729	1,769	1,809	1,851	1,889	1,929
Gross Energy (MWh)	5,944	6,040	6,239	6,330	6,517	6,713	6,914	7,122	7,300	7,482	7,669	7,861	8,058	8,235	8,416	8,601	8,790	8,966	9,146
Net Energy (MWh)	5,334	5,420	5,599	5,681	5,849	6,024	6,205	6,391	6,551	6,714	6,882	7,054	7,231	7,390	7,552	7,718	7,888	8,046	8,207
Fuel Price ($/L)	$0.98	$1.04	$1.04	$1.07	$1.11	$1.10	$1.15	$1.20	$1.26	$1.33	$1.41	$1.45	$1.49	$1.53	$1.56	$1.60	$1.64	$1.69	$1.74

Table 4 : Forecasted load and fuel price growth (2015-2033)

The forecasted load growth and fuel price increase were important components in the evaluation of the various available system configurations as the objective was to find the most desirable system over the life of the project.

3. Design methodology

3.1 Software Used

The electrical system and integration of the wind turbines was modelled and simulated using HOMER (Hybrid Optimization of Multiple Electric Renewables). This software is specifically used to model and optimize the configuration of micro-grid systems composed of multiple components, which can include wind turbine generators, photovoltaic solar panels, hydroelectric generators, batteries as well as generators running on various types of fuel. Using inputs comprising electric load profile, electrical architecture of the system (DC vs AC, etc.), renewable resources as well as costs for the purchase, operation and replacement of each component, HOMER can investigate multiple configurations and produce insight as to how to minimize the Levelized Cost of Energy (LCOE) or fuel used by the system. In the context of the current assignment, the outputs of the software were integrated in MS Excel spreadsheets to include electrical load and fuel cost variations over time with the aim of selecting the most efficient solution over the life of the project.

3.2 Model Building

NLH provided valuable information related to the historical operating performance of the existing system. The data provided included operations and maintenance (O&M) costs and overhaul costs, as well as data linking electrical production and fuel consumption. Each genset model was created in HOMER to accurately reflect these parameters, as well as the specific fuel curve provided by NLH.

The average monthly electrical load provided by NLH was used as the basis for the load profile included in the model. For the other communities, a 5 month of 15 minute electrical production has been provided and use to calculate the hourly average productions for each month. This information has not been provided for Hopedale, but based on the 2014 monthly average hourly production, Hopedale has a similar shape than Nain, thus the daily hourly load profile of Nain has been used as the basis of calculation for the average hourly production for each month at Hopedale. The assumption was made that the typical daily load profile shape would be the same for all 12 months but that it would be scaled to reflect the monthly averages provided by NLH for Hopedale. This daily load profile for each month was integrated as the electric load for the project. HOMER uses the base hourly profile and introduces hour to hour and day to day random variations based on parameters defined by the user. The result is a random time series for the load that has a pattern similar to the actual load.

At this point an iteration of the model was run in a configuration representing the equipment present on site to verify that HOMER would yield results similar to the numbers provided by NLH. The energy cost, generator run hours and quantity of fuel burned per year all came to within 5% of the numbers provided by NLH for project year 1. This provided validation that the model could be relied upon to accurately represent the system.

A preliminary turbine selection for the Hopedale project was completed as part of the Wind Resource assessment phase and two WTGs models from two different OEMs were selected; additional information on the turbine selection methodology is available in the WRA report. These turbines are the Northern Power Systems 100kW arctic version (NPS100) and the Emergya Wind Technologies 900kW (EWT900). Both WTGs were modeled in HOMER based on manufacturer provided specifications. The long term wind resource calculated in the wind resource assessment campaign was integrated in the model and the energy production predicted by the software WindFarmer for each turbine model was compared with the energy calculated by HOMER. WindFarmer is routinely used to optimize wind farm layouts with regard to energy, topography and restrictions and to estimate the energy production. WindFarmer outputs are considered more accurate than HOMER for this aspect. Following some minor model adjustments, the comparison showed that the HOMER results were similar to the WindFarmer results within a few percent, confirming that the simulation used realistic wind energy production numbers.

The following assumptions were made during the optimization process and in the simulation phase:

- The daily load profile was derived from time series and historical values provided by NLH
- Fuel costs and load growth were based on information provided by NLH, as presented in Section 2.4
- An inflation rate of 2.21% and average NLH long term marginal cost of debt (rounded) of 6.48% were used, according to historical values specified by NLH
- Construction costs have been defined based on information from manufacturers and historical values from past projects

3.3 System Sizing and Optimization

The sizing and optimisation of the proposed wind project for Hopedale was determined through an iterative process. HOMER simulations were run using varying numbers of each WTG model selected in the previous phase. The objective of the iterations was to determine the number of WTGs for each model that would result in the lowest calculated cost of energy (COE).

The outputs from Homer were integrated in Excel spreadsheets to evaluate the impact of increasing fuel costs, electrical demand, inflation and cost of borrowed capital. Some key metrics were identified to compare the various configurations and determine the most economically viable scenarios. The results are presented in the following section.

4. Results

4.1 Proposed Configuration

Based on the modeling performed in HOMER, the optimal number of turbines for integration in the Hopedale system is 8 when considering the NPS100 and 1 when considering the EWT900. Since the turbines are very different in scale, a qualitative comparison between the models is presented at the end of the current section. The table below shows a summary of the results for integration of various numbers of each WTG model.

	Fuel saved vs base case	Yearly Fuel Savings	Wind Penetration	WTG energy over 20 yrs (kWh)	Excess energy over 20 yrs (kWh)	Cost of Energy ($/kWh)
No WTG	0%	$0	0%	0	0	$0.327
6 NPS100	29.8%	$696,662	29.2%	41,446,900	2,838,768	$0.308
7 NPS100	32.9%	$773,230	32.9%	48,354,800	4,820,916	$0.308
8 NPS100	36.1%	$851,018	36.2%	55,262,720	7,325,970	$0.307
9 NPS100	39.0%	$798,480	39.2%	62,170,360	10,313,566	$0.308
1 EWT900	41.0%	$854,928	41.3%	67,983,500	13,264,799	$0.262
2 EWT900	53.9%	$1,203,635	54.8%	135,967,020	63,469,302	$0.270

Table 5 : Summary of Results

The estimated energy production of each proposed configuration accounts for the possible losses in a wind farm, such as wake, aerodynamic, electrical, operational and power curve losses. The figures of availability should be defined with more accuracy at the detailed turbine selection stage, based on statistics for the turbine selected and after confirmation of the O & M strategy and review of the draft O&M contract if applicable. Based on preliminary manufacturer's discussions, other factors that will need to be considered for availability include the benefit of having a greater number of turbine units due to potential difficulties to execute repairs in the winter months. This will need to be analyzed as part of the turbine selection process.

As noted in Sections 4.2 and 4.3, the cost of energy does not include all applicable costs. As such, this preliminary cost of energy provides an indicator that, at this point, the project is viable and warrants further study. Additional costs not reflected include mechanical and electrical stability studies, system integration costs, control and communications system costs, as well as detailed logistic studies, plant detailed design and optimization.

4.2 Construction Costs

The total estimated cost of building a wind farm at Hopedale includes development, turbine, construction and project management. Project contingency was also included, at 5% for WTG components and 10% for construction costs. Additional integration and pre-development costs include logistics study, integration study, electrical and mechanical stability studies have not been included. System integration costs have also been left out of the equation, as well as any associated integration and communication equipment costs since this scope were

not included in the present project. All of the aforementioned studies would need to be completed to fully assess the viability of the project. The following table shows a summary of the included project costs for various iterations:

	NPS 100				EWT 900	
Number of units	**6**	**7**	**8**	**9**	**1**	**2**
Development costs	$375,000	$375,000	$375,000	$375,000	$375,000	$375,000
Turbine costs	$2,640,000	$3,080,000	$3,520,000	$3,960,000	$2,375,000	$4,750,000
Construction costs	$1,491,504	$1,625,255	$1,759,006	$1,892,757	$1,605,900	$2,416,800
Project management	$450,650	$508,026	$565,401	$622,776	$435,590	$754,180
Contingency	$363,715	$404,828	$445,941	$487,053	$360,399	$592,098
Total project CapEx:	**$5,320,870**	**$5,993,109**	**$6,665,347**	**$7,337,586**	**$5,151,889**	**$8,888,078**
CapEx per installed MW:	$8,868,117	$8,561,584	$8,331,684	$8,152,873	$5,724,321	$4,937,821

Table 6 : Summary of Construction Costs

For the detailed construction costs see Annex 1.

4.3 Further Study Required – System Integration

The installation of WTGs on the grid at Hopedale will require further electrical and mechanical studies, which are not part of the current scope of work and should be performed at a later stage to fully assess the project viability. The results of these studies will determine whether additional control and communication equipment needs to be added to the system. It should be noted that since it is not currently known if any additional equipment will be required, no cost was included for such components in any of the simulations at this stage. The energy costs presented in the following section include no allocation for additional control and communication equipment.

4.4 Penetration and Energy Cost

The cost of energy for each option is calculated based on the total cost of producing the required quantity of energy during the life of the project and the total amount of energy produced. Costs are based on the cost of borrowed capital for CapEx, increasing fuel costs and energy demand as well as anticipated discount rate (inflation) over the duration of the project. All costs presented in this report are based on the average long term marginal cost of debt of 6.48% provided by NLH. However this historical value may not be representative of future interest rates and a different value could have a significant impact on the cost of energy for configurations using WTGs because of the large investment required. For information purposes, the resulting cost of energy associated with an interest rate of 4.5% was included in the Figure 1 : Average Cost of Energy.

The level of penetration of wind energy in the energy pool at Hopedale is proportional to the number of WTG installed on site. This value represents the total amount of power produced by wind turbines over the project life divided by the total amount of power used.

The results for average cost of energy and wind penetration over the expected project life of 20 years are shown in the figure below. From this figure, it can clearly be seen that there are

configurations using either WTG model that produce a COE lower than the base case. However, the EWT900 results in a much lower overall cost of energy and a much higher wind penetration level than the NPS100. The design methodology leading to these results was provided in Section 3.

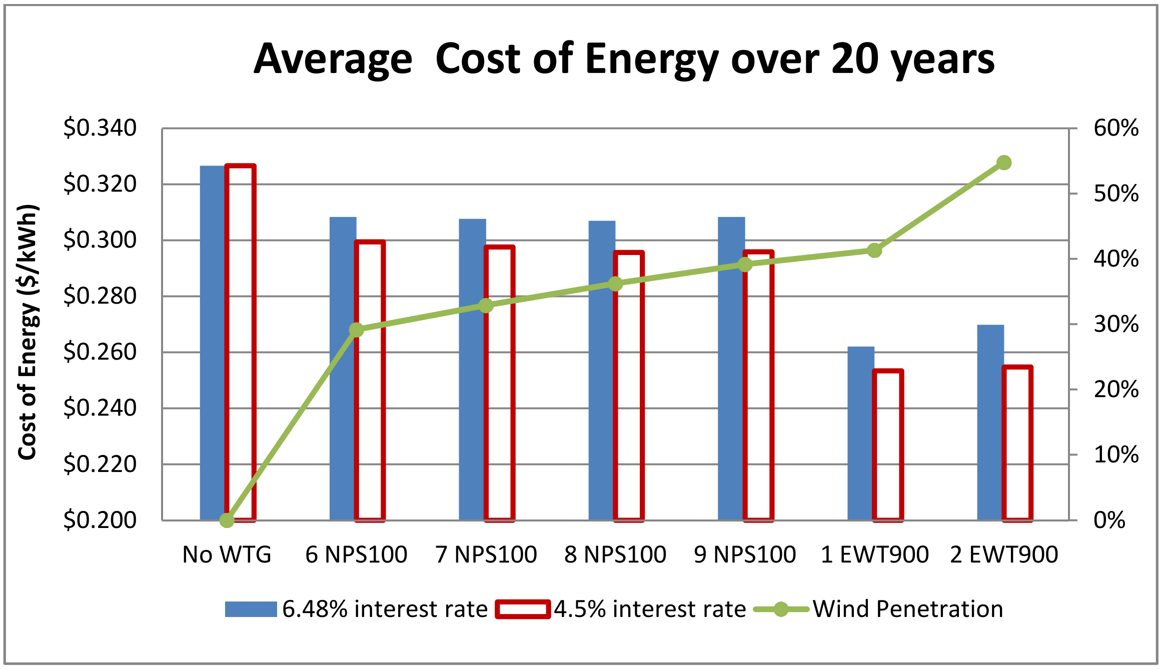

Figure 1 : Average Cost of Energy

4.5 Evolution of Cost of Energy

Figure 2 : Evolution of Cost of Energy shows the evolution of the non-discounted cost of power over the 20 years of the project life. It illustrates that the inclusion of more WTGs or larger WTGs in the energy mix reduces the impact of rising fuel costs on the average cost of energy over the project life. The graph also indicates that scenarios with the EWT900 turbine result in much lower energy costs. Scenarios with the NPS100 also result in a lower energy cost than the base case, but the cost is significantly higher than the results with the EWT900.

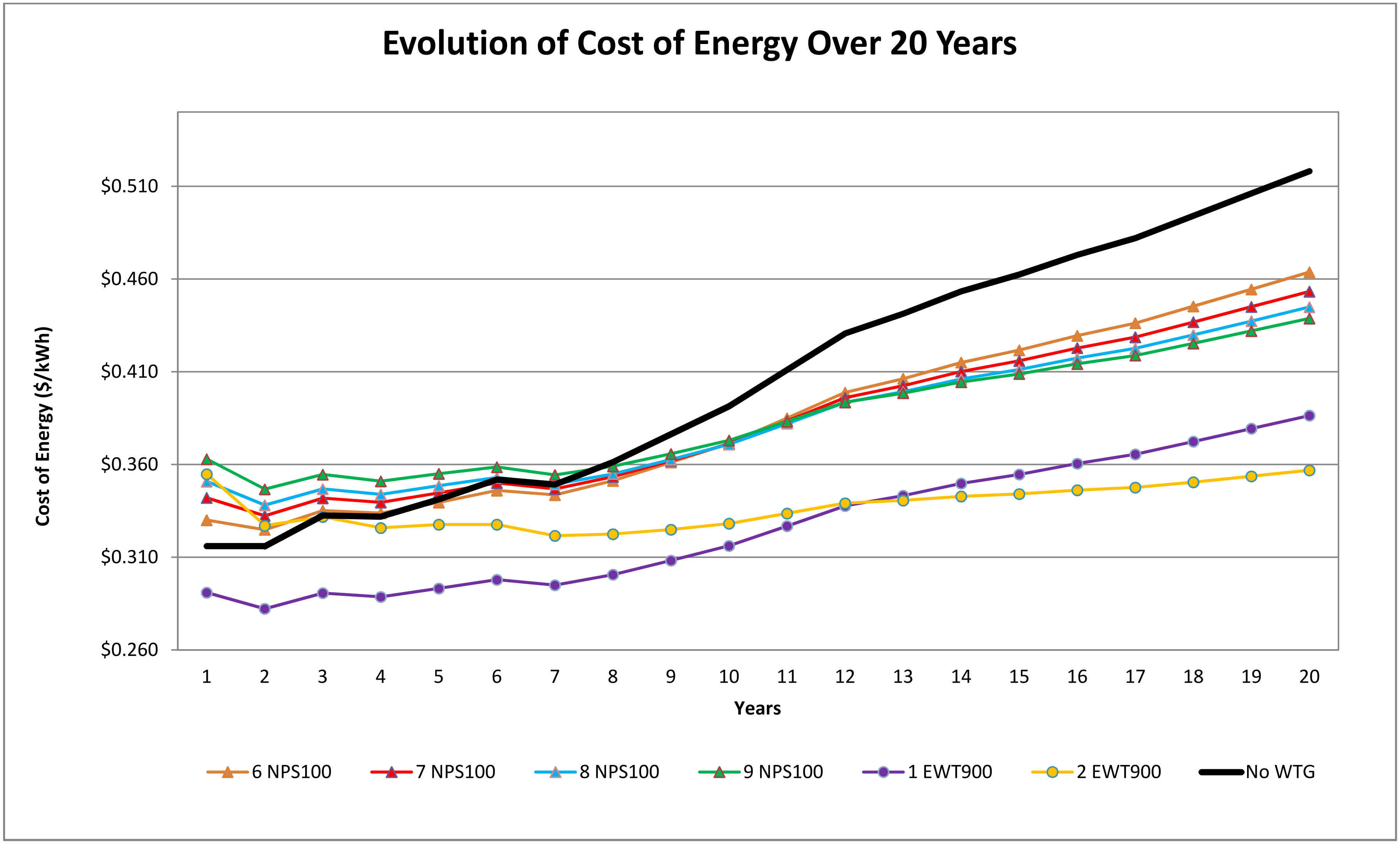

Figure 2 : Evolution of Cost of Energy

4.6 Fuel Costs and Excess Wind Energy

The average yearly fuel costs provide a good indication of the system reliance on fossil fuels for operation. The greater the installed wind capacity, the lower the annual fuel costs. However because of the magnitude and variability of electrical load on site, above a certain quantity of turbines, not all the energy produced by the turbines can be used by the system, causing the WTG to be less efficient.

The following figure shows the average yearly fuel costs for each configuration as well as the associated percentage fuel saved. The percentage of wasted WTG energy is also shown.

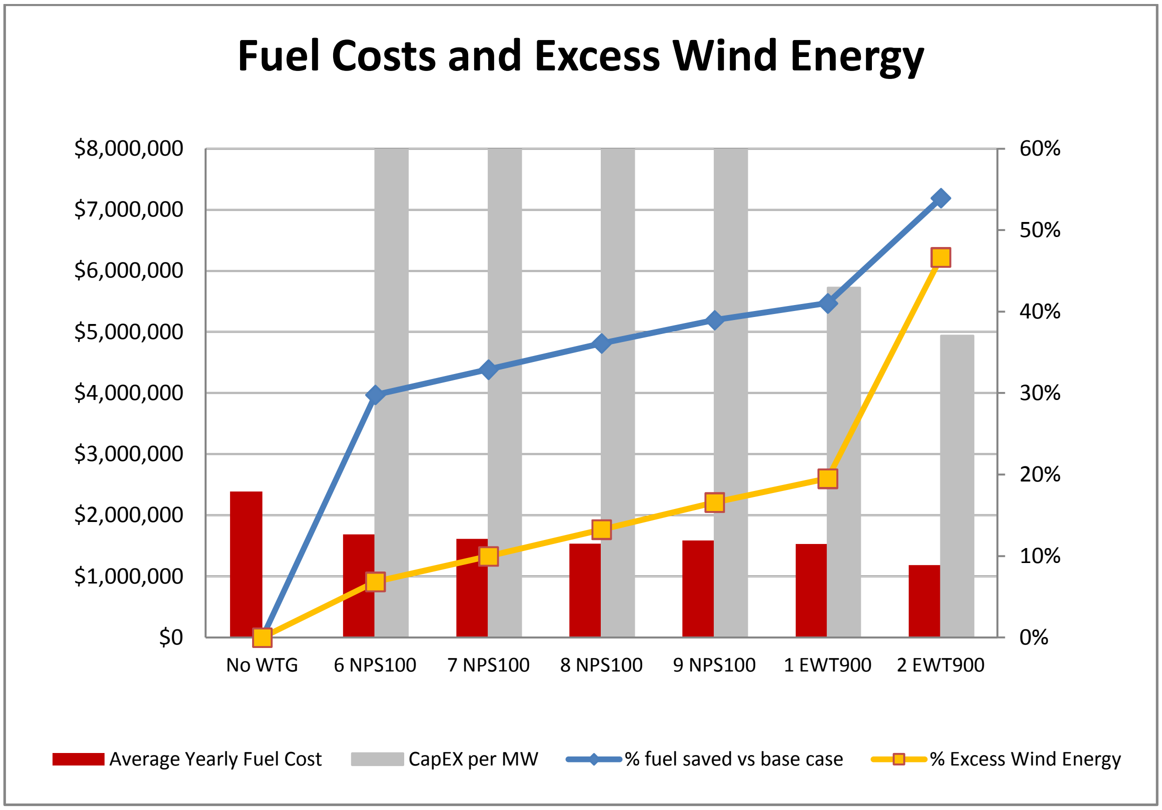

Figure 3 : Fuel Costs and Excess Wind Energy

4.7 Avoided Greenhouse Gas Emissions

The addition of renewable energy to the Cartwright electrical grid would have an impact on the amount of Greenhouse Gas (GHG) emissions resulting from energy production. NLH specified that it uses a value of 2.791 kg of CO_2 for each liter of diesel burned in the gensets it operates. Based on this number, Hatch calculated that the amount of avoided GHG emissions for each project configuration is as follows:

Case	Avoided Emissions of CO_2 (tonnes) over 1 Year	Avoided Emissions of CO_2 (tonnes) over 20 years
No WTG	0	0
6 NPS100	1,466	29,316
7 NPS100	1,619	32,376
8 NPS100	1,777	35,531
9 NPS100	1,917	38,340
1 EWT900	2,019	40,373
2 EWT900	2,654	53,076

Table 7 : Avoided Emissions of CO_2

Note: As of 2010, total Newfoundland and Labrador Green house gas emissions were 8.9 million tonnes per year, so avoided emissions by the installation of 1 EWT900 WTG at Hopedale would be equal to 0.023 % of total Provincial emissions.

4.8 Qualitative Comparison of WTG Models

The results presented in Section 4.1 clearly highlight the difference in wind penetration and energy cost between the two turbines being considered. The NPS100 is a small wind turbine that is easier to deploy yet has limited control capabilities, while the EWT900 is a full-size turbine with a large rotor diameter and the full control package associated with a utility scale turbine. Both turbines have an excellent track record in arctic conditions, making both potential candidates for the application. On the economic aspect, though the cost estimates will need to be validated in the next phase of the project, the cost per installed kW is much lower for the larger turbine which is generally common within the wind industry. Consequently, the energy produced comes at a lower price for the EWT900 than the NPS100. On the electrical side, the EWT is oversized for the application and produces much more energy than the NPS. Accordingly, the amount of excess energy by the EWT WTG is far above the NPS model, however the overall cost of useful energy remains lower for the EWT. The excess energy is expected to be easier to manage on the EWT as well, since it has active curtailment and derating management capabilities. From an environmental perspective, the EWT allows for more avoided emissions than the NPS. The practical O&M aspect also favors the EWT, as the manufacturer offers O&M options through long term contracts and, under certain circumstances, will even offer an availability warranty.

The size of the EWT900 makes for a more complex deployment, construction and installation. The logistical capabilities, including the remoteness, of the Hopedale port and community are not well documented and may make the delivery, unloading, transport and installation of the

EWT turbine much more expensive than budgeted at present. This could be a fatal flaw associated with the EWT900 WTG. A full logistic analysis is strongly recommended to confirm whether the installation of the EWT900 WTG is feasible. It needs to be noted that turbine models between 100 KW to 900 KW are not commonly available from many OEMs especially for use in arctic conditions. A more detailed turbine selection process should be initiated in following phases of the project.

The table below shows a comparison between the two models with "X" indicating superiority in each category:

Category	NPS100	EWT900
Track Record	X	X
Turbine Cost		X
Energy Poduction		X
Control Capabilities		X
Avoided Emissions		X
O&M		X
Logistics	X	

Table 8 : WTG qualitative comparison

Figure 4 highlights the size differences between the NPS100 and the EWT900.

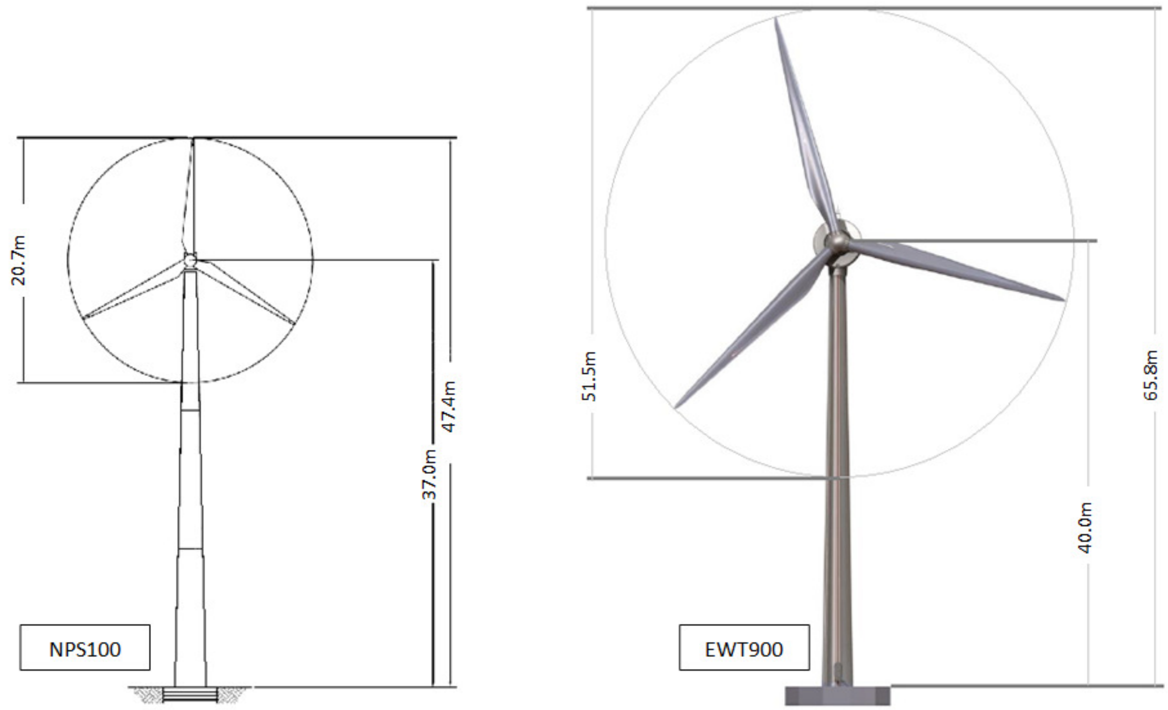

Figure 4 : Turbines Size

5. Conclusion and Recommendations

Based on the system modeling and preliminary economic analysis performed by Hatch, the optimal system design for Hopedale the installation of one EWT900 WTGs. This result is based on the anticipated energy production of the existing gensets and the future wind turbines, according to the functional specifications of the local grid as provided by NLH. It should be noted that several components were excluded from this analysis, including the value of avoided GHG emissions, the level of community acceptance and government policy implications. It is recommended that NLH gather more information on these topics prior to moving forward with further assessments of project viability.

It is important to note that a detailed mechanical and electrical stability study was not performed at this stage. It is critical that such a study be performed in advance of the detailed design stage to determine the impacts of adding WTGs to the existing system, as well as the actual limitations of the current grid. Furthermore, a logistics analysis needs to be completed to determine whether the local capabilities allow for the installation of the EWT900 turbine.

ELB
Attachment(s)/Enclosure :
Annex 1 - Construction Costs.pdf
H340923-0000-05-124-0002_rev2.pdf (Hopedale Final Wind Resource Assessment Report)

Annex 1 – Construction Costs Used in HOMER Model

Costs to add turbines at various sites	NPS100	EWT900
WTG O&M ($/y)	$ 20,000	$ 60,000
Project development (lump sum)	$ 200,000	$ 200,000
Engineering and studies (lump sum)	$ 175,000	$ 175,000
Deployment cost (lump sum)	$ 75,000	$ 175,000
New electrical line ($/km)	$ 250,000	$ 250,000
New road ($/km)	$ 300,000	$ 300,000
Interconnection to local grid	$ 50,000	$ 50,000
Rock blasting (per turbine)	$ 20,000	$ 250,000
Concrete batch plant deployment	$ 25,000	$ 25,000
Foundation concrete content (cubic yards)	29.09	250.00
Concrete cost ($/cubic yard)	$ 900	$ 900
Other foundation material and labor	$ 25,000	$ 125,000
Total foundation cost (per turbine)	$ 71,180	$ 600,000
Turbine purchase cost (per turbine)	$ 325,000	$ 2,000,000
Extra turbine cost for arctic version (per turbine)	$ 20,000	$ -
Turbine transportation to site (per turbine)	$ 45,000	$ 250,000
Turbine installation (per turbine)	$ 50,000	$ 125,000
Turbine peak power output (kW)	100	900
Project management (% of total project cost	10%	10%
Construction management (% of construction costs)	6%	6%
Contingency for turbine components	5%	5%
Contingency for construction costs	10%	10%

Appendix H: Hybrid system modelling and optimisation report - Makkovik

Project Report

November 9, 2015

Coastal Labrador Wind Monitoring Program

Makkovik Hybrid System Modeling and Optimization

Distribution

Trevor Andrew – NLH
Asim Haldar – NLH
Bob Moulton – NLH
Timothy Manning – NLH
Terry Gardiner – NLH
Louis Auger – Hatch
Dany Awad – Hatch
Ève-Line Brouillard - Hatch

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1. Introduction, Objectives and Scope of Work

As part of the project titled, Coastal Labrador Wind Monitoring Program, Newfoundland and Labrador Hydro (NLH) mandated Hatch to complete a wind monitoring campaign to determine the feasibility of adding Wind Turbine Generators (WTG) to Labrador isolated communities of Nain, Hopedale, Makkovik, Cartwright and L'Anse au Loup. This report presents the methodology and results related to Makkovik.

The wind monitoring periods are listed in the table below and additional information on the wind monitoring campaigns can be found in the respective WRA reports completed for each community.

	Date of first data recorded	Date of last data recorded
Nain (mast 2601)	30 October 2013	19 July 2015
Hopedale (mast 2602)	27 October 2013	19 July 2015
Makkovik (mast 2603)	25 October 2013	19 July 2015
Cartwright (mast 2605)	5 November 2013	13 July 2015
L'Anse au Loup (mast 2604)	5 October 2013	27 April 2015

Table 1 : Sites and Monitoring Periods

The specific objectives of the mandate were to provide the potential wind turbine capacity that can be installed on these 5 communities, the potential wind penetration and the associated cost breakdown for development, construction and operations (CapEx and OpEx).

2. Overview of Existing Diesel Grid on Site

Makkovik is a small community in Northern Labrador and consequently has a small electrical demand compared to neighbouring communities. The electrical equipment on site as well as electrical load and future forecast are defined below, based on the information provided by NLH.

2.1 Installed Power Generation Equipment

The power grid operated by NLH in Makkovik currently relies on three (3) diesel generators (Gensets). This configuration is common for isolated communities where it would be too costly to interconnect to the main provincial grid. The gensets currently on site include the following units:

Unit Number	Unit kW	Brand	Model	RPMs	Purchase Year
(G1)2059	635	CAT	D-3412	1800	2000
(G2)3033	450	CAT	D-3412	1800	1992
(G3)2029	465	CAT	D-3412	1800	1990

Table 2 : Diesel Gensets on Site

2.2 Generator Control Scheme

The gensets on site are managed by an automated control scheme. NLH explained that the control logic aims to minimize the number and size of the gensets running at any given time while also insuring sufficient spinning reserve to meet increases in load. To do so, whenever the unit running is operating at less than 75% load ratio, the system switches to a smaller unit, if available. Whenever the unit running is loaded at more than 85%, the system switches to a larger unit, if available, or starts a second generator to share the load.

The minimum load ratio for all gensets operated by NLH is 30%.

These control parameters are important for the modeling part of the process and will be discussed later.

2.3 Electric Load

The electric load at Makkovik varies a little between winter and summer months. NLH provided the 2014 monthly average hourly electrical load. This data is shown in the table below:

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Makkovik	574	502	449	389	404	308	358	507	348	391	400	521

Table 3 : Average Load (kW)

Furthermore, a monitoring system was recently installed by NLH to record 15 minute electrical production from each genset. The data recorded by this system, which covers the period of December 2014 to April 2015, was made available for inclusion in the model. This dataset provided the basis of calculation for the production of a daily hourly load profile, an essential component of the modeling exercise.

It should be noted that the 15 minute dataset provided shows that more genset hours are required to produce the energy for the site compared to what is predicted by the modelling software.

2.4 Forecasted Load and Fuel Price

NLH provided information showing anticipated growth of peak hourly power demand and total yearly energy for the years 2015 to 2033 for Makkovik. The expected average fuel cost for each year was also supplied for the same period. The table below summarizes this information.

Makkovik	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033
Gross Peak (kW)	965	975	985	995	1,004	1,017	1,027	1,037	1,047	1,057	1,067	1,077	1,087	1,097	1,107	1,117	1,127	1,137	1,148
Net Peak (kW)	921	931	941	951	960	973	983	993	1,003	1,013	1,023	1,033	1,043	1,053	1,063	1,073	1,083	1,093	1,104
Gross Energy (MWh)	4,468	4,510	4,550	4,592	4,633	4,675	4,717	4,759	4,802	4,846	4,887	4,928	4,970	5,012	5,055	5,098	5,141	5,185	5,229
Net Energy (MWh)	4,175	4,214	4,252	4,292	4,330	4,369	4,408	4,448	4,488	4,528	4,567	4,605	4,645	4,684	4,724	4,764	4,805	4,845	4,887
Fuel Price ($/L)	$0.93	$0.99	$0.99	$1.02	$1.06	$1.05	$1.09	$1.15	$1.20	$1.27	$1.34	$1.38	$1.42	$1.46	$1.49	$1.53	$1.57	$1.61	$1.66

Table 4 : Forecasted load and fuel price growth (2015-2033)

The forecasted load growth and fuel price increase were important components in the evaluation of the various available system configurations as the objective was to find the most desirable system over the life of the project.

3. Design methodology

3.1 Software Used

The electrical system and integration of the wind turbines was modelled and simulated using HOMER (Hybrid Optimization of Multiple Electric Renewables). This software is specifically used to model and optimize the configuration of micro-grid systems composed of multiple components, which can include wind turbine generators, photovoltaic solar panels, hydroelectric generators, batteries as well as generators running on various types of fuel. Using inputs comprising electric load profile, electrical architecture of the system (DC vs AC, etc.), renewable resources as well as costs for the purchase, operation and replacement of each component, HOMER can investigate multiple configurations and produce insight as to how to minimize the Levelized Cost of Energy (LCOE) or fuel used by the system. In the context of the current assignment, the outputs of the software were integrated in MS Excel spreadsheets to include electrical load and fuel cost variations over time with the aim of selecting the most efficient solution over the life of the project.

3.2 Model Building

NLH provided valuable information related to the historical operating performance of the existing system. The data provided included operations and maintenance (O&M) costs and overhaul costs, as well as data linking electrical production and fuel consumption. Each genset model was created in HOMER to accurately reflect these parameters, as well as the specific fuel curve provided by NLH.

The average monthly electrical load provided by NLH was used as the basis for the load profile included in the model. The 15 minute genset production dataset, covering a 5 month period, was used to establish a daily electric production profile. The assumption was made that the electric production at any given time was equal to the electric demand, so the daily load profile would be the same as the daily production profile. This daily load profile proved to be similar in shape for all 5 months of data provided, with differing magnitudes across months. As such, the assumption was made that the typical daily load profile shape would be the same for all 12 months but that it would be scaled to reflect the monthly averages provided by NLH. This daily load profile for each month was integrated as the electric load for the project. HOMER uses the base hourly profile and introduces hour to hour and day to day random variations based on parameters defined by the user. The result is a random time series for the load that has a pattern similar to the actual load.

At this point an iteration of the model was run in a configuration representing the equipment present on site to verify that HOMER would yield results similar to the numbers provided by NLH. The energy cost, generator run hours and quantity of fuel burned per year all came to within 5% of the numbers provided by NLH for project year 1. This provided validation that the model could be relied upon to accurately represent the system.

A preliminary turbine selection for the Makkovik project was completed as part of the Wind Resource assessment phase and two WTGs models from two different OEMs were selected; additional information on the turbine selection methodology is available in the WRA report. These turbines are the Northern Power Systems 100kW arctic version (NPS100) and the Emergya Wind Technologies 900kW (EWT900). Both WTGs were modeled in HOMER based on manufacturer provided specifications. The long term wind resource calculated in the wind resource assessment campaign was integrated in the model and the energy production predicted by the software WindFarmer for each turbine model was compared with the energy calculated by HOMER. WindFarmer is routinely used to optimize wind farm layouts with regard to energy, topography and restrictions and to estimate the energy production. WindFarmer outputs are considered more accurate than HOMER for this aspect. Following some minor model adjustments, the comparison showed that the HOMER results were similar to the WindFarmer results within a few percent, confirming that the simulation used realistic wind energy production numbers.

The following assumptions were made during the optimization process and in the simulation phase:

- The daily load profile was derived from time series and historical values provided by NLH
- Fuel costs and load growth were based on information provided by NLH, as presented in Section 2.4
- An inflation rate of 2.21% and average NLH long term marginal cost of debt (rounded) of 6.48% were used, according to historical values specified by NLH
- Construction costs have been defined based on information from manufacturers and historical values from past projects

3.3 System Sizing and Optimization

The sizing and optimisation of the proposed wind project for Makkovik was determined through an iterative process. HOMER simulations were run using varying numbers of each WTG model selected in the previous phase. The objective of the iterations was to determine the number of WTGs for each model that would result in the lowest calculated cost of energy (COE).

The outputs from Homer were integrated in Excel spreadsheets to evaluate the impact of increasing fuel costs, electrical demand, inflation and cost of borrowed capital. Some key metrics were identified to compare the various configurations and determine the most economically viable scenarios. The results are presented in the following section.

4. Results

4.1 Proposed Configuration

Based on the modeling performed in HOMER, the optimal number of turbines for integration in the Makkovik system is 5 when considering the NPS100 and 1 when considering the EWT900. Since the turbines are very different in scale, a qualitative comparison between the models is presented at the end of the current section. The table below shows a summary of the results for integration of various numbers of each WTG model.

	Fuel saved vs base case	Yearly Fuel Savings	Wind Penetration	WTG energy over 20 yrs (kWh)	Excess energy over 20 yrs (kWh)	Cost of Energy ($/kWh)
No WTG	0%	$0	0%	0	0	$0.3249
3 NPS100	22.3%	$342,136	22.8%	20,729,500	262,833	$0.3113
4 NPS100	28.5%	$439,416	29.4%	27,639,360	1,223,202	$0.3050
5 NPS100	33.5%	$517,163	34.8%	34,549,260	3,326,212	$0.3046
6 NPS100	37.3%	$576,633	38.9%	41,459,020	6,539,543	$0.3070
1 EWT900	42.6%	$660,449	44.7%	62,032,680	21,872,061	$0.2788
2 EWT900	50.7%	$787,027	53.5%	124,065,340	76,030,524	$0.3265

Table 5 : Summary of Results

The estimated energy production of each proposed configuration accounts for the possible losses in a wind farm, such as wake, aerodynamic, electrical, operational and power curve losses. The figures of availability should be defined with more accuracy at the detailed turbine selection stage, based on statistics for the turbine selected and after confirmation of the O & M strategy and review of the draft O&M contract if applicable. Based on preliminary manufacturer's discussions, other factors that will need to be considered for availability include the benefit of having a greater number of turbine units due to potential difficulties to execute repairs in the winter months. This will need to be analyzed as part of the turbine selection process.

As noted in Sections 4.2 and 4.3, the cost of energy does not include all applicable costs. As such, this preliminary cost of energy provides an indicator that, at this point, the project is viable and warrants further study. Additional costs not reflected include mechanical and electrical stability studies, system integration costs, control and communications system costs, as well as detailed logistic studies, plant detailed design and optimization.

4.2 Construction Costs

The total estimated cost of building a wind farm at Makkovik includes development, turbine, construction and project management. Project contingency was also included, at 5% for WTG components and 10% for construction costs. Additional integration and pre-development costs include logistics study, integration study, electrical and mechanical stability studies have not been included. System integration costs have also been left out of the equation, as well as any associated integration and communication equipment costs since this scope were not included in the present project. All of the aforementioned studies would need to be completed to fully assess the viability of the project. The following table shows a summary of the included project costs for various iterations:

	NPS 100				EWT 900	
Number of units	**3**	**4**	**5**	**6**	**1**	**2**
Development costs	$375,000	$375,000	$375,000	$375,000	$375,000	$375,000
Turbine costs	$1,320,000	$1,760,000	$2,200,000	$2,640,000	$2,375,000	$4,750,000
Construction costs	$798,752	$932,503	$1,066,254	$1,200,004	$1,372,700	$2,241,900
Project management	$249,375	$306,750	$364,125	$421,500	$412,270	$736,690
Contingency	$208,313	$249,425	$290,538	$331,650	$334,747	$572,859
Total project CapEx:	**$2,951,440**	**$3,623,679**	**$4,295,917**	**$4,968,155**	**$4,869,717**	**$8,676,449**
CapEx per installed MW:	$9,838,134	$9,059,196	$8,591,834	$8,280,259	$5,410,797	$4,820,249

Table 6 : Summary of Construction Costs

For the detailed construction costs see Annex 1.

4.3 Further Study Required – System Integration

The installation of WTGs on the grid at Makkovik will require further electrical and mechanical studies, which are not part of the current scope of work and should be performed at a later stage to fully assess the project viability. The results of these studies will determine whether additional control and communication equipment needs to be added to the system. It should be noted that since it is not currently known if any additional equipment will be required, no cost was included for such components in any of the simulations at this stage. The energy costs presented in the following section include no allocation for additional control and communication equipment.

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The cost of energy for each option is calculated based on the total cost of producing the required quantity of energy during the life of the project and the total amount of energy produced. Costs are based on the cost of borrowed capital for CapEx, increasing fuel costs and energy demand as well as anticipated discount rate (inflation) over the duration of the project. All costs presented in this report are based on the average long term marginal cost of debt of 6.48% provided by NLH. However this historical value may not be representative of future interest rates and a different value could have a significant impact on the cost of energy for configurations using WTGs because of the large investment required. For information purposes, the resulting cost of energy associated with an interest rate of 4.5% was included in the Figure 1 : Average Cost of Energy.

The level of penetration of wind energy in the energy pool at Makkovik is proportional to the number of WTG installed on site. This value represents the total amount of power produced by wind turbines over the project life divided by the total amount of power used.

The results for average cost of energy and wind penetration over the expected project life of 20 years are shown in the figure below. From this figure, it can clearly be seen that there are configurations using either WTG model that produce a COE lower than the base case. However, the EWT900 results in a much lower overall cost of energy and a much higher wind penetration level than the NPS100. The design methodology leading to these results was provided in Section 3.

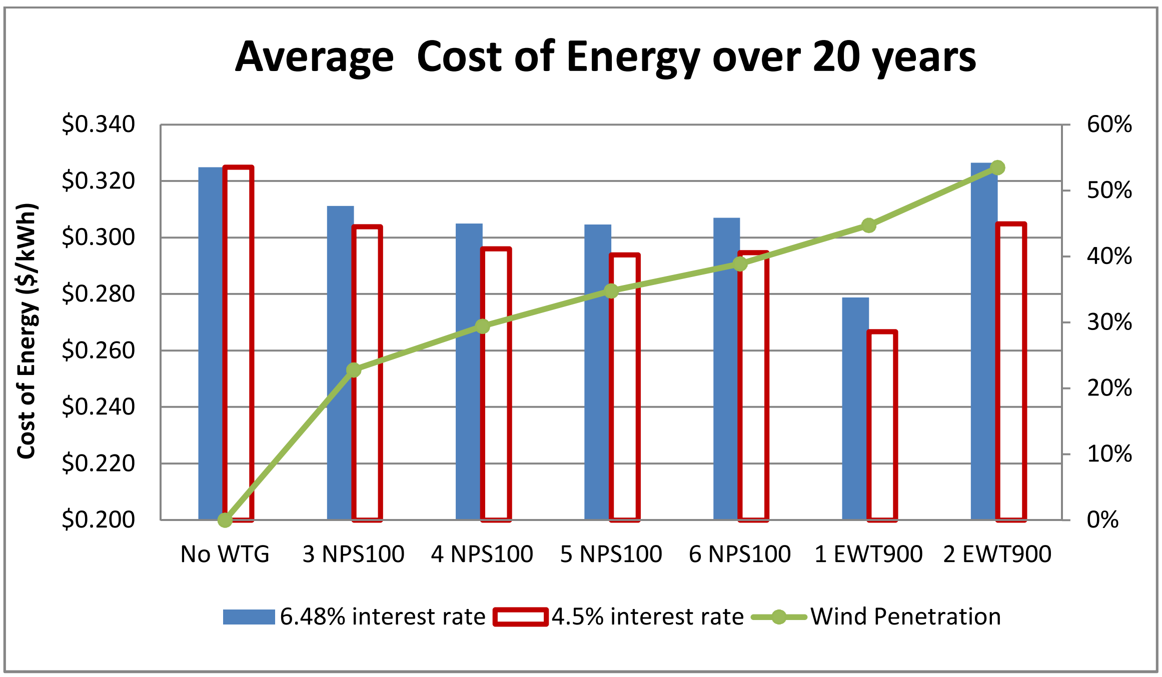

Figure 1 : Average Cost of Energy

4.5 Evolution of Cost of Energy

Figure 2 : Evolution of Cost of Energy shows the evolution of the non-discounted cost of power over the 20 years of the project life. It illustrates that the inclusion of more WTGs or

larger WTGs in the energy mix reduces the impact of rising fuel costs on the average cost of energy over the project life. The graph also indicates that scenarios with the EWT900 turbine result in much lower energy costs. Scenarios with the NPS100 also result in a lower energy cost than the base case, but the cost is significantly higher than the results with the EWT900.

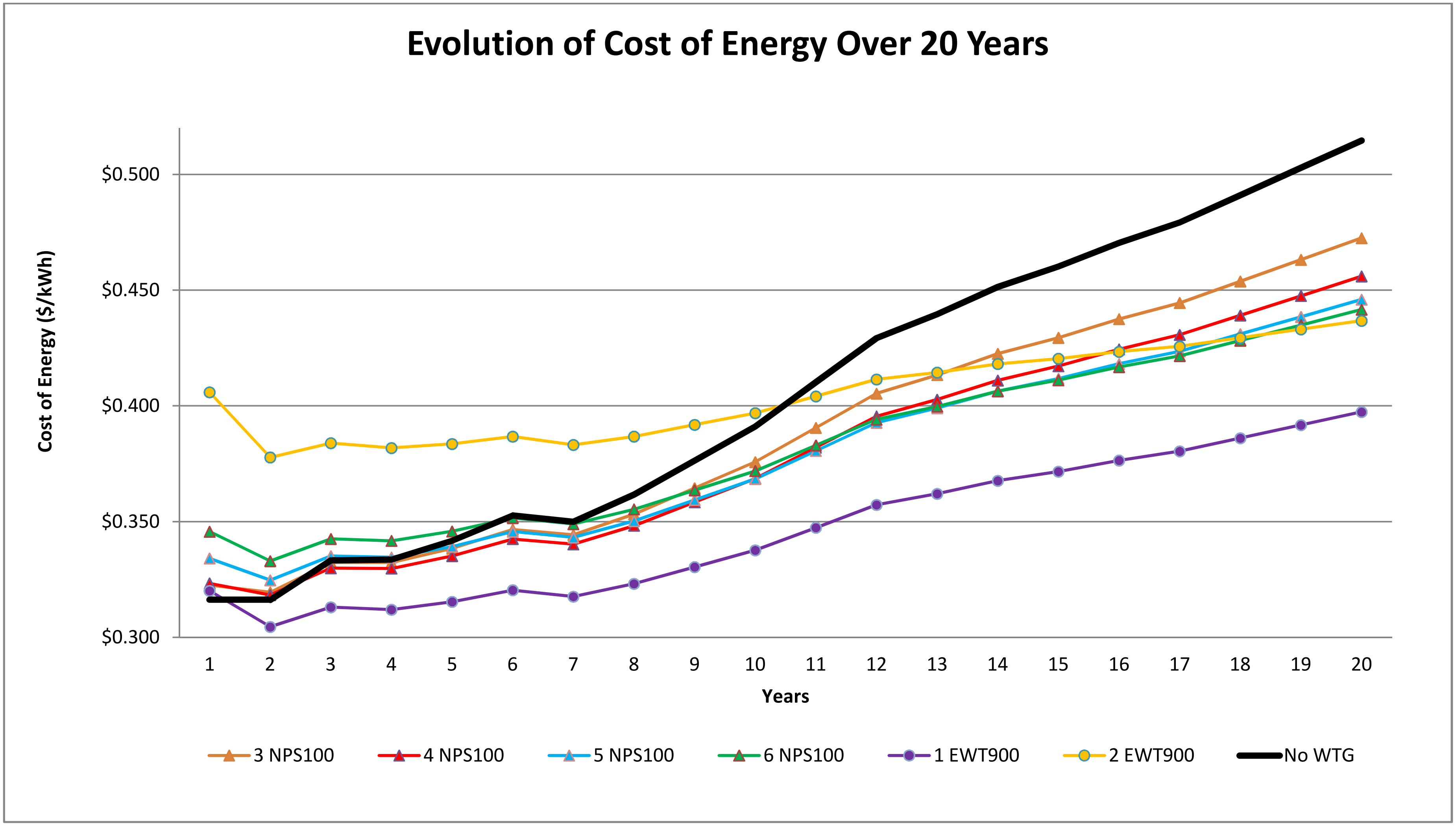

Figure 2 : Evolution of Cost of Energy

4.6 Fuel Costs and Excess Wind Energy

The average yearly fuel costs provide a good indication of the system reliance on fossil fuels for operation. The greater the installed wind capacity, the lower the annual fuel costs. However because of the magnitude and variability of electrical load on site, above a certain quantity of turbines, not all the energy produced by the turbines can be used by the system, causing the WTG to be less efficient.

The following figure shows the average yearly fuel costs for each configuration as well as the associated percentage fuel saved. The percentage of wasted WTG energy is also shown.

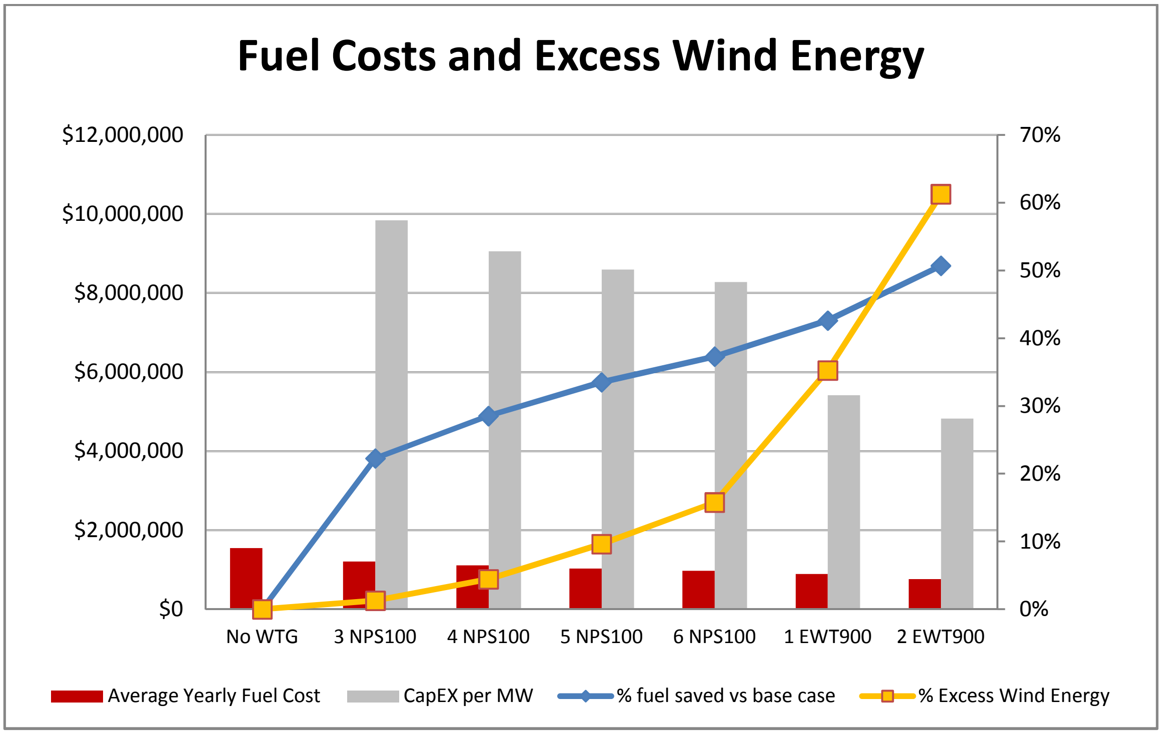

Figure 3 : Fuel Costs and Excess Wind Energy

4.7 Avoided Greenhouse Gas Emissions

The addition of renewable energy to the Cartwright electrical grid would have an impact on the amount of Greenhouse Gas (GHG) emissions resulting from energy production. NLH specified that it uses a value of 2.791 kg of CO_2 for each liter of diesel burned in the gensets it operates. Based on this number, Hatch calculated that the amount of avoided GHG emissions for each project configuration is as follows:

Case	Avoided Emissions of CO_2 (tonnes) over 1 Year	Avoided Emissions of CO_2 (tonnes) over 20 years
No WTG	0	0
3 NPS100	758	15,164
4 NPS100	971	19,427
5 NPS100	1,141	22,810
6 NPS100	1,269	25,388
1 EWT900	1,450	29,009
2 EWT900	1,726	34,517

Table 7 : Avoided Emissions of CO_2

Note: As of 2010, total Newfoundland and Labrador Green house gas emissions were 8.9 million tonnes per year, so avoided emissions by the installation of 1 EWT900 WTG at Makkovik would be equal to 0.016 % of total Provincial emissions.

4.8 Qualitative Comparison of WTG Models

The results presented in Section 4.1 clearly highlight the difference in wind penetration and energy cost between the two turbines being considered. The NPS100 is a small wind turbine that is easier to deploy yet has limited control capabilities, while the EWT900 is a full-size turbine with a large rotor diameter and the full control package associated with a utility scale turbine. Both turbines have an excellent track record in arctic conditions, making both potential candidates for the application. On the economic aspect, though the cost estimates will need to be validated in the next phase of the project, the cost per installed kW is much lower for the larger turbine which is generally common within the wind industry. Consequently, the energy produced comes at a lower price for the EWT900 than the NPS100. On the electrical side, the EWT is oversized for the application and produces much more energy than the NPS. Accordingly, the amount of excess energy by the EWT WTG is far above the NPS model, however the overall cost of useful energy remains lower for the EWT. The excess energy is expected to be easier to manage on the EWT as well, since it has active curtailment and derating management capabilities. From an environmental perspective, the EWT allows for more avoided emissions than the NPS. The practical O&M aspect also favors the EWT, as the manufacturer offers O&M options through long term contracts and, under certain circumstances, will even offer an availability warranty.

The size of the EWT900 makes for a more complex deployment, construction and installation. The logistical capabilities, including the remoteness, of the Makkovik port and community are not well documented and may make the delivery, unloading, transport and installation of the

EWT turbine much more expensive than budgeted at present. This could be a fatal flaw associated with the EWT900 WTG. A full logistic analysis is strongly recommended to confirm whether the installation of the EWT900 WTG is feasible. It needs to be noted that turbine models between 100 KW to 900 KW are not commonly available from many OEMs especially for use in arctic conditions. A more detailed turbine selection process should be initiated in following phases of the project.

The table below shows a comparison between the two models with “X” indicating superiority in each category:

Category	NPS100	EWT900
Track Record	X	X
Turbine Cost		X
Energy Poduction		X
Control Capabilities		X
Avoided Emissions		X
O&M		X
Logistics	X	

Table 8 : WTG qualitative comparison

Figure 4 highlights the size differences between the NPS100 and the EWT900.

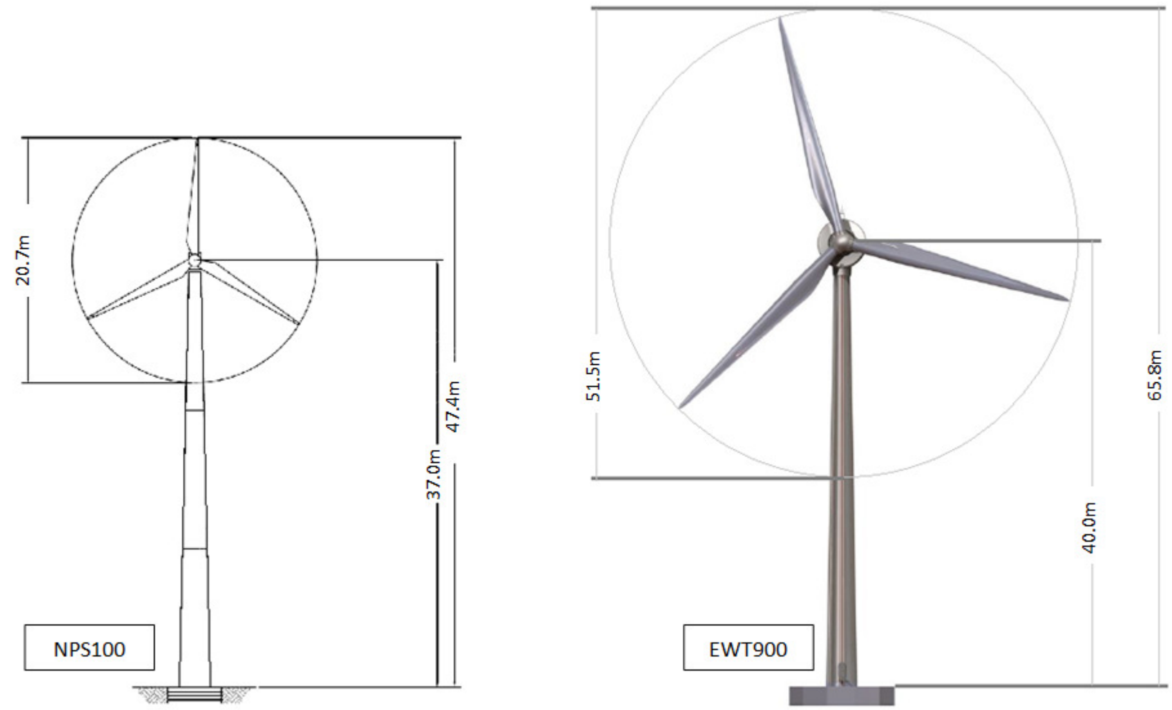

Figure 4 : Turbines Size

5. Conclusion and Recommendations

Based on the system modeling and preliminary economic analysis performed by Hatch, the optimal system design for Makkovik is the installation of one EWT900 WTGs. This result is based on the anticipated energy production of the existing gensets and the future wind turbines, according to the functional specifications of the local grid as provided by NLH. It should be noted that several components were excluded from this analysis, including the value of avoided GHG emissions, the level of community acceptance and government policy implications. It is recommended that NLH gather more information on these topics prior to moving forward with further assessments of project viability.

It is important to note that a detailed mechanical and electrical stability study was not performed at this stage. It is critical that such a study be performed in advance of the detailed design stage to determine the impacts of adding WTGs to the existing system, as well as the actual limitations of the current grid. Furthermore, a logistics analysis needs to be completed to determine whether the local capabilities allow for the installation of the EWT900 turbine.

ELB
Attachment(s)/Enclosure :
Annex 1 - Construction Costs.pdf
H340923-0000-05-124-0003_rev2.pdf (Makkovik Final Wind Resource Assessment Report)

Annex 1 – Construction Costs Used in HOMER Model

Costs to add turbines at various sites	NPS100	EWT900
WTG O&M ($/y)	$ 20,000	$ 60,000
Project development (lump sum)	$ 200,000	$ 200,000
Engineering and studies (lump sum)	$ 175,000	$ 175,000
Deployment cost (lump sum)	$ 75,000	$ 175,000
New electrical line ($/km)	$ 250,000	$ 250,000
New road ($/km)	$ 300,000	$ 300,000
Interconnection to local grid	$ 50,000	$ 50,000
Rock blasting (per turbine)	$ 20,000	$ 250,000
Concrete batch plant deployment	$ 25,000	$ 25,000
Foundation concrete content (cubic yards)	29.09	250.00
Concrete cost ($/cubic yard)	$ 900	$ 900
Other foundation material and labor	$ 25,000	$ 125,000
Total foundation cost (per turbine)	$ 71,180	$ 600,000
Turbine purchase cost (per turbine)	$ 325,000	$ 2,000,000
Extra turbine cost for arctic version (per turbine)	$ 20,000	$ -
Turbine transportation to site (per turbine)	$ 45,000	$ 250,000
Turbine installation (per turbine)	$ 50,000	$ 125,000
Turbine peak power output (kW)	100	900
Project management (% of total project cost	10%	10%
Construction management (% of construction costs)	6%	6%
Contingency for turbine components	5%	5%
Contingency for construction costs	10%	10%

Appendix I:
Hybrid system modelling and optimisation report - Cartwright

Project Report

November 9, 2015

Coastal Labrador Wind Monitoring Program

Cartwright Hybrid System Modeling and Optimization

Distribution

Trevor Andrew – NLH
Asim Haldar – NLH
Bob Moulton – NLH
Timothy Manning – NLH
Terry Gardiner – NLH
Louis Auger – Hatch
Dany Awad – Hatch
Ève-Line Brouillard - Hatch

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1. Introduction, Objectives and Scope of Work

As part of the project titled, Coastal Labrador Wind Monitoring Program, Newfoundland and Labrador Hydro (NLH) mandated Hatch to complete a wind monitoring campaign to determine the feasibility of adding Wind Turbine Generators (WTG) to Labrador isolated communities of Nain, Hopedale, Makkovik, Cartwright and L'Anse au Loup. This report presents the methodology and results related to Cartwright.

The wind monitoring periods are listed in the table below and additional information on the wind monitoring campaigns can be found in the respective WRA reports completed for each community.

	Date of first data recorded	Date of last data recorded
Nain (mast 2601)	30 October 2013	19 July 2015
Hopedale (mast 2602)	27 October 2013	19 July 2015
Makkovik (mast 2603)	25 October 2013	19 July 2015
Cartwright (mast 2605)	5 November 2013	13 July 2015
L'Anse au Loup (mast 2604)	5 October 2013	27 April 2015

Table 1 : Sites and Monitoring Periods

The specific objectives of the mandate were to provide the potential wind turbine capacity that can be installed on these 5 communities, the potential wind penetration and the associated cost breakdown for development, construction and operations (CapEx and OpEx).

2. Overview of Existing Diesel Grid on Site

Cartwright is an average size community in Labrador and consequently has a moderate electrical demand compared to neighbouring communities. The electrical equipment on site as well as electrical load and future forecast are defined below, based on the information provided by NLH.

2.1 Installed Power Generation Equipment

The power grid operated by NLH in Cartwright currently relies on four (4) diesel generators (Gensets). This configuration is common for isolated communities where it would be too costly to interconnect to the main provincial grid. The gensets currently on site include the following units:

Unit Number	Unit kW	Brand	Model	RPMs	Purchase Year
(G1)2036	450	CAT	D-3412	1800	1992
(G2)2086	600	CAT	C-27	1800	2009
(G3)2045	450	CAT	D-3412	1800	1993
(G4)2052	720	CAT	D-3412	1200	1998

Table 2 : Diesel Gensets on Site

2.2 Generator Control Scheme

The gensets on site are managed by an automated control scheme. NLH explained that the control logic aims to minimize the number and size of the gensets running at any given time while also insuring sufficient spinning reserve to meet increases in load. To do so, whenever the unit running is operating at less than 75% load ratio, the system switches to a smaller unit, if available. Whenever the unit running is loaded at more than 85%, the system switches to a larger unit, if available, or starts a second generator to share the load.

The minimum load ratio for all gensets operated by NLH is 30%.

These control parameters are important for the modeling part of the process and will be discussed later.

2.3 Electric Load

The electric load at Cartwright varies a little between winter and summer months. NLH provided the 2014 monthly average hourly electrical load. This data is shown in the table below:

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Cartwright	656	583	503	465	508	501	461	420	332	416	430	580

Table 3 : Average Load (kW)

Furthermore, a monitoring system was recently installed by NLH to record 15 minute electrical production from each genset. The data recorded by this system, which covers the period of December 2014 to April 2015, was made available for inclusion in the model. This dataset provided the basis of calculation for the production of a daily hourly load profile, an essential component of the modeling exercise.

It should be noted that the 15 minute dataset provided shows that more genset hours are required to produce the energy for the site compared to what is predicted by the modelling software.

2.4 Forecasted Load and Fuel Price

NLH provided information showing anticipated growth of peak hourly power demand and total yearly energy for the years 2015 to 2033 for Cartwright. The expected average fuel cost for each year was also supplied for the same period. The table below summarizes this information.

Cartwright	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033
Gross Peak (kW)	1,032	1,040	1,050	1,059	1,069	1,078	1,088	1,097	1,106	1,116	1,120	1,125	1,129	1,133	1,138	1,142	1,146	1,151	1,155
Net Peak (kW)	997	1,005	1,015	1,024	1,034	1,043	1,053	1,062	1,071	1,081	1,085	1,090	1,094	1,098	1,103	1,107	1,111	1,116	1,120
Gross Energy (MWh)	4,701	4,739	4,784	4,823	4,869	4,912	4,955	4,997	5,040	5,083	5,103	5,123	5,142	5,162	5,182	5,202	5,222	5,241	5,261
Net Energy (MWh)	4,500	4,536	4,580	4,617	4,661	4,702	4,743	4,784	4,825	4,866	4,885	4,904	4,923	4,942	4,961	4,980	4,998	5,017	5,036
Fuel Price ($/L)	$0.95	$1.01	$1.01	$1.05	$1.09	$1.08	$1.12	$1.17	$1.23	$1.30	$1.37	$1.41	$1.46	$1.49	$1.53	$1.56	$1.61	$1.65	$1.70

Table 4 : Forecasted load and fuel price growth (2015-2033)

The forecasted load growth and fuel price increase were important components in the evaluation of the various available system configurations as the objective was to find the most desirable system over the life of the project.

3. Design Methodology

3.1 Software Used

The electrical system and integration of the wind turbines was modelled and simulated using HOMER (Hybrid Optimization of Multiple Electric Renewables). This software is specifically used to model and optimize the configuration of micro-grid systems composed of multiple components, which can include wind turbine generators, photovoltaic solar panels, hydroelectric generators, batteries as well as generators running on various types of fuel. Using inputs comprising electric load profile, electrical architecture of the system (DC vs AC, etc.), renewable resources as well as costs for the purchase, operation and replacement of each component, HOMER can investigate multiple configurations and produce insight as to how to minimize the Levelized Cost of Energy (LCOE) or fuel used by the system. In the context of the current assignment, the outputs of the software were integrated in MS Excel spreadsheets to include electrical load and fuel cost variations over time with the aim of selecting the most efficient solution over the life of the project.

3.2 Model Building

NLH provided valuable information related to the historical operating performance of the existing system. The data provided included operations and maintenance (O&M) costs and overhaul costs, as well as data linking electrical production and fuel consumption. Each genset model was created in HOMER to accurately reflect these parameters, as well as the specific fuel curve provided by NLH.

The average monthly electrical load provided by NLH was used as the basis for the load profile included in the model. The 15 minute genset production dataset, covering a 5 month period, was used to establish a daily electric production profile. The assumption was made that the electric production at any given time was equal to the electric demand, so the daily load profile would be the same as the daily production profile. This daily load profile proved to be similar in shape for all 5 months of data provided, with differing magnitudes across months. As such, the assumption was made that the typical daily load profile shape would be the same for all 12 months but that it would be scaled to reflect the monthly averages provided by NLH. This daily load profile for each month was integrated as the electric load for the project. HOMER uses the base hourly profile and introduces hour to hour and day to day random variations based on parameters defined by the user. The result is a random time series for the load that has a pattern similar to the actual load.

At this point an iteration of the model was run in a configuration representing the equipment present on site to verify that HOMER would yield results similar to the numbers provided by NLH. The energy cost, generator run hours and quantity of fuel burned per year all came to within 5% of the numbers provided by NLH for project year 1. This provided validation that the model could be relied upon to accurately represent the system.

A preliminary turbine selection for the Cartwright project was completed as part of the Wind Resource assessment phase and two WTGs models from two different OEMs were selected; additional information on the turbine selection methodology is available in the WRA report. These turbines are the Northern Power Systems 100kW arctic version (NPS100) and the Emergya Wind Technologies 900kW (EWT900). Both WTGs were modeled in HOMER based on manufacturer provided specifications. The long term wind resource calculated in the wind resource assessment campaign was integrated in the model and the energy production predicted by the software WindFarmer for each turbine model was compared with the energy calculated by HOMER. WindFarmer is routinely used to optimize wind farm layouts with regard to energy, topography and restrictions and to estimate the energy production. WindFarmer outputs are considered more accurate than HOMER for this aspect. Following some minor model adjustments, the comparison showed that the HOMER results were similar to the WindFarmer results within a few percent, confirming that the simulation used realistic wind energy production numbers.

The following assumptions were made during the optimization process and in the simulation phase:

- The daily load profile was derived from time series and historical values provided by NLH
- Fuel costs and load growth were based on information provided by NLH, as presented in Section 2.4
- An inflation rate of 2.21% and average NLH long term marginal cost of debt (rounded) of 6.48% were used, according to historical values specified by NLH
- Construction costs have been defined based on information from manufacturers and historical values from past projects

3.3 System Sizing and Optimization

The sizing and optimisation of the proposed wind project for Cartwright was determined through an iterative process. HOMER simulations were run using varying numbers of each WTG model selected in the previous phase. The objective of the iterations was to determine the number of WTGs for each model that would result in the lowest calculated cost of energy (COE).

The outputs from Homer were integrated in Excel spreadsheets to evaluate the impact of increasing fuel costs, electrical demand, inflation and cost of borrowed capital. Some key metrics were identified to compare the various configurations and determine the most economically viable scenarios. The results are presented in the following section.

4. Results

4.1 Proposed Configuration

Based on the modeling performed in HOMER, the optimal number of turbines for integration in the Cartwright system is 5 when considering the NPS100 and 1 when considering the EWT900. Since the turbines are very different in scale, a qualitative comparison between the models is presented at the end of the current section. The table below shows a summary of the results for integration of various numbers of each WTG model.

	Fuel saved vs base case	Yearly Fuel Savings	Wind Penetration	WTG energy over 20 yrs (kWh)	Excess energy over 20 yrs (kWh)	Cost of Energy ($/kWh)
No WTG	0%	$0	0%	0	0	$0.323
4 NPS100	24.5%	$401,258	25.3%	24,954,620	735,458	$0.318
5 NPS100	29.3%	$480,421	30.4%	31,193,300	2,059,909	$0.316
6 NPS100	33.2%	$545,446	34.7%	37,432,060	4,256,070	$0.317
7 NPS100	36.3%	$538,852	38.0%	43,670,680	7,276,102	$0.322
1 EWT900	40.3%	$610,325	42.4%	57,969,780	17,376,152	$0.279
2 EWT900	49.3%	$769,412	52.2%	115,939,580	65,979,434	$0.320

Table 5 : Summary of Results

The estimated energy production of each proposed configuration accounts for the possible losses in a wind farm, such as wake, aerodynamic, electrical, operational and power curve losses. The figures of availability should be defined with more accuracy at the detailed turbine selection stage, based on statistics for the turbine selected and after confirmation of the O & M strategy and review of the draft O&M contract if applicable. Based on preliminary manufacturer's discussions, other factors that will need to be considered for availability include the benefit of having a greater number of turbine units due to potential difficulties to execute repairs in the winter months. This will need to be analyzed as part of the turbine selection process.

As noted in Sections 4.2 and 4.3, the cost of energy does not include all applicable costs. As such, this preliminary cost of energy provides an indicator that, at this point, the project is viable and warrants further study. Additional costs not reflected include mechanical and electrical stability studies, system integration costs, control and communications system costs, as well as detailed logistic studies, plant detailed design and optimization.

4.2 Construction Costs

The total estimated cost of building a wind farm at Cartwright includes development, turbine, construction and project management. Project contingency was also included, at 5% for WTG components and 10% for construction costs. Additional integration and pre-development costs include logistics study, integration study, electrical and mechanical stability studies have not been included. System integration costs have also been left out of the equation, as well as any associated integration and communication equipment costs since this scope were

not included in the present project. All of the aforementioned studies would need to be completed to fully assess the viability of the project. The following table shows a summary of the included project costs for various iterations:

	NPS 100				EWT 900	
Number of units	**4**	**5**	**6**	**7**	**1**	**2**
Development costs	$375,000	$375,000	$375,000	$375,000	$375,000	$375,000
Turbine costs	$1,760,000	$2,200,000	$2,640,000	$3,080,000	$2,375,000	$4,750,000
Construction costs	$1,136,553	$1,270,304	$1,404,054	$1,537,805	$1,343,550	$2,271,050
Project management	$327,155	$384,530	$441,905	$499,281	$409,355	$739,605
Contingency	$271,871	$312,983	$354,096	$395,209	$331,541	$576,066
Total project CapEx:	**$3,870,579**	**$4,542,817**	**$5,215,056**	**$5,887,294**	**$4,834,446**	**$8,711,721**
CapEx per installed MW:	$9,676,448	$9,085,635	$8,691,760	$8,410,420	$5,371,606	$4,839,845

Table 6 : Summary of Construction Costs

For the detailed construction costs see Annex 1.

4.3 Further Study Required – System Integration

The installation of WTGs on the grid at Cartwright will require further electrical and mechanical studies, which are not part of the current scope of work and should be performed at a later stage to fully assess the project viability. The results of these studies will determine whether additional control and communication equipment needs to be added to the system. It should be noted that since it is not currently known if any additional equipment will be required, no cost was included for such components in any of the simulations at this stage. The energy costs presented in the following section include no allocation for additional control and communication equipment.

4.4 Penetration and Energy Cost

The cost of energy for each option is calculated based on the total cost of producing the required quantity of energy during the life of the project and the total amount of energy produced. Costs are based on the cost of borrowed capital for CapEx, increasing fuel costs and energy demand as well as anticipated discount rate (inflation) over the duration of the project. All costs presented in this report are based on the average long term marginal cost of debt of 6.48% provided by NLH. However this historical value may not be representative of future interest rates and a different value could have a significant impact on the cost of energy for configurations using WTGs because of the large investment required. For information purposes, the resulting cost of energy associated with an interest rate of 4.5% was included in the Figure 1 : Average Cost of Energy.

The level of penetration of wind energy in the energy pool at Cartwright is proportional to the number of WTG installed on site. This value represents the total amount of power produced by wind turbines over the project life divided by the total amount of power used.

The results for average cost of energy and wind penetration over the expected project life of 20 years are shown in the figure below. From this figure, it can clearly be seen that there are

configurations using either WTG model that produce a COE lower than the base case. However, the EWT900 results in a much lower overall cost of energy and a much higher wind penetration level than the NPS100. The design methodology leading to these results was provided in Section 3.

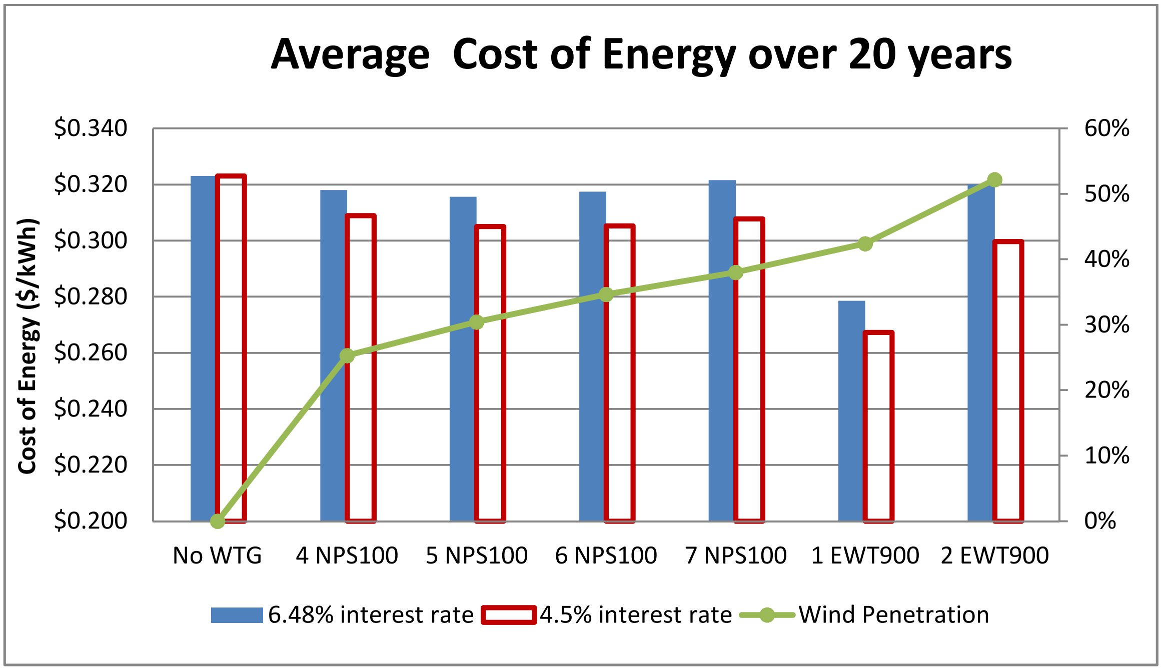

Figure 1 : Average Cost of Energy

4.5 Evolution of Cost of Energy

Figure 2 : Evolution of Cost of Energy shows the evolution of the non-discounted cost of power over the 20 years of the project life. It illustrates that the inclusion of more WTGs or larger WTGs in the energy mix reduces the impact of rising fuel costs on the average cost of energy over the project life. The graph also indicates that scenarios with the EWT900 turbine result in much lower energy costs. Scenarios with the NPS100 also result in a lower energy cost than the base case, but the cost is significantly higher than the results with the EWT900.

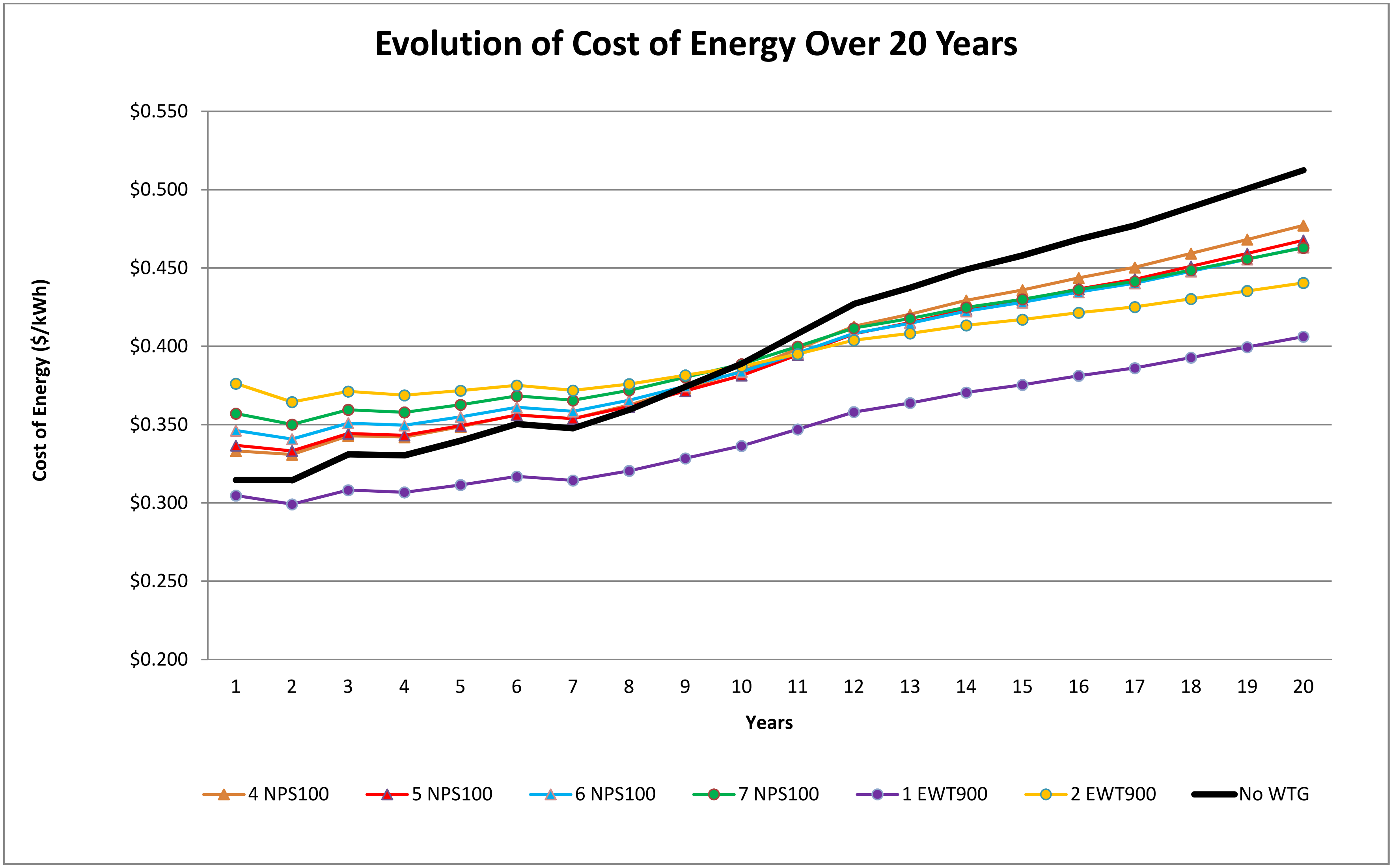

Figure 2 : Evolution of Cost of Energy

4.6 Fuel Costs and Excess Wind Energy

The average yearly fuel costs provide a good indication of the system reliance on fossil fuels for operation. The greater the installed wind capacity, the lower the annual fuel costs. However because of the magnitude and variability of electrical load on site, above a certain quantity of turbines, not all the energy produced by the turbines can be used by the system, causing the WTG to be less efficient.

The following figure shows the average yearly fuel costs for each configuration as well as the associated percentage fuel saved. The percentage of wasted WTG energy is also shown.

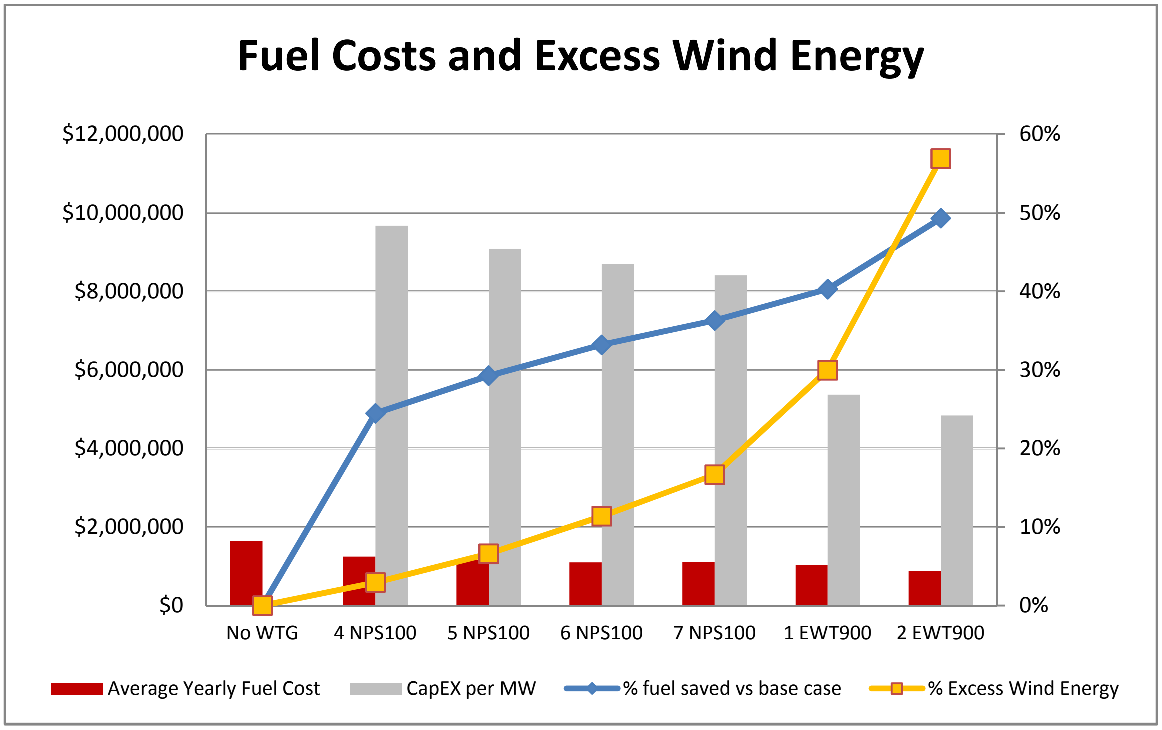

Figure 3 : Fuel Costs and Excess Wind Energy

4.7 Avoided Greenhouse Gas Emissions

The addition of renewable energy to the Cartwright electrical grid would have an impact on the amount of Greenhouse Gas (GHG) emissions resulting from energy production. NLH specified that it uses a value of 2.791 kg of CO_2 for each liter of diesel burned in the gensets it operates. Based on this number, Hatch calculated that the amount of avoided GHG emissions for each project configuration is as follows:

Case	Avoided Emissions of CO_2 (tonnes) over 1 Year	Avoided Emissions of CO_2 (tonnes) over 20 years
No WTG	0	0
4 NPS100	868	17,366
5 NPS100	1,038	20,766
6 NPS100	1,177	23,548
7 NPS100	1,287	25,746
1 EWT900	1,429	28,586
2 EWT900	1,749	34,988

Table 7 : Avoided Emissions of CO_2

Note: As of 2010, total Newfoundland and Labrador Green house gas emissions were 8.9 million tonnes per year, so 0.016 % of total Provincial emissions would be avoided by the installation of 1 EWT900 WTG at Cartwright.

4.8 Qualitative Comparison of WTG Models

The results presented in Section 4.1 clearly highlight the difference in wind penetration and energy cost between the two turbines being considered. The NPS100 is a small wind turbine that is easier to deploy yet has limited control capabilities, while the EWT900 is a full-size turbine with a large rotor diameter and the full control package associated with a utility scale turbine. Both turbines have an excellent track record in arctic conditions, making both potential candidates for the application. On the economic aspect, though the cost estimates will need to be validated in the next phase of the project, the cost per installed kW is much lower for the larger turbine which is generally common within the wind industry. Consequently, the energy produced comes at a lower price for the EWT900 than the NPS100. On the electrical side, the EWT is oversized for the application and produces much more energy than the NPS. Accordingly, the amount of excess energy by the EWT WTG is far above the NPS model, however the overall cost of useful energy remains lower for the EWT. The excess energy is expected to be easier to manage on the EWT as well, since it has active curtailment and derating management capabilities. From an environmental perspective, the EWT allows for more avoided emissions than the NPS. The practical O&M aspect also favors the EWT, as the manufacturer offers O&M options through long term contracts and, under certain circumstances, will even offer an availability warranty.

The size of the EWT900 makes for a more complex deployment, construction and installation. The logistical capabilities, including the remoteness, of the Cartwright port and community are not well documented and may make the delivery, unloading, transport and installation of the

EWT turbine much more expensive than budgeted at present. This could be a fatal flaw associated with the EWT900 WTG. A full logistic analysis is strongly recommended to confirm whether the installation of the EWT900 WTG is feasible. It needs to be noted that turbine models between 100 KW to 900 KW are not commonly available from many OEMs especially for use in arctic conditions. A more detailed turbine selection process should be initiated in following phases of the project.

The table below shows a comparison between the two models with “X” indicating superiority in each category:

Category	NPS100	EWT900
Track Record	X	X
Turbine Cost		X
Energy Poduction		X
Control Capabilities		X
Avoided Emissions		X
O&M		X
Logistics	X	

Table 8 : WTG qualitative comparison

Figure 4 : Turbines Sizehighlights the size differences between the NPS100 and the EWT900.

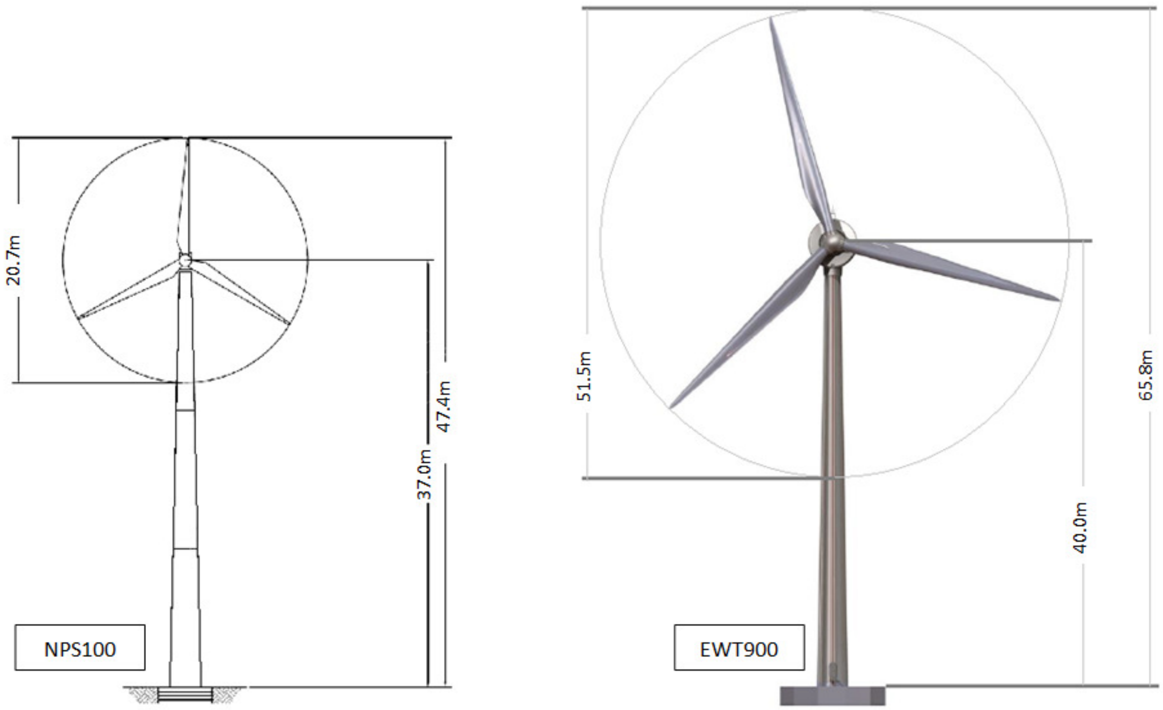

Figure 4 : Turbines Size

5. Conclusion and Recommendations

Based on the system modeling and preliminary economic analysis performed by Hatch, the optimal system design for Cartwright is the installation of one EWT900 WTGs. This result is based on the anticipated energy production of the existing gensets and the future wind turbines, according to the functional specifications of the local grid as provided by NLH. It should be noted that several components were excluded from this analysis, including the value of avoided GHG emissions, the level of community acceptance and government policy implications. It is recommended that NLH gather more information on these topics prior to moving forward with further assessments of project viability.

It is important to note that a detailed mechanical and electrical stability study was not performed at this stage. It is critical that such a study be performed in advance of the detailed design stage to determine the impacts of adding WTGs to the existing system, as well as the actual limitations of the current grid. Furthermore, a logistics analysis needs to be completed to determine whether the local capabilities allow for the installation of the EWT900 turbine.

ELB

Attachment(s)/Enclosure :

Annex 1 - Construction Costs.pdf

H340923-0000-05-124-0005_rev2.pdf (Cartwright Final Wind Resource Assessment Report)

Annex 1 – Construction Costs Used in HOMER Model

Costs to add turbines at various sites	NPS100	EWT900
WTG O&M ($/y)	$ 20,000	$ 60,000
Project development (lump sum)	$ 200,000	$ 200,000
Engineering and studies (lump sum)	$ 175,000	$ 175,000
Deployment cost (lump sum)	$ 75,000	$ 175,000
New electrical line ($/km)	$ 250,000	$ 250,000
New road ($/km)	$ 300,000	$ 300,000
Interconnection to local grid	$ 50,000	$ 50,000
Rock blasting (per turbine)	$ 20,000	$ 250,000
Concrete batch plant deployment	$ 25,000	$ 25,000
Foundation concrete content (cubic yards)	29.09	250.00
Concrete cost ($/cubic yard)	$ 900	$ 900
Other foundation material and labor	$ 25,000	$ 125,000
Total foundation cost (per turbine)	$ 71,180	$ 600,000
Turbine purchase cost (per turbine)	$ 325,000	$ 2,000,000
Extra turbine cost for arctic version (per turbine)	$ 20,000	$ -
Turbine transportation to site (per turbine)	$ 45,000	$ 250,000
Turbine installation (per turbine)	$ 50,000	$ 125,000
Turbine peak power output (kW)	100	900
Project management (% of total project cost	10%	10%
Construction management (% of construction costs)	6%	6%
Contingency for turbine components	5%	5%
Contingency for construction costs	10%	10%

Appendix J: Hybrid system modelling and optimisation report – L’Anse au Loup

Project Report

November 9, 2015

Coastal Labrador Wind Monitoring Program

L'Anse au Loup Hybrid System Modeling and Optimization

Distribution

Trevor Andrew – NLH
Asim Haldar – NLH
Bob Moulton – NLH
Timothy Manning – NLH
Terry Gardiner – NLH
Louis Auger – Hatch
Dany Awad – Hatch
Ève-Line Brouillard - Hatch

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1. Introduction, Objectives and Scope of Work

As part of the project titled, Coastal Labrador Wind Monitoring Program, Newfoundland and Labrador Hydro (NLH) mandated Hatch to complete a wind monitoring campaign to determine the feasibility of adding Wind Turbine Generators (WTG) to Labrador isolated communities of Nain, Hopedale, Makkovik, Cartwright and L'Anse au Loup. This report presents the methodology and results related to L'Anse au Loup.

The wind monitoring periods are listed in the table below and additional information on the wind monitoring campaigns can be found in the respective WRA reports completed for each community.

	Date of first data recorded	Date of last data recorded
Nain (mast 2601)	30 October 2013	19 July 2015
Hopedale (mast 2602)	27 October 2013	19 July 2015
Makkovik (mast 2603)	25 October 2013	19 July 2015
Cartwright (mast 2605)	5 November 2013	13 July 2015
L'Anse au Loup (mast 2604)	5 October 2013	27 April 2015

Table 1 : Sites and Monitoring Periods

The specific objectives of the mandate were to provide the potential wind turbine capacity that can be installed on these 5 communities, the potential wind penetration and the associated cost breakdown for development, construction and operations (CapEx and OpEx).

2. Overview of Existing Diesel Grid on Site

L'Anse au Loup has an electrical demand quite large compared to other communities being evaluated under this mandate. The electrical equipment on site as well as electrical load and future forecast are defined below, based on the information provided by NLH.

2.1 Installed Power Generation Equipment

The power grid operated by NLH in L'Anse au Loup currently relies on two different sources of power. Firstly, this community is interconnected to the Hydro-Quebec (HQ) grid, which currently provides over 90% of the electricity being used. The remaining power is being supplied by six (6) diesel generators (gensets). It is important to note that based on information provided by NLH the maximum grid intertie with Hydro Quebec is limited to 4 MW.

The gensets currently on site supply less than 10% of the electrical demand and include the following units:

Unit Number	Unit kW	Brand	Model	RPMs	Purchase Year
(G1)2005	800	CAT	D-3512	1800	1988
(G2)2012	1100	CAT	3516	1800	1984
(G3)2041	1000	CAT	D-3512	1800	1971
(G4)246	600	CAT	D-398	1200	1975

Unit Number	Unit kW	Brand	Model	RPMs	Purchase Year
(G5)2091	1825	CAT	B-3516	1800	2015
(G6)2082	1825	CAT	B-3516	1800	2009

Table 2 : Diesel Gensets on Site

2.2 Generator Control Scheme

The gensets on site are managed by an automated control scheme. NLH explained that the control logic, aims to minimize the number and size of the gensets running at any given time while also insuring sufficient spinning reserve to meet increases in load. To do so, whenever the unit running is operating at less than 75% load ratio, the system switches to a smaller unit, if available. Whenever the unit running is loaded at more than 85%, the system switches to a larger unit, if available, or starts a second generator to share the load. The minimum load ratio for all gensets operated by NLH is 30%.

Because of the specificity of L'Anse au Loup, prior to modelling and optimizing, NLH indicated that the specific case of L'Anse au Loup should be modelled without any minimum load for the gensets, while the Hydro-Quebec grid should provide at least 30% of the energy demand.

2.3 Electric Load

The electric load at L'Anse au Loup varies significantly between winter and summer months. NLH provided the 2014 monthly average hourly electrical load. This data is shown in the table below:

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
L'Anse au Loup	4,202	4,167	3,532	2,822	2,384	2,482	1,905	2,039	2,032	2,140	3,492	4,311

Table 3 : Average Load (kW)

The electrical production from the diesel plant and the supply from Hydro-Quebec was monitored on a 10 minute timestamp. The data recorded, which covers the period of January 2014 to January 2015, was made available for inclusion in the model. This dataset provided the basis of calculation for the production of a daily hourly load profile, an essential component of the modeling exercise.

2.4 Forecasted Load and Energy Price

NLH provided information showing anticipated growth of peak hourly power demand and total yearly energy for the years 2015 to 2033 for L'Anse au Loup. The expected average fuel cost for each year was also supplied for the same period. The equation used to determined the price of the electricity delivered by Hydro-Quebec was made available by NLH. This price has been calculated accordingly for each year of the project life. The table below summarizes these information.

L'Anse au Loup	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033
Gross Peak (kW)	6,396	6,456	6,281	6,324	6,365	6,402	6,435	6,465	6,494	6,519	6,541	6,560	6,579	6,601	6,620	6,635	6,650	6,666	6,681
Net Peak (kW)	6,276	6,336	6,161	6,204	6,245	6,282	6,315	6,345	6,374	6,399	6,421	6,440	6,459	6,481	6,500	6,515	6,530	6,546	6,561
Gross Energy (MWh)	27,379	27,903	27,147	27,336	27,511	27,671	27,812	27,945	28,069	28,178	28,273	28,355	28,438	28,533	28,613	28,679	28,745	28,812	28,878
Net Energy (MWh)	26,919	27,443	26,687	26,876	27,051	27,211	27,352	27,485	27,609	27,718	27,813	27,895	27,978	28,073	28,153	28,219	28,285	28,352	28,418
Diesel Price ($Cdn/Litre)	$0.84	$0.91	$0.91	$0.94	$0.98	$0.97	$1.01	$1.06	$1.11	$1.18	$1.24	$1.28	$1.32	$1.35	$1.38	$1.41	$1.45	$1.49	$1.53
HQ grid ($/kWh)	$0.11	$0.12	$0.12	$0.12	$0.13	$0.13	$0.13	$0.14	$0.15	$0.16	$0.17	$0.17	$0.18	$0.18	$0.19	$0.19	$0.20	$0.20	$0.21

Table 4 : Forecasted load, and price growth of fuel and electricity (2015-2033)

The forecasted load growth and energy price increase (fuel and electricity) were important components in the evaluation of the various available system configurations as the objective was to find the most desirable system over the life of the project.

3. Design Methodology

3.1 Software Used

The electrical system and integration of the wind turbines was modelled and simulated using HOMER (Hybrid Optimization of Multiple Electric Renewables). This software is specifically used to model and optimize the configuration of micro-grid systems composed of multiple components, which can include wind turbine generators, photovoltaic solar panels, hydroelectric generators, batteries as well as generators running on various types of fuel. Using inputs comprising electric load profile, electrical architecture of the system (DC vs AC, etc.), renewable resources as well as costs for the purchase, operation and replacement of each component, HOMER can investigate multiple configurations and produce insight as to how to minimize the Levelized Cost of Energy (LCOE) or fuel used by the system. In the context of the current assignment, the outputs of the software were integrated in MS Excel spreadsheets to include electrical load, fuel cost and HQ price variations over time with the aim of selecting the most efficient solution over the life of the project. Due to the restriction of HOMER to properly integrate and model utility supply generation, the HQ supply electricity was simulated as four gensets of 1000kW each.

3.2 Model Building

NLH provided valuable information related to the historical operating performance of the existing system. The data provided included operations and maintenance (O&M) costs and overhaul costs, as well as data linking electrical production and fuel consumption. Each genset model was created in HOMER to accurately reflect these parameters, as well as the specific fuel curve provided by NLH. The Hydro-Quebec grid was also represented in HOMER and simulated as four 1000kW gensets, due to the HOMER restrictions as identified in section 3.1.

The average monthly electrical load provided by NLH was used as the basis for the load profile included in the model. The 10 minute electrical supply dataset, covering a year period, was used to establish a daily electric production profile. The assumption was made that the electric production at any given time was equal to the electric demand, so the daily load profile would be the same as the daily production profile. This daily load profile proved to be similar in shape for all 12 months of data provided, with differing magnitudes across months. As such, the assumption was made that the typical daily load profile shape would be the same for all 12 months but that it would be scaled to reflect the monthly averages provided by NLH. This daily load profile for each month was integrated as the electric load for the project. HOMER uses the base hourly profile and introduces hour to hour and day to day random variations based on parameters defined by the user. The result is a random time series for the load that has a pattern similar to the actual load.

At this point, an iteration of the model was run in HOMER in a configuration representing the equipment present on site. This iteration is the base case to which the other iterations, which use wind turbines, are compared in regards to fuel savings and energy cost.

It should be noted that according to the specifications provided by NLH for L'Anse au Loup (i.e. no minimum load for the gensets and a minimum of 30% of the load covered by the HQ grid) the base case system modelled does not produce energy from diesel as much as reported and forecasted by NLH. HOMER models that only 3% of the energy would be produced by the diesel gensets, instead of around 7% as per the NLH forecast. This difference is due to NLH having to produce more energy from the diesel generators during the periods where HQ is undergoing maintenance on their grid (which are not modelled in Homer).

A preliminary turbine selection for the L'Anse au Loup project was completed as part of the Wind Resource assessment phase. Given the major load at L'Anse au Loup, and considering the potential benefit of a bigger wind turbine, only one of the WTGs, identified as potentially interesting for the hybrid projects in Labrador communities, was selected for modelling at L'Anse au Loup; additional information on the turbine selection methodology is available in the WRA report. The turbine is the Emergya Wind Technologies 900kW (EWT900). This WTG was modeled in HOMER based on manufacturer provided specifications. The long term wind resource calculated in the wind resource assessment campaign was integrated in the model and the energy production predicted by the software WindFarmer was compared with the energy calculated by HOMER. WindFarmer is routinely used to optimize wind farm layouts with regard to energy, topography and restrictions and to estimate the energy production. WindFarmer outputs are considered more accurate than HOMER for this aspect. Following some minor model adjustments, the comparison showed that the HOMER results were similar to the WindFarmer results within a few percent, confirming that the simulation used realistic wind energy production numbers.

The following assumptions were made during the optimization process and in the simulation phase:

- The daily load profile was derived from time series and historical values provided by NLH
- Fuel costs, electricity prices and load growth were based on information provided by NLH, as presented in Section 2.4
- An inflation rate of 2.21% and average NLH long term marginal cost of debt (rounded) of 6.48% were used, according to historical values specified by NLH
- Construction costs have been defined based on information from manufacturers and historical values from past projects

3.3 System Sizing and Optimization

The sizing and optimisation of the proposed wind project for L'Anse au Loup was determined through an iterative process. HOMER simulations were run using varying numbers of WTG model selected in the previous phase. The objective of the iterations was to determine the number of WTGs that would result in the lowest calculated cost of energy (COE).

The outputs from Homer were integrated in Excel spreadsheets to evaluate the impact of increasing fuel costs, electrical demand, inflation and cost of borrowed capital. Some key metrics were identified to compare the various configurations and determine the most economically viable scenarios. The results are presented in the following section.

4. Results

4.1 Proposed Configuration

Based on the modeling performed in HOMER and based on the cost of energy as the main criteria, there is no optimal number of turbines for integration in the L'Anse au Loup system. Each configuration tested has a higher cost of energy than the base case system consisting of the diesel gensets and the HQ grid. This is mainly due to the low cost of the energy provided by HQ. The table below shows a summary of the results for integration of various numbers of WTG.

	Fuel saved vs base case	Yearly Fuel Savings	Wind Penetration	WTG energy over 20 yrs (kWh)	Excess energy over 20 yrs (kWh)	Cost of Energy ($/kWh)
No WTG	0%	$0	0%	0	0	$0.130
1 EWT900	20.5%	$483,928	10.6%	58,253,120	3	$0.133
2 EWT900	49.1%	$983,197	21.1%	116,506,240	102,145	$0.132
3 EWT900	60.7%	$1,417,467	30.7%	174,758,920	5,227,505	$0.132
4 EWT900	67.2%	$1,620,894	38.6%	233,012,480	19,964,417	$0.135
5 EWT900	71.5%	$1,906,305	44.7%	291,262,860	44,645,138	$0.134
6 EWT900	74.9%	$2,108,707	49.0%	349,517,840	79,275,475	$0.141

Table 5 : Summary of Results

The estimated energy production of each proposed configuration accounts for the possible losses in a wind farm, such as wake, aerodynamic, electrical, operational and power curve losses. The figures of availability should be defined with more accuracy at the detailed turbine selection stage, based on statistics for the turbine selected and after confirmation of the O & M strategy and review of the draft O&M contract if applicable. Based on preliminary manufacturer's discussions, other factors that will need to be considered for availability include the benefit of having a greater number of turbine units due to potential difficulties to execute repairs in the winter months. This will need to be analyzed as part of the turbine selection process.

As noted in Sections 4.2 and 4.3, the cost of energy does not include all applicable costs. Additional costs not reflected include mechanical and electrical stability studies, system integration costs, control and communications system costs, as well as detailed logistic studies, plant detailed design and optimization. On the other hand, given the accessibility of this community, savings could be made for some costs categories compared to the other communities, but that was not considered in the present assessment.

4.2 Construction Costs

The total estimated cost of building a wind farm at L'Anse au Loup includes development, turbine, construction and project management. Project contingency was also included, at 5% for WTG components and 10% for construction costs. Additional integration and pre-development costs include logistics study, integration study, electrical and mechanical stability studies have not been included. System integration costs have also been left out of the equation, as well as any associated integration and communication equipment costs since this scope were not included in the present project. Each of the hybrid projects in Labrador communities has been assessed independently, however there may be benefits from economies of scale if more than one project is retained (e.g. for purchasing the turbines, or renting a crane).

For example, for L'Anse au Loup, assuming economies due to more than one project moving forward and considering a 5% savings on the WTGs price and a reduction of 10% on the construction costs, the cost of energy produced by a hybrid system configured with 3 wind turbines would be the same as without wind turbine using mainly the HQ grid.

All of the aforementioned studies would need to be completed to fully assess the viability of the project. The following table shows a summary of the included project costs for various iterations:

	EWT 900					
Number of units	**1**	**2**	**3**	**4**	**5**	**6**
Development costs	$375,000	$375,000	$375,000	$375,000	$375,000	$375,000
Turbine costs	$2,375,000	$4,750,000	$7,125,000	$9,500,000	$11,875,000	$14,250,000
Construction costs	$1,868,250	$2,708,300	$3,548,350	$4,388,400	$5,228,450	$6,068,500
Project management	$461,825	$783,330	$1,104,835	$1,426,340	$1,747,845	$2,069,350
Contingency	$389,258	$624,163	$859,069	$1,093,974	$1,328,880	$1,563,785
Total project CapEx:	**$5,469,333**	**$9,240,793**	**$13,012,254**	**$16,783,714**	**$20,555,175**	**$24,326,635**
CapEx per installed MW:	$6,077,036	$5,133,774	$4,819,353	$4,662,143	$4,567,817	$4,504,932

Table 6 : Summary of Construction Costs

For the detailed construction costs see Annex 1.

4.3 Further Study Required – System Integration

The installation of WTGs on the grid at L'Anse au Loup will require further electrical and mechanical studies, which are not part of the current scope of work and should be performed at a later stage to fully assess the project viability. The results of these studies will determine whether additional control and communication equipment needs to be added to the system. It should be noted that since it is not currently known if any additional equipment will be required, no cost was included for such components in any of the simulations at this stage. The energy costs presented in the following section include no allocation for additional control and communication equipment.

4.4 Penetration and Energy Cost

The cost of energy for each option is calculated based on the total cost of producing the required quantity of energy during the life of the project and the total amount of energy produced. Costs are based on the cost of borrowed capital for CapEx, increasing fuel costs and energy demand as well as anticipated discount rate (inflation) over the duration of the project. All costs presented in this report are based on the average long term marginal cost of debt of 6.48% provided by NLH. However this historical value may not be representative of future interest rates and a different value could have a significant impact on the cost of energy for configurations using WTGs because of the large investment required. For information purposes, the resulting cost of energy associated with an interest rate of 4.5% was included in the Figure 1 : Average Cost of Energy.

The level of penetration of wind energy in the energy pool at L'Anse au Loup is proportional to the number of WTG installed on site. This value represents the total amount of power produced by wind turbines over the project life divided by the total amount of power used.

The results for average cost of energy and wind penetration over the expected project life of 20 years are shown in the figure below. From this figure, it can clearly be seen that there are configurations that produce a COE lower than the base case, but this is true only with an interest rate of 4.5%. The design methodology leading to these results was provided in Section 3.

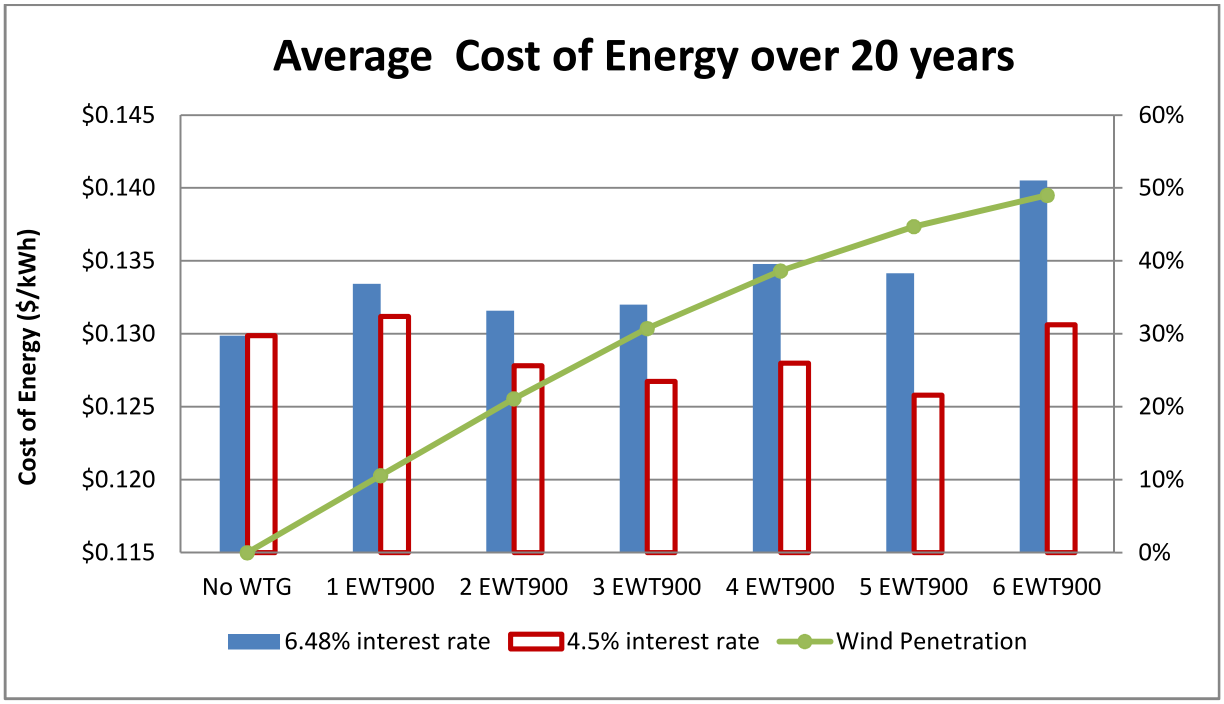

Figure 1 : Average Cost of Energy

4.5 Evolution of Cost of Energy

Figure 2 : Evolution of Cost of Energy shows the evolution of the non-discounted cost of power over the 20 years of the project life. It illustrates that the inclusion of more WTGs in the energy mix reduces the impact of rising fuel costs on the average cost of energy over the project life.

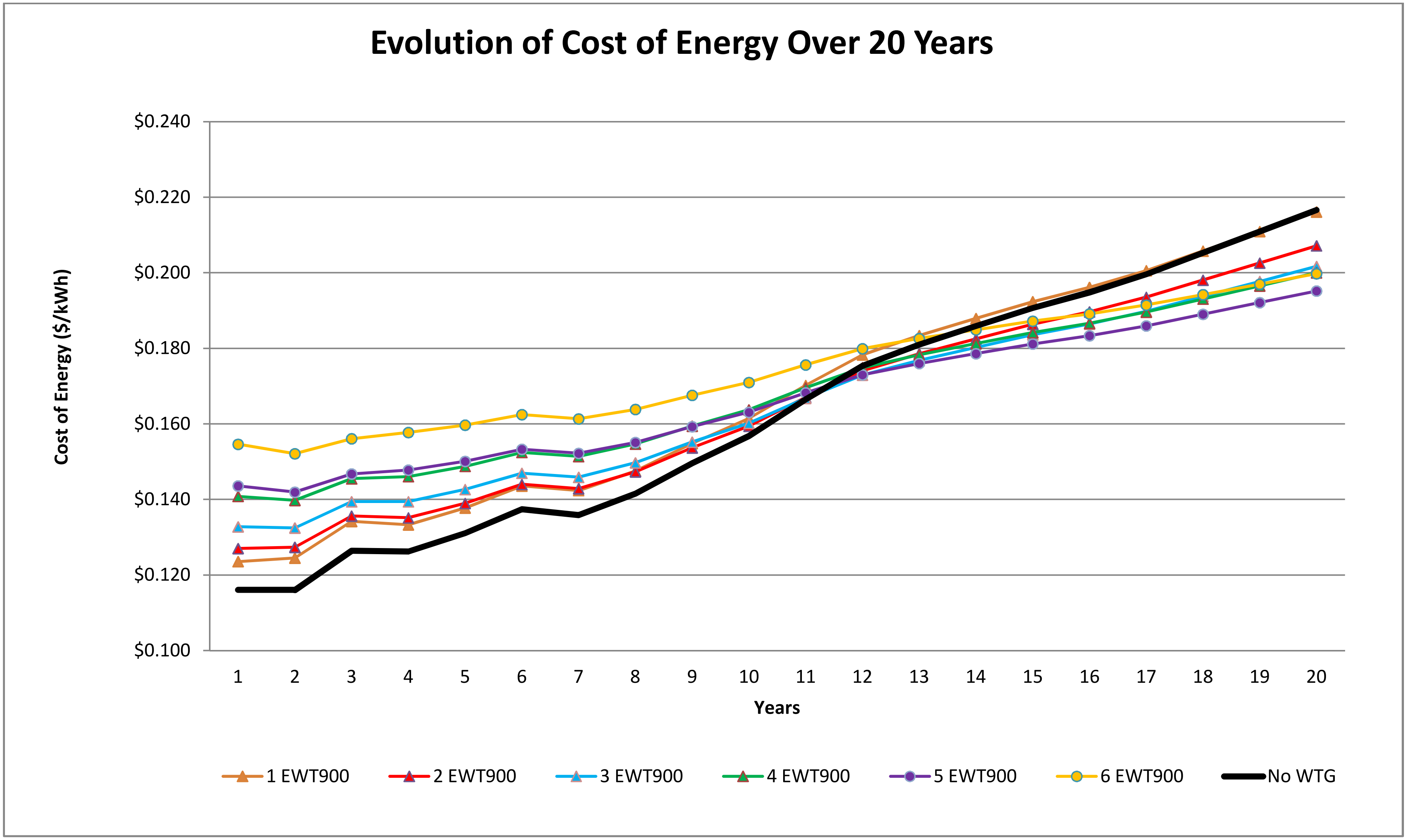

Figure 2 : Evolution of Cost of Energy

4.6 Energy Costs and Excess Wind Energy

The average yearly energy costs provide a good indication of the system reliance on fossil fuels and HQ grid for operation. The greater the installed wind capacity, the lower the annual energy costs. However because of the magnitude and variability of electrical load on site, above a certain quantity of turbines, not all the energy produced by the turbines can be used by the system, causing the WTG to be less efficient.

The following figure shows the average yearly fuel costs for each configuration as well as the associated percentage fuel saved. The percentage of wasted WTG energy is also shown.

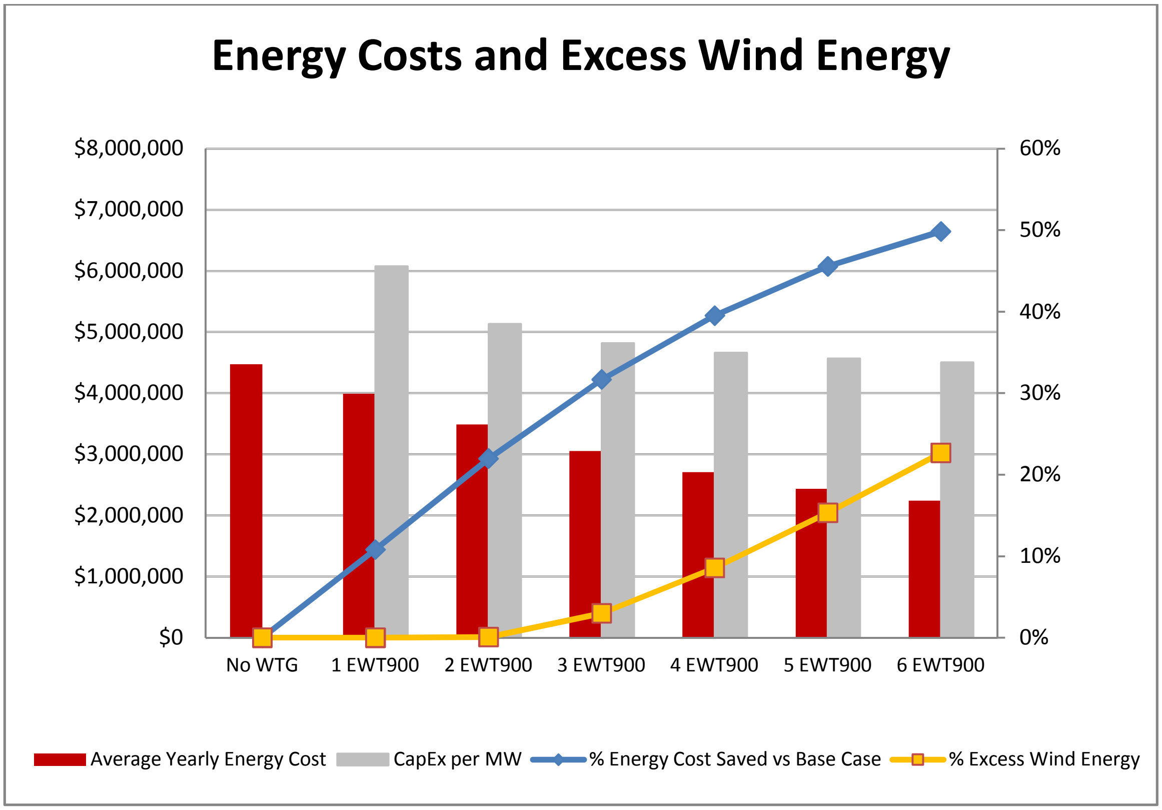

Figure 3 : Energy Costs and Excess Wind Energy

4.7 Avoided Greenhouse Gas Emissions

The addition of renewable energy to the L'Anse au Loup electrical grid would have an impact on the amount of Greenhouse Gas (GHG) emissions resulting from diesel energy production, but not as much as for the other communities, since most of the energy demand is met by the HQ grid. NLH specified that it uses a value of 2.791 kg of CO_2 for each liter of diesel burned in the gensets it operates. Based on this number, Hatch calculated that the amount of avoided GHG emissions for each project configuration is as follows:

Case	Avoided Emissions of CO_2 (tonnes) over 1 Year	Avoided Emissions of CO_2 (tonnes) over 20 years
No WTG	0	0
1 EWT900	144	2,885
2 EWT900	346	6,911
3 EWT900	428	8,553
4 EWT900	473	9,466
5 EWT900	504	10,074
6 EWT900	527	10,549

Table 7 : Avoided Emissions of CO_2

Note: As of 2010, total Newfoundland and Labrador Green house gas emissions were 8.9 million tonnes per year. However, since the system configuration modelled for L'Anse au Loup rely on the diesel gensets only for 3% of the energy demand, only 0.005 % of total Provincial emissions would be avoided by the installation of 3 EWT900 WTG at L'Anse au Loup.

4.8 Qualitative Appreciation of WTG Model

The EWT900 is a full-size turbine with a large rotor diameter and the full control package associated with a utility scale turbine. This turbine has an excellent track record in arctic conditions, making it a potential candidate for the application. On the economic aspect, though the cost estimates will need to be validated in the next phase of the project, the cost per installed kW is much lower for larger turbines which is generally common within the wind industry. Consequently, the energy produced comes at a lower price for the EWT900 than it would be with a smaller wind turbine. The excess energy is expected to be easy to manage on the EWT, since it has active curtailment and derating management capabilities. The EWT has also a practical O&M aspect, as the manufacturer offers O&M options through long term contracts and, under certain circumstances, will even offer an availability warranty.

Compared to smaller wind turbines, the size of the EWT900 makes for a more complex deployment, construction and installation. However, since L'Anse au Loup is not as remote as some other Labrador communities, and since it seems to have good logistical capabilities, the delivery, unloading, transport and installation of the EWT turbine might not be much more expensive than budgeted at present. A full logistic analysis is, though, strongly recommended to confirm whether the installation of the EWT900 WTG is feasible. It needs to be noted that turbine models between 100 KW to 900 KW are not commonly available from many manufacturers especially for use in arctic conditions. A more detailed turbine selection process should be initiated in following phases of the project.

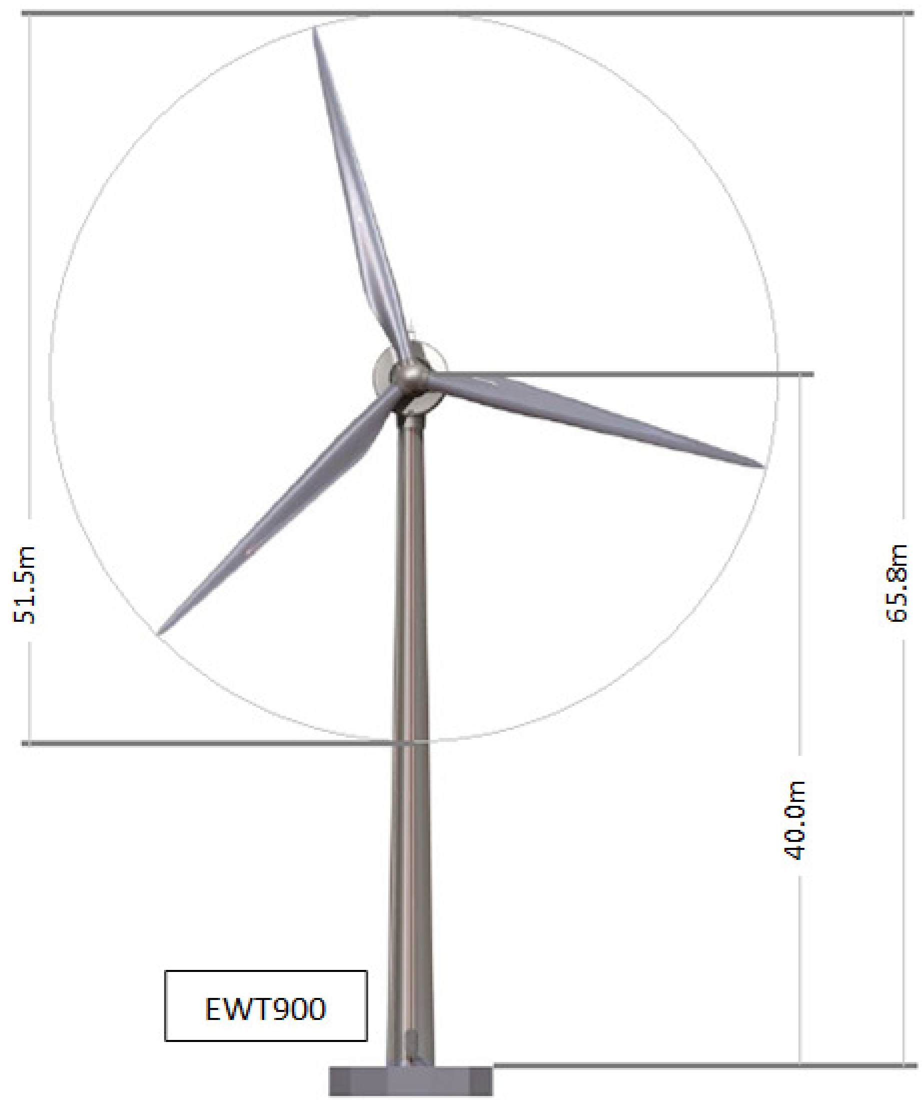

Figure 4 : Turbine Size

5. Conclusion and Recommendations

Based on the system modeling and preliminary economic analysis performed by Hatch, the optimal system design for L'Anse au Loup is to maximize the use of electricity provided by the Hydro-Quebec grid. None of the tested configurations, integrating wind turbines in the system, was economically competitive with the base case system consisting of the diesel gensets and the HQ grid. This is mainly due to the low cost of the energy provided by HQ.

This result is based on the anticipated energy production of the existing gensets, HQ grid and the future wind turbines, according to the functional specifications of the local grid as provided by NLH. It should be noted that several components were excluded from this analysis, including the value of avoided GHG emissions, the level of community acceptance and government policy implications. Each of the hybrid projects in Labrador communities has been assessed independently, however they might benefit from economies of scale if more than one project is retained. In addition, given the accessibility of this community, savings could be made for some costs categories compared to the other communities. A more detailed cost analysis might conclude to an economically competitive hybrid project in L'Anse au Loup. It is recommended that NLH gathers more information on these topics prior to exclude this community for a potential hybrid energy project.

It is important to note that a detailed mechanical and electrical stability study was not performed at this stage. It is critical that such a study be performed in advance of the detailed design stage to determine the impacts of adding WTGs to the existing system, as well as the actual limitations of the current grid. Furthermore, a logistics analysis needs to be completed to determine whether the local capabilities allow for the installation of the EWT900 turbine.

ELB

Attachment(s)/Enclosure :

Annex 1 - Construction Costs.pdf

H340923-0000-05-124-0004_rev2.pdf (L'Anse au Loup Final Wind Resource Assessment Report)

Annex 1 – Construction Costs Used in HOMER Model

Costs to add turbines at various sites	NPS100	EWT900
WTG O&M ($/y)	$ 20,000	$ 60,000
Project development (lump sum)	$ 200,000	$ 200,000
Engineering and studies (lump sum)	$ 175,000	$ 175,000
Deployment cost (lump sum)	$ 75,000	$ 175,000
New electrical line ($/km)	$ 250,000	$ 250,000
New road ($/km)	$ 300,000	$ 300,000
Interconnection to local grid	$ 50,000	$ 50,000
Rock blasting (per turbine)	$ 20,000	$ 250,000
Concrete batch plant deployment	$ 25,000	$ 25,000
Foundation concrete content (cubic yards)	29.09	250.00
Concrete cost ($/cubic yard)	$ 900	$ 900
Other foundation material and labor	$ 25,000	$ 125,000
Total foundation cost (per turbine)	$ 71,180	$ 600,000
Turbine purchase cost (per turbine)	$ 325,000	$ 2,000,000
Extra turbine cost for arctic version (per turbine)	$ 20,000	$ -
Turbine transportation to site (per turbine)	$ 45,000	$ 250,000
Turbine installation (per turbine)	$ 50,000	$ 125,000
Turbine peak power output (kW)	100	900
Project management (% of total project cost	10%	10%
Construction management (% of construction costs)	6%	6%
Contingency for turbine components	5%	5%
Contingency for construction costs	10%	10%

NL Hydro
Labrador Interconnection Options Study
H362861

Engineering Report
Engineering Management
Final Report

Labrador Interconnection Options Study

Final Report

H-362861-00000-200-066-0001

2020-11-10	0	Approved for Use	J. Zuliani, D. Anders, M. Ali	D. Kell	M. Carreau	R. Collett, J. Flynn
DATE	REV.	STATUS	PREPARED BY	CHECKED BY	APPROVED BY	APPROVED BY
				Discipline Lead	Functional Manager	Client

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Appendix A **Capital Cost Estimate Memo**

Appendix B **Single Line Diagrams**

Appendix C Power Flow Study Results

Appendix D Capital Cost Estimate Details

1. Executive Summary

Newfoundland and Labrador Hydro (NL Hydro) is responsible for electricity supply to remote communities in the Labrador region. Currently, NL Hydro owns and operates diesel gensets in each community along with a local distribution grid to supply electricity to the customers within each community.

NL Hydro is exploring options to reduce diesel fuel consumption. This study assessed the following seven (7) different Options at a preliminary level to achieve this goal. The Options are:

- **Option 1:** Fully interconnected system as outlined in original NL Hydro study. Northern Communities are connected on a 138-kV loop and Southern Communities are connected on a 69-kV radial line. 100% of the electricity needs will be served by Churchill Falls or Muskrat Falls.
- **Option 2:** Fully interconnected system. Northern Communities are connected on two parallel 138 kV radial lines running from Happy Valley Terminal Station, drawing electricity from Muskrat Falls and Churchill Falls, to Voisey's Bay and Southern Communities are connected on a 69-kV radial line. 100% of the electricity needs will be served by Churchill Falls or Muskrat Falls.
- **Option 3:** Fully interconnected system. Northern Communities are connected on a single 138 kV radial line running from Happy Valley Terminal Station, drawing electricity from Muskrat Falls and Churchill Falls, to Voisey's Bay and Southern Communities are connected on a 69-kV radial line. 100% of the electricity needs will be served by Churchill Falls or Muskrat Falls.
- **Option 4:** Large microgrid system. Renewable generation is located in the North at Voisey's Bay. A radial line supplies electricity to the communities from Voisey's Bay. Some communities may not be connected due to the cost associated with the long transmission line. Voltage selection will be kept the same with 138 kV serving the north and 69 kV serving the south. It is assumed that 40-50% of the electricity generation (on a MWh basis) will be supplied by renewable sources.
- **Option 5:** Two microgrids. The Northern Communities will be served by a 138-kV radial transmission line connected to centralized renewable generation at Voisey's Bay. The Southern Communities will be served by a 69-kV radial system. The generation will be centralized, located at Port Hope Simpson or Cartwright. It is assumed that 40-50% of the electricity generation (on a MWh basis) will be supplied by renewable sources.

- **Option 6:** Isolated microgrids. Each community will be served by its own renewable generation and microgrid. It is assumed that 40-50% of the electricity generation (on a MWh basis) will be supplied by renewable sources.
- **Option 7:** Optimized isolated microgrids. Several communities will be connected together based on optimized designs with centralized generation centers. Design is optimized based on transmission line cost. It is assumed that 40-50% of the electricity generation (on a MWh basis) will be supplied by renewable sources.

1.1 Technical Assessment

Hatch assessed the shortlisted Options at a preliminary level and perform load flow studies on the highly interconnected option i.e. Options 1-5. The following objectives have been identified to assesses the proposed transmission options:

- Determine if the proposed Option will perform within the acceptable system limits. The criteria used during steady state analysis include thermal performance of all transmission element, system voltage requirement, and system steady state following a N-1 contingency event.
- Estimate transmission technical losses for each Option.
- List out the major components that involve construction of each Option.
- Estimate the CAPEX and OPEX for each Option.

Detailed single line diagrams for Options 1-5 are presented in Appendix B.

1.1.1 Option 1 - 3

Option 1-3 each have a different configuration for the transmission system; however, all three Options involve connecting the communities via a long 138 kV radial or loop transmission network

In the North, three configurations are studied:

- a loop connecting Churchill Falls and Happy Valley Terminal to the communities on a 138-kV transmission network (Option 1)
- a parallel loop connecting the communities between Happy Valley Terminal and Voisey's Bay, using a 138-kV transmission network (Option 2)
- a radial line from Happy Valley Terminal to Voisey's Bay, connecting the communities, using a 138-kV transmission network (Option 3)

Due to the remoteness of the communities in the north, the substations were designed with 2 transformers that add redundancy in the event of an outage.

In the South, the communities are connected via 69 kV radial line from Muskrat Falls to L'Anse-au-Loop, tapped off at different points to feed the southern communities

Based on the preliminary studies, Options1 and 2 are technically feasible as the sub-system steady state voltages and power flows are within the acceptable limits. Option 3 may have some adverse impact on the voltages under some operating condition as the load flow results did not converge for one of the contingency cases considered. However, that concern could be mitigated by examining the reactive power compensation strategy. Nevertheless, all the three transmission Options required integration of reactive power compensation devices, specifically shunt reactors, to compensate the charging of long transmission lines.

The losses for Options 1-3 were relatively high considering the long connections from Churchill and Muskrat Falls. It is worth noting that optimizing existing controls for transformer taps and switched shunt elements could reduce line flows and hence minimize the transmission losses.

1.1.2 Option 4

Option 4 has Northern Labrador communities connected by a long 138 kV radial line from Voisey's Bay and the communities in the South are connected to the North via a long radial transmission line, at 69 kV. There are increased operating and maintenance costs, reliability and reactive power compensation challenges associated with Option 4 as it involves long radial transmission lines serving remote communities that have a relatively light load. The system performed within the acceptable limit after some adjustments which includes adding shunt reactors. A comprehensive analysis of integrated reactive power management is required to operate the system efficiently.

1.1.3 Option 5

Option 5 entails Northern Labrador communities connected by a 138-kV radial line with generation at Voisey's Bay. Additionally, the Southern communities connected in radial microgrid, with generation at Port Hope Simpson. The system performed within the acceptable limits from thermal and voltage performance point of view. Similar to the above Options, reactive power compensation was required to keep the voltages of the sub-system within the acceptable limits.

1.1.4 Generation Requirements

The generation requirements for each of the Options is presented in Table 1-1. For Option 1-3, it is assumed 100% of the electricity will be supplied by Churchill and Muskrat Falls hydropower. For Option 4-7, wind generation and energy storage were sized to provide approximately 50% of the annual energy generation.

For Option 4, which is connected to Voisey's Bay in the north, an energy storage system is not required since the generation at Voisey's Bay can be used to manage the variability of the wind generation. Similarly, for Option 5, the large microgrid in the north can also take advantage of connecting to Voisey's Bay to manage the variability of the wind generation.

Option 6 and 7 have the largest number of energy storage systems, since each microgrid will require generation and energy storage to manage the variability of the wind. Additionally, though the installed capacity of wind is lower (since L'Anse-au-Loop is not supplied), these options have the highest number of wind turbines since there are turbines to supply each community (or cluster). Smaller turbines are required to serve the smaller communities. Option 7 takes advantage of connecting the communities, in order to install fewer but large wind turbines instead of many 800 kW or 100 kW turbines.

In Option 6 and 7, L'Anse-au-Loop is not supplied by wind generation, since it is more economical to continue to serve the community with the hydropower from Hydro Quebec.

Table 1-1: Generation Requirements for Each of the Options

Option	Generation Requirements	Configuration
Option 1	Hydroelectric from Churchill and Muskrat Falls	N/A
Option 2	Hydroelectric from Churchill and Muskrat Falls	N/A
Option 3	Hydroelectric from Churchill and Muskrat Falls	N/A
Option 4	38.5 MW Wind	11 x 3.5 MW
Option 5	38.5 MW Wind, 3.5 MW Storage	Wind: 11 x 3.5 MW Storage: 3,500 kW/1,750 kWh
Option 6	25.9 MW Wind, 12.6 MW Storage	Wind: 3 x 3.5 MW, 19 x 800 kW, 2 x 95 kW Storage: 12,600 kW/ 6,300 kWh
Option 7	25.8 MW Wind, 12.4 MW Storage	Wind: 6 x 3.5 MW, 3 x 800 kW Storage: 12,350 kW/ 6,175 kWh

1.2 Economic Assessment

The total estimated capital cost for each Option is presented in Figure 1-1. The capital costs range from $187 M to $2,037 M for the different Options.

As expected, the fully interconnected Options have considerably higher CAPEX costs than the microgrid Options. Option 2, which has high redundancy, has the highest CAPEX, followed by Option 1, which also has a loop configuration for the transmission line in the north. Option 4, which has a long radial line connecting all the communities, along with wind generation in the north near Voisey's Bay has the third highest CAPEX.

Option 6 has the lowest CAPEX, in spite of having one or more turbines and a battery serving each community, eliminating the long transmission lines leads to considerable cost savings.

Additionally, this option assumes L'Anse-au-Loop would continue to be served by Hydro Quebec, with a small portion of the energy requirements served by diesel gensets.

Option 7 also has a modest CAPEX. This Option connects communities, which can reduce the CAPEX for the wind and storage equipment; however, has the added CAPEX of transmission interconnections between the communities. Again L'Anse-au-Loop continues to be served primarily by hydropower from Hydro Quebec in this case.

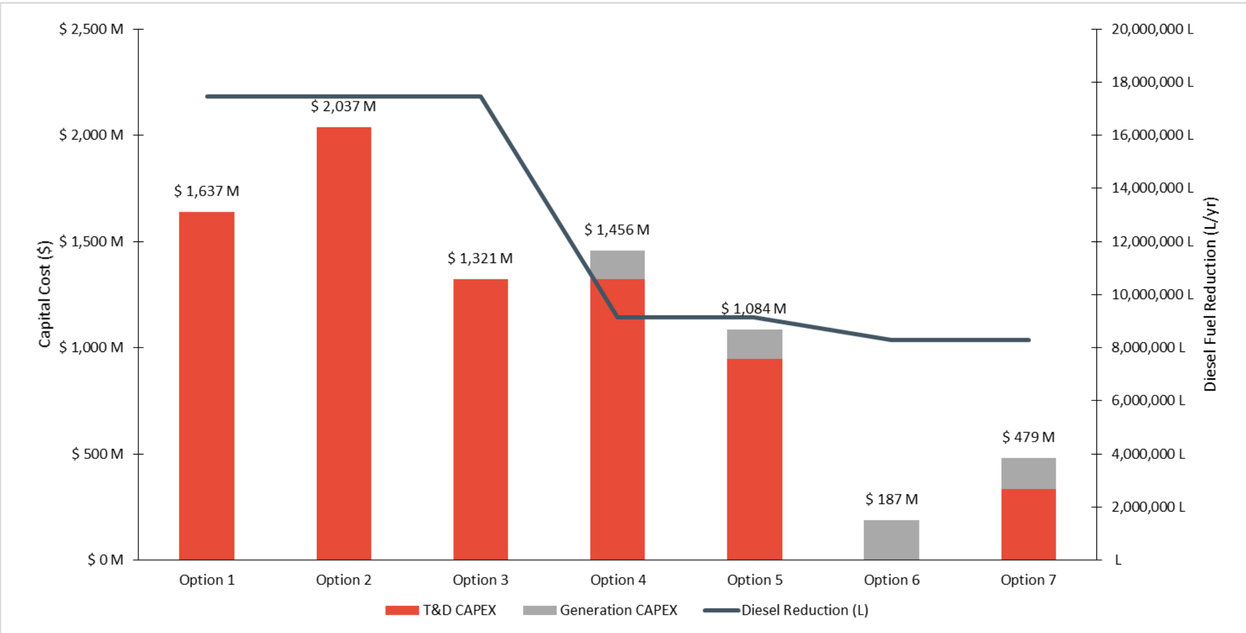

Figure 1-1: Capital Cost Comparison and Diesel Fuel Reduction Estimate for each Option.

The operating costs for the different Options are presented in Figure 1-2, broken down by component. For the Options with diesel gensets serving 50% of the community load, the fuel cost is the largest contributor to the annual spending. In Option 4 and Option 5, maintenance of the transmission lines is another key cost.

For the interconnected Options, the operating costs are driven by the cost to maintain the transmission lines and substations, and the cost associated with losses in the system (lost electricity). The losses have the potential to be optimized, based on the addition of reactive power support; however, the added capital cost of these reactive power support components needs to be weighed against the savings in annual losses.

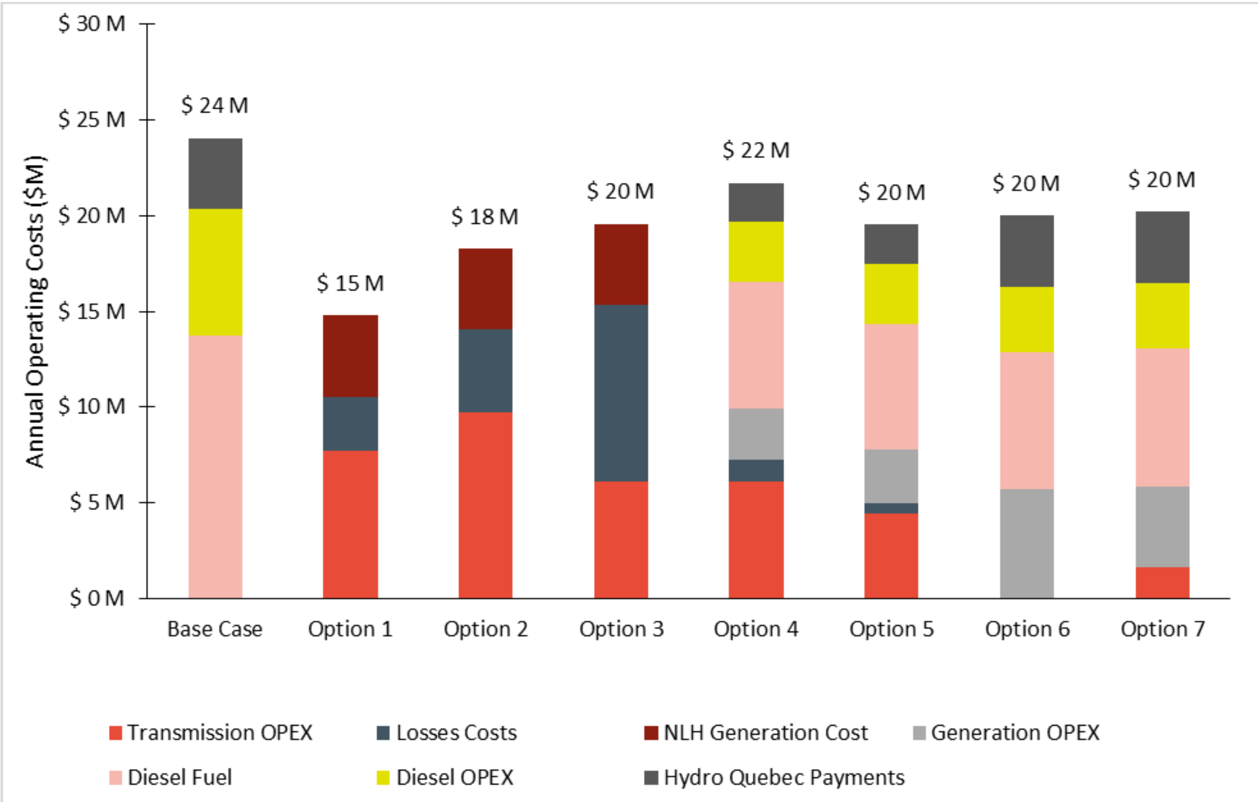

Figure 1-2: Total Operating Costs for Each Option, broken down by components

The total cost of ownership is presented in Figure 1-3 for each of the Options. The base case continues to have the lowest total cost of ownership over a 20-year period. However, this option also has the highest fuel consumption. Therefore, it is the most susceptible to volatile oil pricing and could increase if oil prices increase significantly in the future. Additionally, this Option does not necessarily align with policy and provincial and federal targets to reduce emissions.

Option 6 has the lowest total cost of ownership for the seven Options considered in this study. It also makes a significant reduction in diesel fuel consumption, reducing it by approximately 50%. This Option balances capital investment and annual costs.

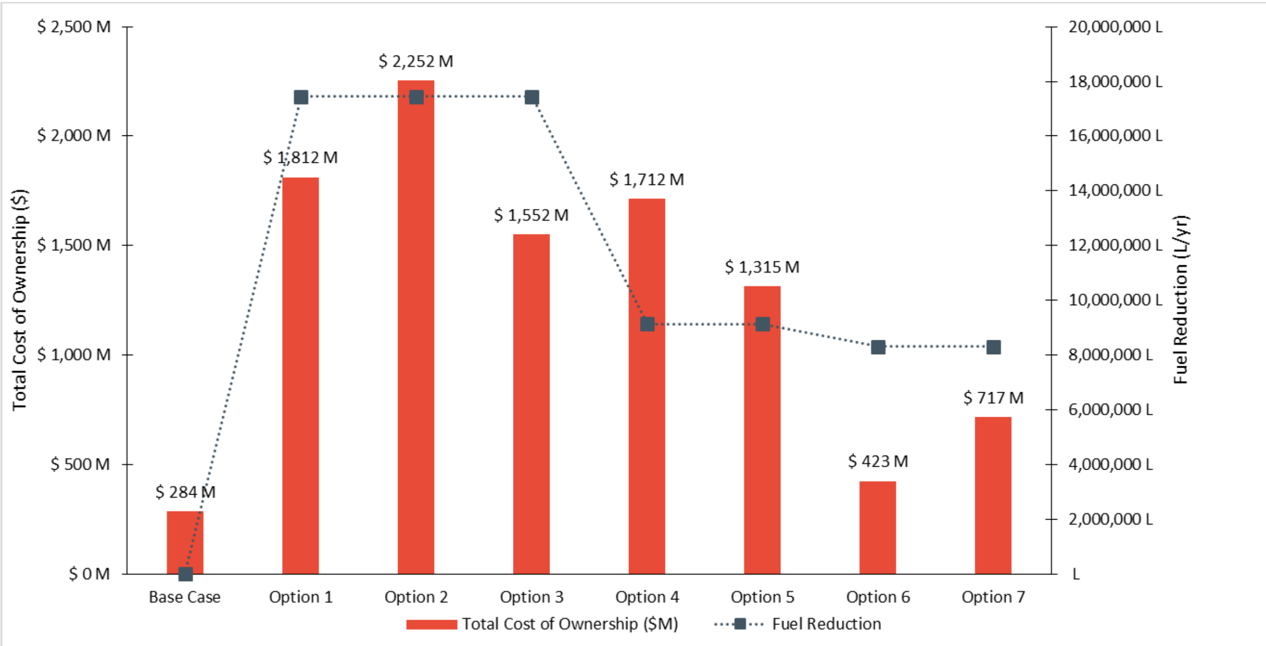

Figure 1-3: Comparison of Total Cost of Ownership to Annual Fuel Reduction

A high-level comparison of the different Options across a range of metrics is presented in Table 1-2. This table contrasts quantitative metrics (economics, fuel savings, generation requirements) with more qualitative considerations (operability and reliability) which may also influence the decision.

Table 1-2: Summary Comparison of the 7 Options across Various Metrics

Option	Generation Requirements	Diesel Fuel Reduction	Operability considerations	Reliability Considerations	Capital Cost	Annual Operating Cost	Total Cost of Ownership (20 year)
Base Case	0 MW	0 M L/yr	Continue to operate 3-4 engines in each community. Operability is the same as current.	Continued supply with only diesel in communities Reliability will be the same as current operations, with genset outages being the greatest source	$0 M	$24.1 M	$284 M
Option 1	0 MW	17.5 M L/yr	Maintenance would shift to substation inspections and preventative maintenance. Additionally, NL Hydro would need to maintain the transmission lines. In the north this would be icing management and the south a greater focus would need to be placed on vegetation management. These interconnected Options also experience considerable losses. In Option 3, some operating condition might result in stability issues under post contingency scenario	Redundant design in North South design is reasonable given accessibility Black Tickle & Norman Bay are likely the most vulnerable	$1,637 M	$14.8 M	$1,812 M
Option 2	0 MW	17.5 M L/yr		North is redundant, but using a parallel path leaves vulnerability in extreme weather South same as Option 1	$2,037 M	$18.3 M	$2,252 M
Option 3	0 MW	17.5 M L/yr		No redundancy in the North; however, reliability improved if VB can cover a portion of the load during outages South same as Option 1 May elect to keep the community gensets as backup	$1,321 M	$19.6 M	$1,552 M
Option 4	38.5 MW Wind	9.1 M L/yr	Substation and the transmission lines running from Voisey's Bay to the	System has little redundancy and centrally located renewable generation	$1,456 M	$21.7 M	$1,712 M

Option	Generation Requirements	Diesel Fuel Reduction	Operability considerations	Reliability Considerations	Capital Cost	Annual Operating Cost	Total Cost of Ownership (20 year)
			communities must be maintained. Additionally, generation at Voisey's Bay must be operated and maintained. When Voisey's Bay shuts down, a battery will be needed to manage wind variability. NL Hydro may elect to engage an IPP to own, operate and maintain the renewable generation.	Keeping diesel gensets as backup in the communities improves reliability System is vulnerable to outage with low windspeed, since renewables in single location			
Option 5	38.5 MW Wind, 3.5 MW Storage	9.1 M L/yr	North microgrid has the same considerations as Option 4. Operability of south microgrid requires maintenance of a centralized wind + storage hub and the transmission/distribution network. This Option eliminates the 300 km transmission connection or Muskrat Intersection switching station, which lowers transmission associated O&M requirements/costs. NL Hydro may elect to engage an IPP to own, operate and maintain the	North microgrid is the same as Option 4. The reliability of the south microgrid depends on the location of the wind generation. If located at Port Hope Simpson, reliability will be higher since the wind is centralized and there are several radial lines serving 1-3 communities. If wind generation is located in Cartwright, there would be 1 radial line serving all communities, lowering the reliability. Again, keeping diesel gensets in each community improves	$1,084 M	$19.6 M	$1,315M

Option	Generation Requirements	Diesel Fuel Reduction	Operability considerations	Reliability Considerations	Capital Cost	Annual Operating Cost	Total Cost of Ownership (20 year)
			renewable generation and storage for both the north and south.	reliability considerably.			
Option 6	25.9 MW Wind, 12.6 MW Storage	8.3 M L/yr	Many small microgrids which need O&M services, likely to have an IPP program to reduce burden on NL Hydro	Reliability is comparable to current design, with all generation within the community.	$187 M	$20.0 M	$423 M
Option 7	25.8 MW Wind, 12.4 MW Storage	8.3 M L/y	Fewer wind + battery installations lead to lower maintenance requirements; however, short run transmission lines must now be maintained. Again, may elect to engage an IPP to own and operate the wind + storage to reduce burden on NL Hydro.	Reliability improved slightly over base case, if gensets remain in each community. If there is a generation outage in one community, gensets can from other communities can be used as backup. If transmission connection is down, then gensets within each community can supply. In some cases, reliability may be unaffected by a regional power plant (or improved). This would need to be assessed on a case-by-case basis in a more detailed study.	$480 M	$20.2 M	$717 M

1.3 Conclusions and Next Steps

Reducing diesel dependence for the 15 isolated communities in Labrador is important to reduce energy associated emissions and reduce the high and variable costs associated with diesel fuel.

This report assesses 7 different Options to reduce diesel emissions in the communities, ranging from fully interconnected Options to microgrids with integrated wind + storage.

The lowest cost Option is the base case operation, keeping the diesel gensets within each community. This Option has a total lifecycle cost of approximately $120 M less than Option 6. However, continuing with the base case results in the highest GHG emissions, which does not support overall provincial and national initiatives to reduce emissions and fossil fuel dependence. Additionally, this Option has the highest risk to volatility in pricing, since the cost of generation is directly tied to the price of diesel fuel. Thus, when global oil prices are higher, the cost of generation will increase. Lastly, the cost of major overhauls and engine replacements have not been considered. Therefore, this will likely bring the base case closer in cost to Option 6 and 7.

Option 6 is the lowest cost Option studied in this analysis; with 1-3 wind turbines and a battery storage system located in every community. However, in this Option, 50% of the generation continues to be supplied by diesel fuel (except L'Anse-au-Loop). As well, there is high operating requirements, needing maintenance of 14 wind farms. If NL Hydro elects to go with this Option, it seems most probable that an independent power producer will be selected to own and operate each wind farm (and potentially the energy storage). This Option eliminates the need for costly transmission lines.

Option 7 is another viable option, blending the benefits of connecting the communities while reducing the high costs associated with long transmission lines. This Option improves reliability by connecting several communities in 4 microgrids. This reduces the number of wind farms from 14 to 6, which reduces the operating burden and the number of energy storage systems required. Additionally, the larger microgrids allow for larger turbines to be used, lowering the unit capital costs and the operating cost per kWh generated – which ultimately lowers the marginal energy costs. However, the main limitation of this Option is that it has lower diesel reduction and GHG reductions compared to the fully interconnected options. As well, 3 communities (Rigolet, Black Tickle, and L'Anse-au-Loop) remain isolated due to the high cost of the transmission lines to connect these communities.

For the interconnected Options, Option 3 has the lowest cost. This Option has the challenge of lower reliability, due to the single radial line. This long radial line also leads to higher losses. The reliability of Option 3 can be improved by keeping the diesel gensets in the community as backup. Additionally, if this Option is selected for further study, the location and number of reactive power support components could be optimized to minimized losses (or optimized to balance losses and CAPEX).

Option 1, 2, 4 and 5 also each have their own benefits and drawbacks. However, given the high capital cost of these Options and the high total cost of ownership, based on the current study, they are likely to be less desirable.

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1.3.1 Next Steps

As outlined above, there are several benefits and limitations to each of the Options which must be considered and weighed to determine the preferred path forward. Some of the next steps may include:

- Select preferred 2-3 Options for a more detailed prefeasibility study.
- Determine studies required to assess environmental impact of extended transmission lines for Options 1-5 & 7. Perform these environmental studies/assessments in needed.:
- Explore IPP programs/renewable integration opportunities to understand interest/costs.
- Explore opportunities to increase renewable energy penetration in Option 6 and/or Option 7, in order to further reduce diesel fuel consumption.
- Assess need to upgrade distribution voltage level within the communities.
- Community Consultations to understand desires of the community members.
- Assessment of soil contamination if planning to decommission diesel gensets.
- Wind monitoring campaign, particularly in the south, to select preferred sites.
- Discussions with Vale regarding future of Voisey's Bay and the potential connection Options.

2. Introduction

Newfoundland and Labrador Hydro (NL Hydro) is responsible for electricity supply to remote communities in the Labrador region. Currently NL Hydro owns and operates diesel gensets in each community along with a local distribution grid to supply electricity to the customers within each community.

NL Hydro is exploring its options to reduce diesel fuel consumption in these communities, ranging from installing local renewable generation at each community to constructing new transmission and distribution infrastructure to connect the communities to hydroelectric generating plants located at Churchill and Muskrat Falls.

Hatch was retained to complete an assessment of the various Options for supplying electricity to the communities in Labrador.

2.1 Background

There are fifteen (15) remote communities in Labrador that are currently served by NL Hydro, including six (6) along the northern coastal region of Labrador and nine (9) along the southern coast. The communities are shown in Figure 2-1.

Figure 2-1: Locations of the remote communities in Labrador in relation to Churchill Falls, Muskrat Falls and Voisey's Bay Mine.

The northern communities are not inaccessible by road, and only seasonally accessible by barge; however, can be reached throughout the year by air. The diesel fuel must be brought in and stored over the winter months, when cost-effective transportation is unavailable. Many of the southern communities have year-round road access, with the exception of Black Tickle and Norman Bay. The diesel fuel storage requirements are lower for these communities, since they can receive shipments all year.

As these communities are currently solely supplied by diesel fuel, the cost for NL Hydro to generate electricity is highly volatile, since it is subject to global oil pricing. As well, there is increasing pressure to reduce the amount of diesel fuel used, and emissions associated with the generation of electricity for these communities.

Therefore, NL Hydro is exploring different options to reduce fuel consumption through the integration of renewable generation.

2.2 Previous Analysis

In 2014, NL Hydro completed a preliminary study to assess the potential to fully interconnect all of the communities, along with the Voisey's Bay mine to hydroelectric generation stations at Churchill Falls and Muskrat Falls. The communities would be supplied by hydro power from these sites.

This study proposed connecting the northern communities to both Churchill and Muskrat Falls using a 138-kV transmission loop. The loop configuration was selected to provide an increased level of reliability due to the remote nature of the communities, harsh climate and inaccessibility during the winter. It was concluded that if there was only a single line, any outage would lead to extended periods of lost electricity. Additionally, redundancy was built into the substations for each community, with two fully redundant parallel transformers used to supply each community.

For the southern communities, a radial 138 kV line from Muskrat Falls supplied electricity to a switching station to reduce the voltage to 69 kV. The communities were then supplied with a 69-kV system configured as a set of radial transmission lines. In some cases, the voltage was further stepped down to 25 kV. Since the majority of these communities are accessible year-round, it was determined that a radial line was sufficient, since it could be repaired fairly quickly in the event of an outage. A single transformer was used for each community since they are more accessible. NL Hydro also proposed having a mobile transformer that could be brought to the communities in the event of an outage.

The layout of this Option is illustrated by the colored lines in Figure 2-1 above.

Based on NL Hydro's assessment in 2014, the estimated capital cost for the full system was $2.06 billion CAD[1]. This excluded the undersea cable required to supply Black Tickle. The Northern grid was estimated to cost $1.29 billion CAD while the Southern grid was estimated to cost $0.77 billion CAD[2].

This system will be referred to as Option 1 in the following study and used as the baseline to compare all other options.

2.3 Objectives

The objective for the study is to assess six (6) alternative Options (for a total of seven (7) Options) for electricity supply to the fifteen (15) remote communities. The Options will be assessed on the following metrics:

[1] $15 million has been removed from the cost since William's Harbour no longer requires interconnection.
[2] $15 million has been removed from the cost since William's Harbour no longer requires interconnection.

- Load flow considerations for highly interconnected Options;
- Option to upgrade distribution to 25 kV within the communities;
- Generation requirements;
- Diesel fuel offset;
- Operability considerations;
- Reliability considerations;
- Capital cost; and
- Operating cost;

For Options where the communities will be connected to Churchill and Muskrat Falls, it will be assumed that 100% of the electricity is supplied by these hydroelectric plants. Therefore, an estimated cost for the diesel plant decommissioning has been prepared and included in this report.

3. Interconnection Options Assessed

3.1 Configurations

Seven (7) interconnection Options were studied, as follows:

- **Option 1:** Fully interconnected system as outlined in original NL Hydro study. Northern Communities are connected on a 138-kV loop and Southern Communities are connected on a 69-kV radial line. 100% of the electricity needs will be served by Churchill Falls or Muskrat Falls.
- **Option 2:** Fully interconnected system. Northern Communities are connected on two parallel 138 kV radial lines running from Happy Valley Terminal Station, drawing electricity from Muskrat Falls and Churchill Falls, to Voisey's Bay and Southern Communities are connected on a 69-kV radial line. 100% of the electricity needs will be served by Churchill Falls or Muskrat Falls.
- **Option 3:** Fully interconnected system. Northern Communities are connected on a single 138 kV radial line running from Happy Valley Terminal Station, drawing electricity from Muskrat Falls and Churchill Falls, to Voisey's Bay and Southern Communities are connected on a 69-kV radial line. 100% of the electricity needs will be served by Churchill Falls or Muskrat Falls.
- **Option 4:** Large microgrid system. Renewable generation is located in the North at Voisey's Bay. A radial line supplies electricity to the communities from Voisey's Bay. Some communities may not be connected due to the cost associated with the long

transmission line. Voltage selection will be kept the same with 138 kV serving the north and 69 kV serving the south. It is assumed that 40-50% of the electricity generation (on a MWh basis) will be supplied by renewable sources.

- **Option 5:** Two microgrids. The Northern Communities will be served by a 138-kV radial transmission line connected to centralized renewable generation at Voisey's Bay. The Southern Communities will be served by a 69-kV radial system. The generation will be centralized, located at Port Hope Simpson or Cartwright. It is assumed that 40-50% of the electricity generation (on a MWh basis) will be supplied by renewable sources.
- **Option 6:** Isolated microgrids. Each community will be served by its own renewable generation and microgrid. It is assumed that 40-50% of the electricity generation (on a MWh basis) will be supplied by renewable sources.
- **Option 7:** Optimized isolated microgrids. Several communities will be connected together based on optimized designs with centralized generation centers. Design is optimized based on transmission line cost. It is assumed that 40-50% of the electricity generation (on a MWh basis) will be supplied by renewable sources.

When designing the configurations for the mid-size microgrids, two main factors were considered:

- Proximity of the communities (to minimize transmission costs); and
- Size of the communities (to reduce renewable curtailment). This consideration is important for small communities where it may not be economical to install a standalone wind + battery hybrid power system.

The proposed configurations are as follows:

- Nain – Natuashish – 69 kV x 145 km transmission line.
- Hopedale-Makkovik-Postville – 69 kV x 232 km transmission line.
- Rigolet to remain isolated due to long distance (>200 km from Makkovik) and reasonable size load that can sustain its own wind farm.
- Cartwright – Paradise River – 69 kV x 47 km.
- Black Tickle to remain isolated due to long transmission connection (> 210 km) and the need for a subsea cable.
- Port Hope Simpson – Charlottetown – Norman Bay – St. Lewis – Mary's Harbour – 25 kV x 220 km.

- L'Anse-au-Loop to remain isolated due to long transmission connection (>143 km) and low-cost hydro generation (13-15 cents/kWh) available from Hydro Quebec. It is also not recommended to install wind generation for L'Anse-au-Loop since this hydro connection has a lower cost.

3.2 Details on Each Community

A summary of the load and generation data for the 15 isolated communities is presented in Table 3-1 and Table 3-2, showing various generation and load metrics.

The 2024 forecast was used to estimate the generation needs for the communities in the future. The forecasted peak demand, total generation and peak load factor for each community are presented in Table 3-3.

Table 3-1: Summary of Details on 2019 generation for the Isolated Communities in Labrador

Community	Nain	Natuashish	Hopedale	Makkovik	Postville	Rigolet	Cartwright
Loop	Northern	Northern	Northern	Northern	Northern	Northern	Southern
Net Peak 2019 (kW)	2,247	1,685	1,158	9,42	413	786	1152
Net Generation 2019 (MWh)	9,554	8,895	5,410	4,316	1,847	2,980	4433
Fuel Consumption 2019 (L)	2,861,293	2,511,112	1,586,491	1,349,274	561,127	848,367	1,311,785
Annual Average Fuel Efficiency (kWh/L)	3.47	3.69	3.54	3.32	3.41	3.66	3.52
2018 Fuel Price ($/L)	$1.08		$1.16	$1.06	$1.01	$0.99	$1.13
Diesel Capacity (kW)	3,755	3,337	2,629	1,765	1,067	1,320	2,220
Distribution Voltage (kV)	4.16	25	4.16	4.16	4.16	4.16	4.16
Comments		*NL Hydro is responsible for Operation and Maintenance of the electricity grid; it does not own the diesel gensets or the electricity grid					

Table 3-2: Summary of Details on 2019 generation for the Isolated Communities in Labrador

Community	Paradise River	Black Tickle	Norman Bay	Charlotte-town	Port Hope Simpson	Mary's Harbour	Saint Lewis	L'Anse-au-Loop
Loop	Southern	Southern	Southern	Southern	Southern	Southern	Southern	Southern
Net Peak 2019 (kW)	63	285	52	1,503	755	1,071	376	6,878
Net Generation 2019 (MWh)	191	1,166	209	4,788	3,089	4,191	1,448	26,947 (1,505 from diesel)
Fuel Consumption 2019 (L)	91,885	337,270	72,389	1,484,621	1,309,722	867,581	429,572	611,757
Annual Average Fuel Efficiency (kWh/L)	2.49	3.62	2.88	3.39	3.70	3.31	3.52	3.28
2018 Fuel Price ($/L)	$1.13	$1.01	$1.19	$1.12	$1.14	$1.07	$1.12	$1.00
Diesel Capacity (kW)	148	1,005	160	1,635	1,725	2,615	1,020	8,050
Distribution Voltage (kV)	4.16	4.16	4.16	4.16	12.5	4.16	12.5	25
Comments						240 kW mini hydro, Solar PV and Battery are planned to be installed in 2021		buy up to 6.5 MW continuous from HQ at $150/MWh

Table 3-3: Community Load forecast for 2024

Community	Peak Demand (2024)	Generation Requirements (2024)	Peak Load Factor (2024) Ratio of Average demand to peak demand
Nain	2,346 kW	10.6 GWh	52%
Natuashish	2,152 kW	10.7 GWh	57%
Hopedale	1,307 kW	6.0 GWh	52%
Postville	945 kW	4.6 GWh	49%
Makkovik	445 kW	1.9 GWh	55%
Rigolet	720 kW	3.1 GWh	49%
Paradise River	75 kW	0.2 GWh	33%
Cartwright	1,014 kW	4.4 GWh	50%
Black Tickle	279 kW	1.1 GWh	46%
Port Hope Simpson	748 kW	3.2 GWh	47%
Charlottetown	1,565 kW	5.8 GWh	39%
Norman Bay	48 kW	0.2 GWh	49%
St. Lewis	383 kW	1.5 GWh	51%
Mary's Harbour	995 kW	4.4 GWh	45%
L'Anse-au-Loop	5,846 kW	27.5 GWh	54%

3.3 Load Flow Study Findings

This section discusses the results of the load flow studies for the Options as described in Section 2.1. The assessments are preliminary, and the objective was to conduct a load flow analysis in order to determine if the proposed system will perform within system limits and allowed impacts for possible pre-contingency and post-contingency (N-1) conditions. The impact of the studied interconnection Options on the rest of the grid is not assessed in this study. Further studies and design will be required, which is beyond the scope of work of this report, should NL Hydro decided to proceed with any of the studied Options.

For each of the interconnected Options, the load flow analysis was carried out for both (a) 2024 peak load forecast and (b) light load levels provided by NL Hydro. Power factors used for this study are based on previous NL Hydro analysis (Peak Load = 0.95; Light Load = 0.90). Table 3-4 provides load forecast for the communities used in this study.

Table 3-4: Load Forecast for the Labrador Communities

Communities	Peak Load Forecast (MW)	Light Loading (MW)
Voisey's Bay (VB)	43.00[3]	24.00
Nain (NAN)	2.35	0.29
Natuashish (NAT)	2.15	0.48
Hopedale (HPD)	1.31	0.15
Postville (POV)	0.45	0.06
Makkovik (MAK)	0.94	0.16
Rigolet (RIG)	0.72	0.09
Paradise River (PRV)	0.07	0.01
Cartwright (CWT)	1.01	0.19
Black Tickle (BKT)	0.28	0.05
Norman Bay (NOB)	0.05	0.01
Charlottetown (CWT)	1.57	0.18
Port Hope Simpson (PHS)	0.75	0.14
St. Lewis (STL)	0.38	0.06
Mary's Harbour (MHR)	1.00	0.16
L'Anse au Loup (LAL)	5.85	0.96
Total	**61.88 MW**	**26.99 MW**

3 Based on past project for VB

Select contingencies were identified and steady state contingency analysis was studied at both peak load and light load levels to understand the voltage response and thermal concerns. Each of the interconnected Options is individually discussed in subsequent sections of the report, along with load flow results and estimated costs. In addition, the following comments apply to the analysis in general:

- The loads were modelled as constant MVA for both pre- and post-contingency
- The PSSE system model provided by NL Hydro was used and updated based on any changes that each of the Options will represent. Studies are set up by first tuning the pre-contingency base case representation of the studied system.
- The power flow cases contain switched shunts at select buses, as proposed by NL Hydro, represented as synchronous condensers (with a very large impedance) with continuous control with the nominal bus voltage set to 1.0 pu. The amount of reactive power required to maintain the voltage to 1.0 pu was then determined. In addition, further consideration is required whether to install the reactors on the line or the bus.
- The placement of reactive power compensation devices at suitable locations within the system as well as determining the optimal Mvar ratings of shunt devices requires additional assessment that is beyond the present scope of work.
- Pre-contingency criteria entails that the power flow in all elements should be at or below normal rating and voltages shall be kept within the range of 0.95 – 1.05 pu. For contingency operation, steady state bus voltages must be kept in the range of 0.90 – 1.10 pu as per the NL Hydro steady state voltage criteria.
- Given that most of the transformers connected to the projects do not have the capability of automatic load tap changing, the tap changers are locked in power flow solution settings. Switchable shunts are allowed to operate when determining the voltages and branch flows during normal and emergency situations.

3.3.1 Option 1

This Option (as illustrated in Appendix B – Figure 1) connects communities in northern Labrador via a 138-kV loop, tied to both Churchill Falls (CHF) and Muskrat Falls. It is assumed that no generation is connected at Voisey's Bay's (VB). For southern communities to be connected to Muskrat Falls via a radial line from Muskrat Falls to L'Anse-au-Loop, radial transmission lines are tapped off the main transmission line at different points to serve the communities.

The load flow study is setup by first tuning the pre-contingency base-case representation of the studied system. The PSSE model provided by the client contains switched shunts at select buses, which were replaced by synchronous condensers having continuous control with the nominal bus voltage set to 1 pu. An additional shunt reactor modelled as a synchronous condenser (with bus voltage held at 1.0 pu) was inserted at Churchill Falls to compensate the line charging of the 361 km CHF-VB 138 kV transmission line.

The bus voltages and power flows were found to be within the acceptable limits during the normal condition. The pre-contingency steady state load flow results are provided in Appendix C.

Next, the following N-1 line contingencies, based on our experience and design of the studied Option, are established and simulated to assess the performance of the studied Option no. 1 under the single contingency outage. The following contingencies are studied at both peak load and light load levels to understand the voltage response and thermal concerns:

- Loss of a transmission line between Churchill Falls and Voisey's Bay (Length ~361 km).
- Loss of a transmission line between Happy Valley Terminal Station (HVTS) and Rigolet (Length ~188 km).

Under both contingencies, the power flow of the transmission line changes as the system becomes radial. It was assumed that each of the new 138 kV transmission lines have a continuous thermal rating of about 150 MVA (Darien, AAAC, 559.5 kcmil) based on the manufacturer's datasheet. The thermal loading of all the new lines was well under the maximum limit. Additionally, the bus voltage magnitudes changed but stayed within the ± 10% limits.

Table 3-5 below provides the required values for switched shunt elements at nominal bus voltage of 1 pu to provide reactive power compensation to keep the subsystem voltages at acceptable levels with and without contingencies. It is to be noted that the process of determining the optimal shunt element sizes and selection and placement of reactive power compensation devices is complex and involves detailed study and analysis, which is beyond the present scope of work.

Table 3-5: Mvar Ratings of Required Shunt Elements

Bus No.	Bus Name	Pre - Contingency	Post – Contingency
2	CHF 138 kV	-73 Mvar	-73 Mvar
123	MFA_INT 138 kV	-17 Mvar	-16 Mvar
3101	LAL 69 kV	-3/+2 Mvar	-3/+2 Mvar
3402	Makkovik 138 kV	-26 Mvar	-25/+20 Mvar
4001	Natuashish 138 kV	-15 Mvar	-15/+5 Mvar
4501	VB 138 kV	+31 Mvar	+36 Mvar

The project components required for the construction of Option1 and indicated CAPEX/OPEX are provided in Section 7.

3.3.2 Option 2

Option 2 (as illustrated in Appendix B – Figure 2) entails that Northern Labrador communities are supplied by two parallel lines running from Happy Valley Terminal Station. It is assumed that no generation is connected at VB. Whereas, southern communities connected to Muskrat Falls via 69 kV radial line from Muskrat Falls to L'Anse-au-Loop.

In the pre-contingency case, the sub-system steady state voltages and power flows are within the acceptable limits. Similar to Option 1, reactive power compensation is required to keep the voltages within acceptable limits.

The maximum and minimum pre-contingency voltages are provided in Table 2-6.

Table 3-6 Maximum and Minimum Pre-Contingency Voltages

Peak Load Levels:	Light Load Levels:
0.9900 – 1.0300 pu @138 kV buses 1.0000 – 1.0182 pu @ 69 kV buses	1.0000 – 1.0413 @ 138 kV buses 1.0000 – 1.0408 @ 69 kV buses

The pre-contingency steady-state load flow results are provided in Appendix C.

Next, N-1 contingency studies were carried out for the loss of following single element, including:

- Loss of one transmission line between Happy Valley TS and Rigolet (Length ~188 km).
- Loss of a shunt reactor at Makkovik 138 kV bus.

No post-contingency thermal violations were identified on circuits in Option 2. However, the loss of a shunt reactor at the Makkovik 138 kV bus resulted in voltage violations at several buses, specifically under light load operating conditions as presented in Table 3-7.

Table 3-7: Snapshot of over-voltage pockets due to loss of a reactor at Makkovik

Bus No.	Base kV	Voltage (pu)	Actual Voltage (kV)
317	138	1.1201	154.57
3402	138	1.1401	157.33
3601	138	1.1249	155.24
3301	4.16	1.1199	4.66

Bus No.	Base kV	Voltage (pu)	Actual Voltage (kV)
3501	4.16	1.1398	4.74
3701	4.16	1.1248	4.68

The over voltage problems due to the above-mentioned contingency could be corrected by re-examining the reactive power compensation strategy or performing some system adjustments. For instance, one of the system adjustment options considered was opening one of the parallel lines between Makkovik (3402) and Rigolet (317). After the system adjustment, the post-contingency bus voltages are within or close to the applicable emergency voltages limits as shown in Table 3-8.

Table 3-8: Post-contingency Voltages after the System Adjustment

Bus No.	Base kV	Voltage (pu)	Actual Voltage (kV)
317	138	1.0830	149.46
3402	138	1.1093	153.09
3601	138	1.1016	152.02
3301	4.16	1.0829	4.51
3501	4.16	1.0900	4.61
3701	4.16	1.1015	4.58

In Table 3-9 below, the values for required switched shunt elements at nominal bus voltage (1 pu) with and without contingency are provided. Further study is required for validation, which is beyond the present scope of work.

Table 3-9: Mvar ratings of Required Shunt Elements

Bus No.	Bus Name	Pre – Contingency	Post - Contingency
123	MFA_INT 138 kV	-18 Mvar	-19 Mvar
3101	LAL 69 kV	-3/+3 Mvar	-3/+3 Mvar
3402	Makkovik 138 kV	-50 Mvar	-46 Mvar
4001	Natuashish 138 kV	-27 Mvar	-53 Mvar
4501	VB 138 kV	+31 Mvar	+30 Mvar

The project components required for the construction of Option 2 and indicated CAPEX/OPEX are provided in Section 7.

3.3.3 *Option 3*

Option 3 (as illustrated in Appendix B – Figure 3) has the Northern Labrador communities connected from Happy Valley Terminal Muskrat Falls. The loads in the Northern Labrador area to be supplied from CHF through 138 kV circuits. It is assumed that no generation is connected at VB. Whereas, southern communities connected to Muskrat Falls via 69 kV radial line from Muskrat Falls to L'Anse-au-Loop.

Under pre-contingency condition, the steady state voltages and power flows of the sub-system are within the acceptable limits. Similar to Option 1 and 2, it was observed that reactive power compensation is required to keep the voltages of the sub-system within acceptable limits. In Table 3-10 below, the shunt element sizes required at nominal bus voltage (1 pu) without contingency are provided.

Table 3-10: Mvar ratings of Required Shunt Elements

Bus No.	Bus Name	Pre – Contingency
123	MFA_INT138 kV	-16 Mvar
3101	LAL 69 kV	-3/+3 Mvar
3402	Makkovik 138 kV	-18/+21 Mvar
4001	Natuashish 138 kV	-11/+5 Mvar
4501	VB 138 kV	+35 Mvar

During light loading condition, a switched shunt reactor of approximately 18 Mvar is required at the Makkovik bus to absorb the surplus reactive power produced by the 206 km line from Rigolet to Makkovik. Additionally, 21 Mvar switched shunt capacitor at Makkovik is required during peak loading condition.

N-1 contingency was carried out for loss of shunt reactor at Makkovik. Under peak loading scenario, the loss of the shunt element resulted in non-convergence of the power flow solutions. As such, the system did not satisfy the contingency criterion. To mitigate the concern, the current reactive power compensation strategy needs to be examined. Further studies including voltage stability analysis needs to be performed before pursuing this Option. These studies are not part of this report.

The project components required for the construction of Option 3 and indicated CAPEX/OPEX are provided in Section 7.

3.3.4 *Option 4*

Option 4 (as illustrated in Appendix B – Figure 4) has Northern Labrador communities connected by a 138-kV radial line from Voisey's Bay with generation at Voisey's Bay and that the communities in the South are connected to the North via a long radial transmission line (this was estimated as approximately 488 km based on NL Hydro's indication that the transmission lines follow the road) emanating from Rigolet.

Under the pre-contingency scenario, over voltages were identified at the Rigolet bus. The highest voltage value of 150.5 kV (i.e. 1.0910 pu) was observed during light loading condition. As a mitigation method for the over-voltage occurrence, a shunt reactor (modelled as a synchronous condenser) was inserted to absorb the surplus reactive power under different loading conditions while keeping the bus voltage at 1.0 pu. It is worth noting that optimization could be made as it relates to placement and operation of reactive compensation devices, however, that requires deeper analysis, which is beyond the scope of work. The placement of the shunt reactor at Rigolet brings the voltage within permissible limits. The pre-contingency steady state load flow results are provided in Appendix C.

For N-1 contingency analysis, the impact of loss of a shunt reactor at Makkovik and Natuashish (one at a time) was studied. The voltages stayed within the emergency limits. In Table 3-11 below, the values for the required switched shunt elements at nominal bus voltage (1 pu) corresponding to pre- and post-contingency states are provided. Under N-1 contingency scenario for a loss of the shunt reactor, there were moderate increases in the reactor sizes at the neighboring buses compared to the pre-contingency scenario.

Table 3-11: Mvar Ratings of Required Shunt Elements

Bus No.	Bus Name	Pre – Contingency	Post – Contingency
123	MFA_INT138 kV	- 21 Mvar	- 21 Mvar
317	Rigolet 138 kV	-23 Mvar	-35 Mvar
3101	LAL 69 kV	- 3/+2 Mvar	- 3/+2 Mvar
3402	Makkovik 138 kV	-18 Mvar	-20 Mvar
4001	Natuashish 138 kV	- 6 Mvar	- 13 Mvar

In addition, the impact of loss of shunt reactor at Muskrat 138 kV bus (no. 123) was analyzed during light loading condition. The load flow results showed a large number of over-voltages above 1.1 p.u. The minimum and maximum pre- and post-contingency voltages are provided in Table 3-12 below.

Table 3-12: Maximum and Minimum Pre- and Post-Contingency Voltages

Pre-Contingency:	Post-Contingency:
0.9802 – 1.0230 pu @ 138 kV buses 1.0000 – 1.0408 pu @ 69 kV buses	0.9804 – 1.2303 pu@ 138 kV buses 1.0000 – 1.239 pu @ 69 kV buses

The changes in voltages from pre-contingency to post-contingency range between ~ 1% to ~20%. For the above contingency, the post contingency voltages are beyond the emergency limits. Some system adjustments as well as reactive power planning is required to bring the system to a secure state.

In addition, there is the question of increased O&M and reliability challenges associated with Option 4 as it contains long radial lines serving remote communities. Unlike Option 1, where a downed line conductor or structure can be sectionalized for load to be served before repairs are completed, load served in Option 4 is sourced from Voisey's Bay via radial transmission line and cannot be re-energized until the repairs are completed.

The project components required for the construction of Option 4 and indicated CAPEX/OPEX are provided in Section 7.

3.3.5 Option 5

Option 5 (as illustrated in Appendix B – Figure 5) entails Northern Labrador communities connected by a 138-kV radial line with generation at Voisey's Bay. Additionally, the Southern communities are connected in a radial microgrid, with generation at Port Hope Simpson.

Under pre-contingency scenario, the bus voltages and line flows are within acceptable limits at peak load levels. However, under voltages were identified on some buses during peak loading as shown in Table 3-13.

Table 3-13: Buses with Pre-contingency Voltages under 0.95 pu

Bus name and (Bus number)	Base kV	Pre-contingency Voltage (pu)
CWT (1701)	25 kV	0.9468
Norman Bay (1901)	25 kV	0.9483
Norman Bay (2001)	4.16 kV	0.9475

As a mitigation method for the under-voltage problems, a shunt capacitor was attached at Norman Bay (modelled as a synchronous condenser with nominal bus voltage held at 1 pu) to inject reactive power, as required. The placement of the shunt capacitor at Norman Bay brought the voltages within permissible limits. The pre-contingency steady state load flow results are provided in Appendix C.

Similar to the other Options, it was identified that reactive power compensation is required to keep the voltages of the sub-system within acceptable limits.

Next, the N-1 contingency studies were carried out for the loss of following single element, including:

- Loss of a shunt reactor at Makkovik 138 kV bus.

In practice, the shunt reactor at Makkovik will be a line reactor installed on the 206 km transmission line between Makkovik and Rigolet. Therefore, tripping of a line reactor will also result in cross-tripping of the 138-kV line. In the event of a loss of a shunt reactor, no post-contingency thermal issues were identified. However, the loss of a shunt reactor resulted in voltage violations. The post contingency voltages at some buses were slightly higher than the acceptable emergency limits. Table 3-14 provides the pre- and post-contingency steady-state voltages of those buses for the light loading condition.

Table 3-14: Pre- and Post-contingency Voltages for Light Loading Condition

Bus name and (Bus number)	Base kV	Pre-contingency Voltage (pu)	Post- contingency Voltage (pu)
Makkovik (3402)	138 kV	1.0000	1.1098
Postville (3601)	138 kV	1.0197	1.1026
Makkovik (3501)	4.16 kV	0.9997	1.1095
Postville (3701)	4.16 kV	1.0196	1.1024

To overcome the over-voltage occurrence, one of the system adjustment options considered was connecting a line reactor between Makkovik and Postville. After the system adjustment, the post-contingency bus voltages are within the applicable emergency voltage limits as shown in Table 3-15.

Table 3-15: Comparison of Post-contingency Voltages for Light Loading Condition

Bus name and (Bus number)	Base kV	Post- contingency voltages before connecting the line reactor (pu)	Post- contingency voltages after connecting the line reactor (pu)
Makkovik (3402)	138 kV	1.1098	1.0871
Postville (3601)	138 kV	1.1026	1.0907
Makkovik (3501)	4.16 kV	1.1095	1.0868
Postville (3701)	4.16 kV	1.1024	1.0905

In Table 3-16 below, the shunt elements required at the appropriate buses to hold the voltage at 1 pu are provided. In addition, a line reactor with a 5 Mvar rating is required, to be connected on the transmission line from Makkovik to Postville.

Table 3-16: Mvar Ratings of Required Shunt Elements

Bus No.	Bus Name	Pre – Contingency	Post – Contingency
1512	PHS 69 kV	- 7 Mvar	- 7 Mvar
1901	Norman Bay 25 kV	+1 Mvar	+1 Mvar
3101	LAL 69 kV	-1/+3 Mvar	-1/+3 Mvar
3402	Makkovik 138 kV	-20 Mvar	N/A
4001	Natuashish 138 kV	-8 Mvar	- 8 Mvar

3.3.6 Option 6 and 7

As these Options are based on an isolated microgrid in each community, load flow studies were not required.

Since the communities remain relatively isolated, there is no major transmission network to study.

3.4 Generation Requirements

For Options 4-7, new renewable generation will be installed in order to offset diesel generation. The target installation will be approximately 50% penetration in terms of energy with renewables + storage.

3.4.1 Assessment of Renewable Penetration vs. Installed Generation - Nain

A simulation has been completed investigating wind generation for Nain, in Northern Labrador. This analysis has been completed for the forecasted peak demand in 2024 for Nain (2.4 MW).

This simulation investigated the installation of 95 kW wind turbines, 800 kW turbines, and 3,500 kW turbines. Additionally, adding in a 30 min battery to cover the loss of a single turbine. Therefore, for each case, wind only and an operating reserve battery of 100 kW, 800 kW, and 2,500 kW for each turbine size, respectively. For the 3,500-kW turbine case, a 2,500-kW battery was selected since this is sufficient to cover the peak load in the event of the turbine loss. A 3,500 kW BESS would be unnecessary under the current assumptions.

Figure 3-1 shows the relationship between the number of installed turbines (and wind capacity), the levelized cost of energy (LCOE) and the renewable penetration level for the 800 kW and 3,500 kW turbines. The LCOE was calculated for a 20-year period. For the 800-kW turbine option, the LCOE for the wind + storage case is comparable to the forecasted diesel fuel price in 2024 for up to 1.6 MW of wind (or 2 turbines). A 50% renewable penetration is achieved with 5 turbines (4 MW of installed capacity).

For the 3,500-kW turbine option, only the single turbine option has an LCOE comparable to that of diesel fuel. However, with the 2,500 kW BESS this results in a renewable penetration of approximately 50% as well.

The LCOE of the 3,500-kW turbine option is always less than that of the 800-kW turbine option to achieve comparable renewable penetration. For medium to high penetration options, the 3,500-kW turbine configuration will have a lower overall levelized cost of energy.

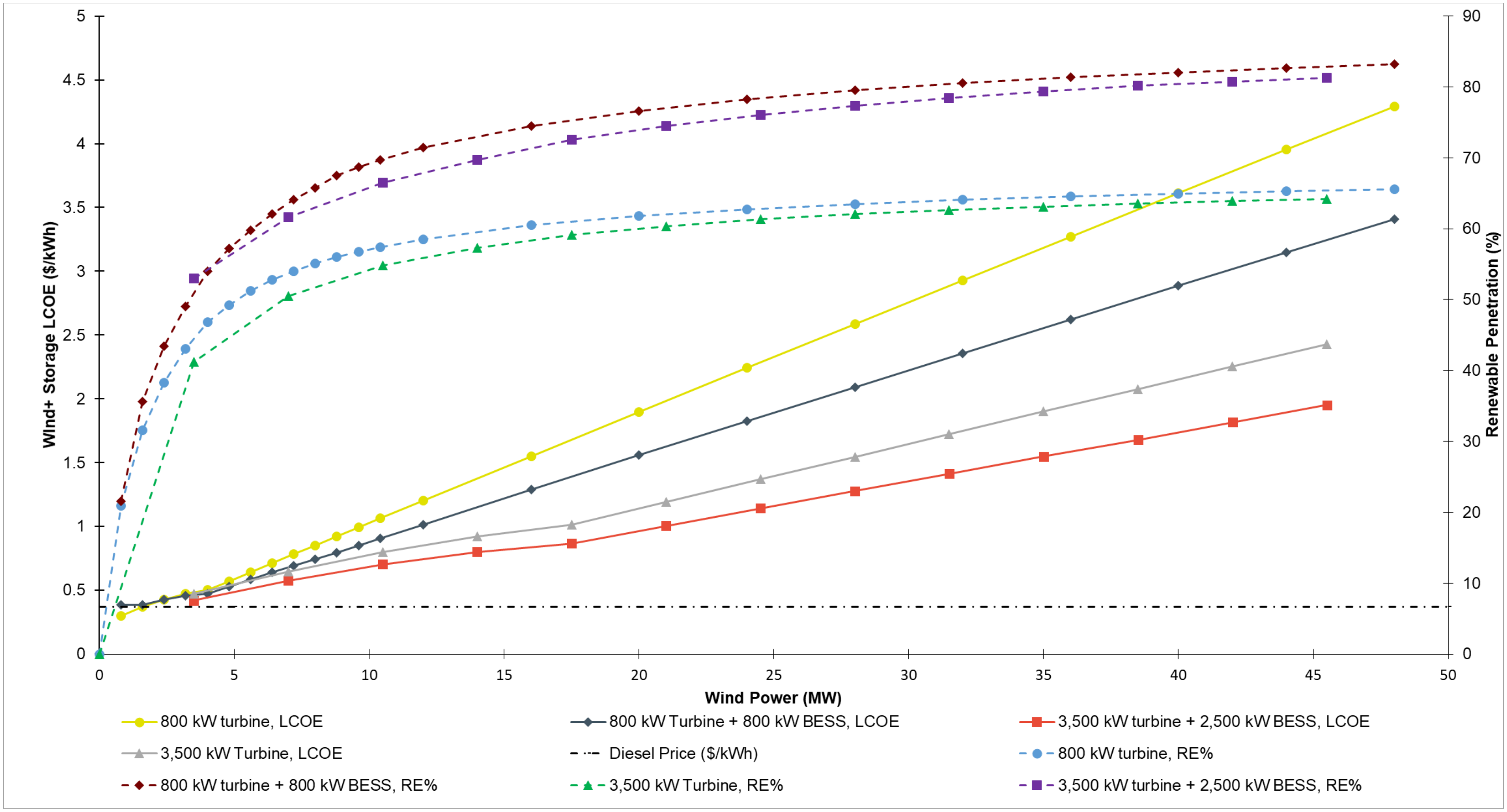


Figure 3-1: Relationship between installed wind capacity and Wind + Storage LCOE (for 20 years) and Renewable penetration, for 800 kW turbines and 3,500 kW turbines with and without an operating reserve battery.

Figure 3-2 illustrates the impact of turbine size on LCOE and capital expenditure for a 50% renewable penetration scenario. The most economical option for Nain is the 3,500-kW turbine with a 2,500-kW spinning reserve battery. This option has a wind + storage LCOE of $0.42/kWh which is slightly higher than the estimated $0.34/kWh for diesel generation (based on 2020 diesel pricing of $0.81/L and an operating cost of $0.11/kWh). The 800-kW turbine option is also viable, with an LCOE at $0.47/kWh. This option is beneficial if the project will be developed in phases. The 800-kW option also offers greater benefits for lower renewable penetration targets, with LCOE values for 1 or 2 turbines comparable to the estimated price of diesel. As seen, to generate sufficient capacity and energy for 50% renewable penetration, 35 x 95 kW turbines are required, which is costly and requires a large land area.

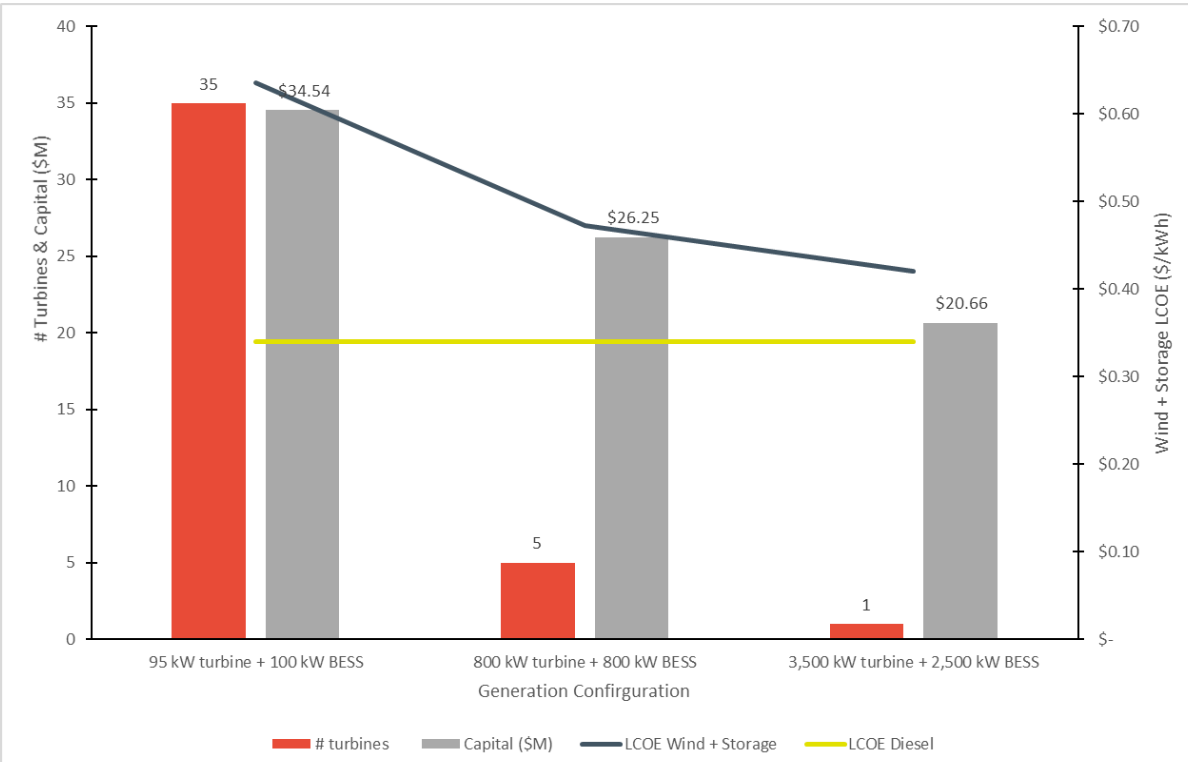


Figure 3-2: Relationship between wind turbine size and Wind + Storage LCOE (for 20 years) and CAPEX for approximately 50% renewable penetration. The scenario includes an operating reserve battery with a discharge duration of 30 min.

As shown in Figure 3-2, in order to achieve 50% renewable penetration, between 3.5-4 MW of generation is required. This is approximately 3 to 4 times the average load for Nain. This is a typical rule of thumb to achieve 50% renewable penetration and will be used to estimate the generation requirements for the other scenarios.

Note: A 3.5 MW turbine was used as a template turbine for this study. Currently, 3.5 MW to 4.2 MW turbines are the largest available options; however, turbine sizes are continually increasing, with new turbine models released every 2-3 years. If one of these options move forward, the assessment should be completed in greater detail using the wind turbine technology that is the state-of-the-art at the time of the assessment.

3.4.2 Option 1-3

For Options 1-3, the fully interconnected systems, all generation will be supplied by hydroelectric generating plants at Muskrat Falls and Churchill Falls. Therefore, no additional renewable generation is required.

3.4.3 Option 4

In Option 4, there is a centrally located generation hub at Voisey's Bay, which feeds the communities through a radial connection. A key advantage of locating wind generation near Voisey's Bay is that there are ongoing studies in the region. It may be possible to leverage the findings of these studies and select wind sites that have already been assessed. It may be possible to sell excess power generated by the wind farm powering the communities to Voisey's Bay, reducing the need for curtailment. Integrating with Voisey's Bay may also enable optimizing the wind farm size to supply both the communities and the mine. This may reduce the total capacity and number of turbines needed to achieve 50% renewable penetration, compared to supplying the mine and the communities separately.

Since the generation is connected at Voisey's Bay, the benefits of the existing diesel generation, with fast ramping capabilities, can be used to support grid stability. The capability of these diesel gensets allows for a high penetration of wind power to be integrated into the communities without a battery energy storage system.

The peak load for the communities was determined based on the summation of the peak load forecast for all communities, except for Mary's Harbour, Charlottetown, and Cartwright, which have summer peaks. For these three communities, the winter peak from 2018 was scaled based on the load forecast, to estimate the winter peak for 2024. The demand for Voisey's Bay Mine has been excluded, as it is assumed under this scenario it will continue to be supplied by on-site generation (either thermal generation or Vale-owned renewable generation).

A peak load factor of 52% was used (ratio between the peak demand and average demand) to estimate the average load across the communities for the entire year. The average load was calculated for each community based on its peak load factor. The generation requirements are based on a summation of the average load for all communities. Losses associated with the transmission lines have not been included.

Table 3-17: Community Demand and Generation Requirements for Option 4

Microgrid Loop	Peak Demand (2024)	Average Demand (2024)	Generation Requirements (2024)
North and South Combined	17.8 MW	9.6 MW	84.7 GWh

Typically, in order to achieve a 50% renewable penetration with wind generation, a wind farm with a capacity of 3 - 4 times the average load is required.

The wind speeds in the Voisey's Bay and Nain regions are high, resulting in good potential to achieve high penetration with for these communities.

Wind Generation with a capacity of 35 – 40 MW is required for a centralized generation hub. For this size of project, large wind turbines (between 3-4.2 MW) would be used. As outlined above, for this study, a 3.5 MW turbine has been used as the typical large turbine size for the preliminary calculations. However, the turbine model and sizing should be confirmed with the state-of-the-art at the time of development.

Table 3-18: Proposed Generation Mix for Option 4

Microgrid Loop	Generation Requirements	Configuration
North and South Combined	38.5 MW Wind Generation	11 x 3.5 MW turbines

As outlined above, due to the ramping capabilities of the Voisey's Bay Mine, and the fact that the community demand is relatively small compared to the mine's demand, a battery is not required in this case.

If a battery is required because the generation at Voisey's Bay is insufficient to maintain grid stability (or cannot be used for reasons unknown at this time), the recommended size would be 3.5 MW with a 30 min duration to cover the loss of a single turbine.

As this configuration will achieve approximately 50% renewable penetration, the remainder of the generation requirements are assumed to be covered by existing diesel generation within the communities.

It is not recommended to have a centralized diesel plant for this configuration given the long radial connection, which would lead to significant losses, as well as power quality and reliability issues, particularly for the communities in the south.

As the existing gensets reach end of life, they can either be replaced within the communities. Alternatively, it may be possible to create a generation hub for the region (e.g. separate hubs in the south and north, or a few hubs throughout the region). This would need to be studied in order to understand the impacts of the long radial lines, reliability of the system, and the savings in cost and O&M of a centralized hub.

3.4.4 Option 5

Option 5 proposes two large microgrid connections. In this configuration there would be a centralized generation hub at Voisey's Bay Mine to supply Nain, Natuashish, Hopedale, Postville, Makkovik, and Rigolet and a centralized generation hub supplying the Southern communities of Paradise River, Black Tickle, Cartwright, Charlottetown, Norman Bay, Port Hope Simpson, Mary's Harbour, St. Lewis, and L'Anse-au-Loop.

As with Option 4, a key advantage of locating some of the wind generation near Voisey's Bay is that there are ongoing studies in the region. It may be possible to leverage the findings of these studies and select wind sites that have already been assessed. It may be possible to sell excess wind generated by the wind farm powering the communities to Voisey's Bay, reducing the curtailment. Integrating with Voisey's Bay may also be possible to optimize the wind farm size to supply both the communities and the mine. This may reduce the total capacity and number of turbines needed to achieve 50% renewable penetration, compared to if the mine and the communities were supplied separately.

The peak load for the communities was determined based on the summation of the peak load forecast for all communities, except for Mary's Harbour, Charlottetown, and Cartwright, which have summer peaks. For these three communities, the winter peak from 2018 was scaled based on the load forecast, to estimate the winter peak for 2024. The demand for Voisey's Bay Mine has been excluded, as it is assumed under this scenario it will continue to be supplied by on site generation (either thermal generation or Vale-owned renewable generation).

A peak load factor of 53% was used to estimate the average load for the Northern communities, based on the weighted average peak load factor for these communities. For the southern communities, the weighted average peak load factor is 50%. The average load was calculated for each community based on its peak load factor. The generation requirements are based on a summation of the average load for all communities. Losses associated with the transmission lines have not been included.

Table 3-19: Community Demand and Generation Requirements for Option 5

Microgrid	Peak Demand (2024)	Average Demand (2024)	Generation Requirements (2024)
North	7.9 MW	4.2 MW	36.9 GWh
South	9.9 MW	5.4 MW	47.8 GWh

The same principles were applied as in the above cases, with a proposed wind generation capacity of 3 – 4 times the average load for each microgrid.

For the Northern microgrid, again it is likely that the generation will be located at or near Voisey's Bay. There is an excellent wind resource in the region and connection with the mine takes advantage of the backup generation on site that can be used for grid stability and to manage wind variability. This allows for the wind to be integrated at approximately 50% renewable penetration without the need for a battery to manage the variability. The remaining generation would be supplied by existing diesel gensets within each community.

For the Southern microgrid, it is estimated that six (6) turbines will be required. In the southern microgrid there are only small gensets within each community, therefore, the wind farm should be complemented by a 3.5 MW battery to smooth wind generation and cover the loss of a single turbine until diesel gensets can be brought online.

Table 3-20: Proposed Generation Mix for Option 5

Microgrid	Generation Requirements	Configuration	Batteries
North	17.5 MW Wind Generation	5 x 3.5 MW turbines	N/A
South	21 MW Wind Generation	6 x 3.5 MW turbines	3.5 MW/1.75 MWh Battery

There are two potential locations for the wind farm in the south microgrid: Connection at Port Hope Simpson or connection at Cartwright. The Port Hope Simpson connection point would be the preferred connection from an operational and power flow perspective. This connection is centrally located within the southern communities, reducing the losses to transmit electricity to each community. However, the wind resource at Port Hope Simpson is unknown; generally, in this southern region the wind speeds are lower than along the coastal region. If this Option is selected, a wind speed monitoring campaign would be required to confirm if Port Hope Simpson is a viable option for the wind farm.

By contrast, locating the wind farm at Cartwright allows for higher wind speeds and a better wind resource. However, this location is at the end of the radial line, which would lead to higher losses and lower reliability (which will be discussed further in Section 6). As well, given the coastal region, an appropriate site with enough space for six (6) turbines that can be installed economically must be identified.

It is assumed in these cases that the existing gensets within each community will continue to operate to support the remaining ~50% of the energy demand. As these gensets reach end-of-life, as discussed above, the tradeoff between co-location with the wind generation at a centralized hub, or replacement within each community should be considered when planning for replacement.

3.4.5 Option 6

Option 6 assesses the installation of renewables + storage as an isolated microgrid within each community. This Option eliminates the need to have long-distance transmission lines to connect the communities.

The forecasted peak and average demand for each community in 2024, as well as the peak load factor and generation requirements are presented in Table 3-21.

Table 3-21: Community Demand and Generation Requirements for Option 6

Community	Peak Demand (2024)	Average Demand (2024)	Peak Load Factor (2024)	Generation Requirements (2024)
Nain	2,346 kW	1,209 kW	52%	10.6 GWh
Natuashish	2,152 kW	1,226 kW	57%	10.7 GWh
Hopedale	1,307 kW	682 kW	52%	6.0 GWh
Makkovik	945 kW	464 kW	49%	4.6 GWh
Postville	445 kW	246 kW	55%	1.9 GWh
Rigolet	720 kW	349 kW	49%	3.1 GWh
Paradise River	75 kW	25 kW	33%	0.2 GWh
Cartwright	1,014 kW	504 kW	50%	4.4 GWh
Black Tickle	279 kW	130 kW	46%	1.1 GWh
Port Hope Simpson	748 kW	355 kW	47%	3.2 GWh
Charlottetown	1,565 kW	603 kW	39%	5.8 GWh
Norman Bay	48 kW	23 kW	49%	0.2 GWh
St. Lewis	383 kW	194 kW	51%	1.5 GWh
Mary's Harbour	995 kW	445 kW	45%	4.4 GWh
L'Anse-au-Loop	5,846 kW	3,134 kW	54%	27.5 GWh
Total	17,800 kW*	9,589 kW	N/A	85.2 GWh

*adjusted for summer peaking communities

In this Option, each community will have its own generation and energy storage, coupled with the existing diesel gensets serving the community. As above, a wind generation capacity of 3 - 4 times the average load was used to estimate the necessary capacity to achieve 50% penetration. The energy storage system was either sized to cover the communities' peak loads, or the loss of a single turbine, whichever was smaller.

The proposed generation configuration for each community is presented in Table 3-22. Comparing this to Option 4 and 5, less wind generation is required in this case, at nearly 26 MW of capacity since L'Anse-au-Loop is not served.

The key difference with this scenario is the amount of energy storage required. Since each community needs its own storage technology, over 16 MW of storage is required at a minimum to manage variability. This is significantly higher than Options 4 and 5, as these Options take advantage of the generation at Voisey's Bay to support power quality.

Table 3-22: Generation Requirements for Each Community

Community	Peak Demand (2024)	Wind Generation	Configuration	Energy Storage
Nain	2,346 kW	3,500 kW	1 x 3,500 kW	2,500 kW/1,250 kWh
Natuashish	2,152 kW	3,500 kW	1 x 3,500 kW	2,500 kW/1,250 kWh
Hopedale	1,307 kW	3,500 kW	1 x 3,500 kW	1,500 kW/750kWh
Postville	945 kW	2,400 kW	3 x 800 kW	800 kW/400 kWh
Makkovik	445 kW	800 kW	800 kW	500 kW/250 kWh
Rigolet	720 kW	1,600 kW	2 x 800 kW	750 kW/375 kWh
Paradise River	75 kW	95 kW	1 x 95 kW	100 kW/50 kWh
Cartwright	1,014 kW	2,400 kW	3 x 800 kW	800kW/400 kWh
Black Tickle	279 kW	800 kW	1 x 800 kW	300 kW/150 kWh
Port Hope Simpson	748 kW	1,600 kW	2 x 800 kW	800kW/400 kWh
Charlottetown	1,565 kW	2,400 kW	3 x 800 kW	800kW/400 kWh
Norman Bay	48 kW	95 kW	1 x 95 kW	50 kW/25 kWh
St. Lewis	383 kW	800 kW	1 x 800 kW	400 kW/200 kWh
Mary's Harbour	995 kW	2,400 kW	3 x 800 kW	800kW/400 kWh
L'Anse-au-Loop	5,846 kW	0 kW	0 kW	0 kW/0 kWh
Total North	**7,915 kW**	**15,300 kW**	**3 x 3.5 MW, 6 x 800 kW**	**8,550 kW/ 4,275 kWh**
Total South	**9,885 kW***	**10,590 kW**	**13 x 800 kW, 2 x 95 kW**	**4.050 kW/ 2,025 kWh**
Total	**17,800 kW***	**25,890 kW**	**3 x 3.5 MW, 19 x 800 kW, 2 x 95 kW**	**12,600 kW/ 6,300 kWh**

*adjusted for summer peaking communities

Generation for L'Anse-au-Loop has not been included since the levelized cost of energy of a wind + battery system is greater than that of the hydro power supplied by Hydro Quebec. However, if NL Hydro elects to build wind + solar generation at L'Anse-au-Loop, approximately 14 MW of generation (4 x 3.5 MW turbines) is required and a 3.5 MW/1.75 MWh BESS to manage wind variability.

Again, in this scenario, the existing diesel generation would remain to provide the remaining 50% of the demand. Since there is no interconnection, as the gensets reach their end of life, they would be replaced with a comparable engine (or a slightly larger engine to accommodate load growth).

3.4.6 Option 7

As outlined above, when designing the configurations for the mid-size microgrids, two main factors were considered:

- Proximity of the communities (to minimize transmission costs); and
- Size of the communities (to reduce curtailment). This consideration is important for small communities where it may not be economical to install a standalone wind + battery hybrid power system.

The proposed configurations are:

- Nain – Natuashish – 69 kV system, 145 km of transmission lines.
  - Nain and Natuashish are the northern most communities along the Labrador Coast. Connecting the communities can reduce the need for a second battery. However, based on their loads, the communities are large enough to support their own renewable generation installations of either several 800 kW turbines or 1-2 3.5 -4 MW turbines.
- Hopedale -Postville-Makkovik – 69 kV system, 232 km of transmission lines.
  - Due to Postville's comparatively small load (~450 kW peak) it is recommended to connect this community to achieve savings by co-locating several wind turbines. Additionally, these communities are reasonably close together and thus can be connected to take advantage of the excellent wind resource at either Makkovik or Hopedale.
- Rigolet to remain isolated.
  - It is recommended to keep Rigolet isolated due to the long transmission connection of ~ 206 km. This transmission connection would be very costly. Additionally, given Rigolet's load with a 720-kW peak, the community can sustain 2 x 800 kW wind turbines.
- Cartwright – Paradise River – 69 kV system, 47 km of transmission line.
  - It is recommended to connect Paradise River to another community due to its small load. Paradise River has a peak of approximately 75 kW and therefore would require a 100-kW turbine to achieve a penetration of approximately

50%. This would have a relatively high cost per kW and a high levelized cost of energy.

- The connection distance from Cartwright to Paradise River is comparatively short at only 47 km.

- Black Tickle to remain isolated.
  - Black Tickle was left isolated primarily due to the long transmission connection required (>210 km) and the need for a subsea cable. The subsea cable alone has an estimated cost of over $10 M, which is comparable to the cost of the renewable generation.
- Port Hope Simpson – Charlottetown – Norman Bay – St. Lewis – Mary's Harbour – 25 kV system, 220 km of transmission lines.
  - These communities are all generally located in the same area. Therefore, for a relatively modest transmission line length, 5 communities can be connected together.
  - Norman Bay and St. Lewis have relatively smaller loads; therefore, creating a centralized generation hub allows these communities to reduce diesel fuel consumption at a more modest cost than individual microgrids.
- L'Anse-au-Loop to remain isolated.
  - The transmission line required to connect L'Anse-au-Loop is very long at over 143 km. Additionally, L'Anse-au-Loop already forms a small microgrid with communities in Quebec and is served by low-cost hydro generation with a price of 13-15 cents/kWh. This hydro generation, provided by Hydro Quebec, already provides approximately 90% of their electricity. Therefore, unless there is a change in the supply agreement, it is recommended that L'Anse-au-Loop continue to operate with its current strategy.
  - It is also not recommended to install wind generation for L'Anse-au-Loop since the existing hydropower-based supply has a lower cost. However, if wind generation is desired, the configuration in Option 6 can be used.

The same strategies as used for Option 6 were used to estimate generation requirements for each microgrid. The forecasted peak and average demand for each community in 2024, as well as the peak load factor and generation requirements are presented in Table 3-23.

Table 3-23: Community Demand and Generation Requirements for Option 7

Community	Peak Demand (2024)	Average Demand (2024)	Peak Load Factor (2024)	Generation Requirements (2024)
Nain/ Natuashish	4,498 kW	2,436 kW	54%	21.3 GWh
Hopedale – Postville- Makkovik	2,697 kW	1,392 kW	53%	12.5 GWh
Rigolet	720 kW	349 kW	49%	3.1 GWh
Cartwright - Paradise River	995 kW*	529 kW	53%* (49% based on community peaks)	4.6 GWh
Black Tickle	279 kW	130 kW	46%	1.1 GWh
Port Hope Simpson – Charlottetown – Norman Bay – St. Lewis – Mary's Harbour	2,765 kW*	1,621 kW	59%* (45% based on community peaks)	14.6 GWh
L'Anse-au-Loop	5,846 kW	3,134 kW	54%	27.5 GWh
Total	17,800 kW*	9,589 kW	N/A	85.2 GWh

*adjusted for summer peaking communities

In this Option, each microgrid would have a centralized renewable generation installation with wind and energy storage, coupled with the existing diesel gensets serving the community. Again, a wind generation capacity of 3 - 4 times the average load was used to estimate the necessary capacity to achieve 50% renewable penetration. The energy storage system was either sized to cover the loss of a single turbine or the peak load of the community cluster microgrid, whichever was smaller.

The proposed generation configuration for each community is presented in Table 3-24. The generation requirements are slightly lower for Option 7 compared to Option 6, due to efficiencies gained by connecting the communities, particularly for Paradise River, and the Port Hope Simpson Microgrid in the south. It should be noted that the two 95 kW turbines are no longer required since these communities can be served by larger turbines which are centrally located. Additionally, in the north, with the connection of Hopedale, Postville, and Makkovik, larger wind turbines can be used to supply these communities. These larger turbines have lower overall levelized costs of energy due to economies of scale.

Table 3-24: Generation Requirements for Each Microgrid

Community	Peak Demand (2024)	Wind Generation	Configuration	Energy Storage
Nain/ Natuashish	4,498 kW	7,000 kW	2 x 3,500 kW	3,500 kW/1,750 kWh
Hopedale – Postville- Makkovik	2,697 kW	7,000 kW	2 x 3,500 kW	3,500 kW/1,750 kWh
Rigolet	720 kW	1,600 kW	2 x 800 kW	750 kW/375 kWh
Cartwright - Paradise River	995 kW*	2,400 kW	3 x 800 kW	800 kW/400 kWh
Black Tickle	279 kW	800 kW	800 kW	300 kW/150 kWh
Port Hope Simpson – Charlottetown – Norman Bay – St. Lewis – Mary's Harbour	2,765 kW*	7,000 kW	2 x 3,500 kW	3,500 kW/1,750 kWh
L'Anse-au-Loop	5,846 kW	0 kW	0 kW	0 kW
Total North	**7,915 kW**	**15,600 kW**	**4 x 3.5 MW, 2 x 800 kW**	**7,750 kW/ 3,875 kWh**
Total South	**9,885 kW***	**10,200 kW**	**2 x 3.5 MW, 1 x 800 kW**	**4,600 kW/ 2,300 kWh**
Total	**17,800 kW***	**25,800 kW**	**6 x 3.5 MW, 3 x 800 kW**	**12,350 kW/ 6,175 kWh**

* adjusted for summer peaking communities

Generation for L'Anse-au-Loop has not been included since the levelized cost of energy of a wind + battery system is greater than that of the hydro power supplied by Hydro Quebec. However, if NL Hydro elects to build wind + solar generation at L'Anse-au-Loop, approximately 14 MW of generation (4 x 3.5 MW turbines) is required and a 3.5 MW/1.75 MWh BESS to manage wind variability.

Again, in this scenario, the existing diesel generation would remain to provide 50% of the demand. As the gensets reach their end of life, it may make sense to have a centralized diesel power plant, co-located near the wind + storage. However, a tradeoff between reliability of supply to the communities and costs/operability is needed. As outlined in Section 8, there are pros and cons to decommissioning and relocating diesel power plants.

4. Diesel Fuel Reduction

Diesel fuel reduction is directly proportional to the renewable penetration.

For Options 1-3, it is assumed that 100% of the electricity required by the communities will be supplied by Churchill Falls or Muskrat Falls hydroelectric generating stations. In these cases, the existing diesel plants could be decommissioned. For L'Anse-au-Loop, the estimated reduction in diesel fuel was reduced, since approximately 90% (24,700 MWh per year) of the electricity is already supplied by Hydro Quebec, hydroelectric generation. In these cases, there would be no planned diesel fuel consumption.

For Options 4-7, approximately 50% of the electricity will be supplied by renewable generation. The most likely generation source will be wind. However, small solar may also be selected for communities in the south to compliment the wind generation, particularly for Cartwright, Mary's Harbour and Charlottetown which have summer peaks. For L'Anse-au-Loop in Option 4 & 5, it is assumed 50% of the generation would be supplied by the renewable generation, and 50% would be supplied by Hydro Quebec hydro. For Option 6 & 7, 90% of the electricity for L'Anse-au-Loop would continue to be supplied by Hydro Quebec.

As is the nature with intermittent renewable generation, the actual generation will vary year to year, with some years having a higher average percentage of the total electricity demand supplied by renewables and some years having a lower percentage.

Table 4-1: Estimated Diesel Fuel Reduction for Each Option

Option	Annual Diesel Reduction	Annual Diesel Fuel Reduction	Estimated Annual Savings
Option 1	59,950 MWh	17,500,000 L	$14,100,000
Option 2	59,950 MWh	17,500,000 L	$14,100,000
Option 3	59,960 MWh	17,500,000 L	$14,100,000
Option 4	31,350 MWh	9,100,000 L	$7,300,000
Option 5	31,350 MWh	9,100,000 L	$7,300,000
Option 6	28,600 MWh	8,300,000 L	$6,700,000
Option 7	28,600 MWh	8,300,000 L	$6,700,000

*genset efficiency and cost savings were estimated using a weighted average
*any savings associated with reduction in Voisey's Bay diesel consumption not considered

5. Operability Considerations

The following sections assess each Option from a generation supply and operability perspective. This will include considerations for operations and maintenance of the generation, substations, and transmission and distribution lines.

5.1 Option 1, 2 and 3

Options 1, 2, and 3 are fully interconnected systems, with all generation supplied to the communities via an extensive transmission network. Electricity will be sourced from Churchill and Muskrat Falls.

These large centralized hydro plants would be operated and maintained by local technicians and staff. Connecting the communities to these generators has negligible impact on operations, since Churchill Falls and Muskrat Falls are the major generation sources for the larger connected communities in Labrador. Therefore, the generators would be operated and maintained regardless of the interconnection strategy.

The major operability consideration for these Options is inspection and maintenance of the transmission lines and the substations.

Operations and maintenance of the northern transmission lines and substations, which are more remote would need to be considered. Technicians would need to do preventive maintenance on the substations by flying into each community. There is the potential that community members could be trained to do routine maintenance on this equipment. Where possible, substation and line equipment should be designed to be remotely operated from a central control room. Online condition monitoring and enhanced remote collection of asset condition and health indices through remote sensors may also reduce the cost of unplanned outages and increase reliability by providing an early warning of potential failures. On-site spares should be maintained for critical components to reduce the time required to obtain replacement parts.

Ice accretion on the transmission lines is likely the greatest concern for the northern loop, since there is not significant vegetation in the area. Strategies to manage ice accretion on the transmission lines should be considered to reduce outage risk and the need for technicians to maintain the lines.

For the southern radial transmission grid and substations, which are for the most part accessible by road, the operations and maintenance are more routine. Vegetation management would need to be planned for these transmission lines.

In the North, Nain is served through Voisey's Bay, therefore, in detailed design the configuration of the connection to Nain would need to be designed such that it can continue to be operational even if Voisey's Bay closed. In Option 1, Churchill Falls is also connected through Voisey's Bay. At this time, Voisey's Bay is planned to enter care and maintenance in the early 2030's; however, the mine life may be extended depending on the ore body and market. But NL Hydro should consider both options as a possibility.

If the mine enters care and maintenance, NL Hydro may need to take over the maintenance of the 69-kV substation at Voisey's Bay that is connecting both Nain and Voisey's Bay. In Option 1, this substation also connects Churchill Falls to the communities. An agreement would need to be reached with Vale on the approach to manage the maintenance of this substation. It is unlikely that NL Hydro would want to take ownership of all the power generating assets at Voisey's Bay; therefore, when the connection is designed, a strategy to continue to supply the communities without adding increased O&M burden to NL Hydro must be developed.

Though not specific to operability, there are also environmental impact considerations relating to building several hundreds of kilometers of transmission lines in an isolated region. Given the remote locations and relative wilderness of the areas, a thorough environmental assessment would need to be completed. As part of this project, a right-of-way needs to be cleared to bring the transmission lines from Churchill Falls and Happy Valley to the northern communities. When completing the assessment to select the right of way, applicable environmental studies may include:

- Assessment of the terrestrial environment for native fauna and flora for native species and the potential impacts;
- Assessment of migratory species in the region and potential impacts;
- Assessment on aquatic environment and fish habitat;
- Noise impact;
- Surface water & ground water impact;
- Impact of deforestation/clearing an old forest (more likely for the southern line); and
- End-of-life planning to return native species.

Additionally, consideration will need to be given to consultation of local residents and communities. Particularly if there are any lines or substations on community or privately-owned lands that are being used (this would require approval for usage, as well as approval for ongoing vegetation management, maintenance, etc.). An assessment of areas of cultural significance/heritage and an archeological assessment will need to be completed, to ensure the right of way selected does not impact the local first nations and community's heritage sites. This may also include appropriate permitting or approvals depending on local requirements.

The environmental impact of the northern transmission lines will be greater than the southern transmission lines, since the northern transmission lines will be built on pristine wilderness. By contrast, the southern transmission lines will be built along existing roadways, except to Black Tickle and Norman Bay. Therefore, existing information may be available on local species, flora, and cultural sites.

Nevertheless, for an extensive project such as these proposed interconnections, a thorough environmental assessment and community consultation will be required.

5.2 Option 4

For Option 4, the operability considerations primarily relate to the generation located in the north at or near Voisey's Bay. There are two considerations for this Option, first the impact of a centrally located generation source in the north, and second the usage of Voisey's Bay Mine's generation to manage wind variability.

Consideration must be given to the impacts of Voisey's Bay Mine reducing its operations and going into care and maintenance. Under this scenario, the diesel gensets may not be available to provide stabilization to the wind generation. Therefore, a battery energy storage system may need to be implemented at this time to ensure stable wind supply and reduce variability to the communities.

Additionally, if the wind generation is tied with Voisey's Bay, through the controls scheme and/or through the physical connection on the main 69 kV switchgear, upgrades may be required if the mine is closed. If this Option is selected, the proposed remaining life of the Voisey's Bay Mine should be discussed with Vale and considered when completing the detailed design to avoid the need for upgrades shortly after the project is completed. It may also be possible for NL Hydro to assume responsibility for operations and maintenance of this 69-kV substation if the mine is closed. However, the increased O&M costs and burden that NL Hydro will assume, as well as any environmental remediation burden, must be considered.

Another consideration for this design is the single generation hub in the north, which must be maintained as required. NL Hydro will need to determine the most appropriate strategy to support this generation, either through self-performing the maintenance (which could involve engaging in a service agreement with the vendor), engaging in a maintenance contract with staff at Voisey's Bay (may be beneficial if VB has its own wind farm), or entering into an agreement with an Independent Power Producer (IPP). Since the wind farm is centrally located, with large turbines, the maintenance activities will be less extensive and costly than the many small wind farms in Option 6.

Lastly, the impact of having the wind farm located in the north, several hundred kilometers away from the southern communities, which consume over 50% of the electricity, is important to consider. There will be significant losses and potential power quality impacts with this configuration. Since the turbines are in a single region, they will all experience the same windspeeds patterns– thus when windspeeds are low, all renewable generation in the large microgrid will be low. The diesel gensets within the communities will need to be controlled to cover the load during these periods of low generation.

There will also be the same operability considerations and requirements for the transmission lines and substations as in Options 1-3. Additionally, the same environmental assessment and impact studies would need to be completed for the transmission lines.

5.3 Option 5

Option 5 results in the formation of two large microgrids. The north microgrid has the generation centrally located at or near Voisey's Bay. The south microgrid has the generation centrally located, likely either at Port Hope Simpson or at Cartwright.

For the northern communities and microgrid, the same considerations as in Option 4 would apply relating to generation located at Voisey's Bay. Consideration must be given to how the wind generation is connected, and how a mine closure will impact the connection. Again, if Voisey's Bay Mine goes into care and maintenance, it is likely a battery will need to be connected to manage the wind's variability.

For the southern communities and microgrid, there are two potential locations for the generation, Cartwright or Port Hope Simpson. Both of these locations are accessible by road and are at or near larger communities which could support day-to-day operations. Again, to reduce the day-to-day operations efforts for NL Hydro, an agreement with an IPP to own, operate and maintain the generation may be preferred.

The transmission lines would also need to be maintained as outlined in Options 1-3. However, the major transmission connections to Churchill Falls and Happy Valley (nearly 850 km of 138 kV line) are not installed, thus this would significantly reduce efforts required for preventative maintenance on the transmission lines (line inspection, icing management and vegetation management).

Additionally, the same environmental assessment and impact studies would need to be completed for the transmission lines.

5.4 Option 6

Having the wind and storage generation in each community will lead to higher operations requirements. Though this equipment can be operated remotely, on-site inspections and maintenance will be required routinely, particularly for the wind turbines. Training local technicians to complete the routine maintenance and manage minor electrical faults and alarms will be highly beneficial.

NL Hydro may also elect to engage in power purchase agreements with one or more independent power producers (IPP). Under this strategy, NL Hydro would continue their operations of the diesel gensets as well as O&M for the distribution system; however, the IPP would be responsible for any maintenance on the wind turbines, alleviating the requirements for NL Hydro staff.

5.5 Option 7

Option 7 has 6 wind farms (7 if a wind farm is located in L'Anse-au-Loop). Compared to Option 6, there are fewer wind farms that need to be maintained. However, NL Hydro may elect to engage IPPs for this configuration in order to reduce the maintenance requirements.

NL Hydro will also need to maintain the transmission lines and substations in each of the connected communities. This would require annual inspection and preventative maintenance on the substations in 12 communities, 5 in the north and 7 in the south. Preventative maintenance would also need to be considered on the 474 km of 69 kV transmission lines and 220 km of 25 kV distribution lines. In the North, icing prevention would need to be considered, while the southern lines would need vegetation management to reduce the risk of outages.

Additionally, environmental assessment and impact studies would need to be completed for the transmission lines; however, the extent would be less due to the shorter length of transmission lines planned in Option 7.

6. Reliability Considerations

Reliability is a critical concern for all grid operations. Considering the remote locations and harsh climate for many of these remote communities, reliable delivery of electricity is essential, particularly in the winter months.

The System Average Interruption Frequency Index (SAIFI) and System Average Interruption Duration Index (SAIDI) data for the communities relating to supply is presented in Table 6-1, based on existing diesel generation.

Table 6-1: SAIFI and SAIDI for Isolated Communities in Labrador

System	Loss of Supply 2015-2019 Average	
	SAIFI (interruptions/ per customer)	SAIDI (hours)
Black Tickle	5.84	12.46
Cartwright	3.59	4.91
Charlottetown	4.36	4.22
Hopedale	5.37	2.79
L'Anse-Au-Loup	3.27	2.09
Makkovik	3.80	3.65
Mary's Harbour	4.55	1.65
Nain	1.59	2.02
Norman Bay	0.20	0.01
Paradise River	1.00	0.48
Port Hope Simpson	1.40	1.82
Postville	1.60	0.39
Rigolet	5.60	8.61
St. Lewis	1.40	2.28

The following sections will explore the reliability of the different Options. Since the distribution systems within each community will remain the same, the reliability of the community distribution system is not explored in this report.

6.1 Option 1

6.1.1 Northern Communities

In the north, where the communities are only accessible by boat or plane, the system is designed with high redundancy.

Each community is supplied by 2 transformers, which provide N-1 redundancy, such that each transformer is capable of serving the load on its own. Typical transformer availability is >98%. With 2 transformers, total system availability increases to >99.9%, which represents a low failure rate.

Similarly, with the loop design, serving communities from both Churchill and Muskrat Falls, 2 transmission line segments would need to be unavailable to result in an inability to supply. The likelihood of such an event occurring is relatively low except in extreme weather events.

The most vulnerable points in this design are the 361 km line from Churchill Falls to Voisey's Bay, the 188 km line from Happy Valley to Rigolet, and the 206 km line from Rigolet to Makkovik. These 3 long lines are the only connection to the hydro generation, therefore, an outage on more than one could significantly impact the ability to supply the communities between Makkovik and Nain.

Depending on where the outage occurs, it may be possible to serve some of communities with baseload generation (for heating in the winter), with the generation at Voisey's Bay until the transmission lines can be restored. However, this Option will no longer be available if Voisey's Bay closes.

Therefore, with this highly redundant design, the frequency of outages is likely to be quite low.

However, given the remoteness of these communities, the duration of any outages will likely be extended, particularly in the winter with fly in only access. For the most vulnerable and remote communities, it may be prudent to leave some of the diesel gensets operational to supply the communities in the event of an outage.

If this Option is selected, a detailed assessment of the outage risks, outage frequency, outage distribution throughout the year, and outage duration would be required. This information will be important to support the decision to decommission the diesel plants.

6.1.2 Southern Communities

The southern communities are served by a radial line, connecting all communities to Muskrat Falls and Churchill Falls. These communities have different considerations, since they are all accessible with year-round roads, and the transmission lines are for the most part along these roads (except Black Tickle and Norman Bay).

Since these communities are more accessible, outages can be restored more quickly. For the communities, a single step-down transformer was proposed with a centralized mobile transformer, likely located in Happy Valley. Again, with proper maintenance, the reliability of a transformer is very high, and the likelihood of a failure is low. A mobile substation is proposed, which can be deployed to the community in the event of a failure. The likelihood of two substations experiencing an outage is low. This mobile substation will need to have the ability to connect at both 69 kV and 25 kV on the primary winding.

Redundant parallel transformers are proposed in two places: The Muskrat falls intersection, where voltage is stepped down from 138 kV to 69 kV; and the junction at Port Hope Simpson, where voltage is stepped down from 69 kV to 25 kV and serves 4 communities. At these points, loss of supply would have a greater impact on the communities. Additionally, for these two points, the step-down configuration is unique, therefore, a mobile substation serving the other communities would not be able to serve these locations.

The transmission and distribution lines follow the access roads to each community, therefore inspection and maintenance of these lines will be easier, since technicians can access by car/truck. Similarly, if there is an outage on one of the lines that needs to be repaired, technicians can be dispatched and reach the site within several hours, likely resulting in shorter outage durations.

The most vulnerable point in this design is the 300 km line from Happy Valley to the Muskrat Falls Intersection. This long line is the only supply of hydro generation to these communities. An outage along this line would lead to an inability to supply any of the communities. There is also a long radial line to L'Anse-au-Loop; however, the vulnerability of this community is lower since it is also connected to a microgrid served by Hydro Quebec.

On the southern loop, the most vulnerable communities are Black Tickle and Norman Bay. These two communities are not accessible by road and require plane or boat access. Black Tickle currently experiences the highest outage rate and longest average duration of all the isolated communities.

Since these communities are not road accessible, the transmission line to serve the communities cannot follow a roadway. Therefore, if there is damage to the transmission line or the step-down transformer, restoration/repairs will likely take longer. Additionally, for Black Tickle, the proposed transmission connection involves a sub-sea cable of ~3 km in length to serve the community and a second step down transformer (25 kV to 4.16 kV) within the community. This adds a further failure mode. Appropriate design measures to protect the sub-sea cable from damage will reduce the risk. NL Hydro may consider introducing a second redundant stepdown transformer at the 25 kV to 4.16 kV level, since accessing the transformer on the island may take longer periods.

Since these communities are not as remote, keeping the diesel gensets on-site is less likely to be necessary. However, it may be prudent to do so in Black Tickle since it is the most vulnerable community under this design.

6.2 Option 2

6.2.1 Northern Communities

In Option 2, the long transmission line connecting Churchill Falls to Voisey's Bay is eliminated and replaced with a parallel line running from Muskrat falls via Rigolet to Voisey's Bay. Electricity from Churchill Falls will still serve the communities; however, it will be transmitted via the connection to Muskrat Falls and Happy Valley-Goose Bay.

This design keeps the two fully redundant transformers to serve each community, therefore, the reliability of the substations is fairly high, the same as Option 1.

Compared to Option 1, there are advantages and disadvantages for the transmission line from a reliability perspective.

This Option eliminates the long 360 km transmission line in north-western Labrador between Churchill Falls and Voisey's Bay. This is a highly isolated inland region which is only accessible by air. Therefore, in the event of an outage or damage to this transmission line, repairs will likely be complicated, take an extended period of time, and be costly.

By contrast, having the parallel lines along the same right of way will result in the lines being more accessible from the coast. Additionally, since they are closer to the communities, technicians may be able to respond to faults more quickly.

However, this configuration is likely more vulnerable to extreme weather events, since both lines are along the same right of way. If there is an extreme storm, it has a higher probability to take both lines down. Alternatively, if the lines use the same poles/towers, damage to the pole/tower would likely lead to both lines experiencing an outage. This would cut off access to all communities north of the outage. If both lines are down, it may be possible for Voisey's Bay to serve the baseload generation for the communities north of the outage until the transmission lines have been repaired. However, this Option will no longer be available if Voisey's Bay closes.

The most vulnerable points in this design are the parallel 188 km line from Happy Valley to Rigolet, and the parallel 206 km line from Rigolet to Makkovik. These 4 parallel, long lines are the only connection to the hydro generation, therefore, an outage on more than one could significantly impact the ability to supply the communities between Makkovik and Nain.

Given the remoteness of these communities, if both lines are damaged, the outage period will likely be extended due to the time it will take for technicians to access the site. If there are particularly vulnerable communities, it may be prudent to keep one or more diesel gensets on site as backup in the event of an extended outage in the winter.

6.2.2 Southern Communities

The configuration in the south is the same as Option 1 and is expected to have the same reliability levels.

6.3 Option 3

6.3.1 Northern Communities

In Option 3, a single transmission line runs from Muskrat Falls in the south to Voisey's Bay in the north. The transmission line connecting Churchill Falls to Voisey's Bay in Option 1, and the redundant parallel line in Option 2 are not included in this Option.

Option 3 continues to retain the 2 transformers to serve each community, thus does not impact substation reliability compared to Options 1 and 2.

Having the single radial line leads to lower reliability compared to the other two Options. A single outage along the line will lead to interruption of supply for the communities north of the outage. Given the remoteness of the site, if the outage requires technicians to repair any damage, the duration of the outage may be extended.

The most vulnerable points in this design are the 188 km line from Happy Valley to Rigolet, and the 206 km line from Rigolet to Makkovik. These 2 long lines are the only connection to the hydro generation, therefore, an outage on more than one could significantly impact the ability to supply the communities between Makkovik and Nain.

One option NL Hydro may consider in this configuration is entering into an agreement with Voisey's Bay. The onsite generation could be used to serve communities north of the transmission line outage until the transmission line can be repaired. The ability to leverage Voisey's Bay is more important in this configuration due to the higher vulnerability.

A second consideration may be to leave one or more gensets within each community, which can act as backup in the event of an extended outage, particularly in the winter. The gensets could also serve to support power quality, particularly at the end of the radial line, a long distance away from generation.

6.3.2 Southern Communities

The configuration in the south is the same as Options 1 and 2 and is expected to have the same reliability levels.

6.4 Option 4

The substation transformer design of Option 4 is the same as Options 1-3, with two substation transformers supplying the northern communities, at the 138 kV to 69 kV stepdown and at Port Hope Simpson. Each of the remaining southern communities is supplied by a single stepdown transformer.

Under this configuration, any outage along the line will result in a loss of renewable generation supply to the communities south of the outage. Depending on the location of the outage, the accessibility of the line will determine the expected length of the outage.

In the current cost estimate, it is assumed that all communities will keep their existing generation. Therefore, this generation would likely be running or could be started up in a short period in the event of an outage, adding higher reliability and reducing the duration of any outages.

However, if NL Hydro elects to go with a centralized generation hub when the gensets are replaced, this increases the vulnerability of the communities to outages. It may be more prudent to have more diesel generation hubs, particularly in the south, which can continue to operate and serve the nearby communities in the event of a transmission line outage. This is also beneficial from a power quality perspective.

Particularly vulnerable communities are Cartwright, the communities in the Port Hope Simpson region, and Mary's Harbour. Since L'Anse-au-Loop is connected to Hydro Quebec, it is less likely the community will experience a complete outage since there are multiple generation options which can serve the load.

Lastly, having all of the generation in a single region will mean that when windspeed is low in the north, renewable generation will be low and there will be a higher demand on diesel generation. Options 5, 6, and 7 all have renewable generation distributed throughout Labrador to varying degrees, and thus will not be as severely impacted by variation in windspeed in a single region.

6.5 Option 5

6.5.1 Northern Communities

For the northern communities, the transmission and substation reliability would be comparable to Option 4. Having the centralized generation hub at Voisey's Bay leaves the communities farthest from Voisey's Bay (Makkovik and Rigolet) at the highest vulnerability, since an outage on any one of the northern 4-5 transmission segments would result in an inability to service the community with wind generation.

In the current design, with the existing diesel generation maintained in the communities, even if there is an outage, the diesel generation can be started up to supply power relatively quickly (likely in less than 30 min), reducing the impact of an outage and the duration.

In this configuration, with wind generation, there is a supply risk that must be considered. Due to the intermittency of wind, there will be extended periods of time where windspeeds will be low and generation will be low. Ensuring there is enough diesel generation within the communities to supply the basic loads (heating, cooking, etc.) will be important to ensuring reliable supply. At this time, it is assumed the communities would continue to operate with the gensets in each community to serve the load when wind generation is low. However, since the communities are connected, it may be possible to have more centralized hubs for diesel generation. As with Option 4, centralizing the generation reduces the reliability and increases the risk of outage. A tradeoff between cost, operability, and reliability will be required when the gensets reach end of life, if this Option is selected.

6.5.2 Southern Communities

There are two potential locations for wind generation to supply the southern microgrid, Cartwright and Port Hope Simpson.

If the generation is located at Cartwright, the reliability considerations are similar to the North, since the generation would be located at the end of a radial transmission line. However, since the transmission lines are accessible via road, restoration will be faster and thus outage duration will likely be on average shorter.

If the generation is located at Port Hope Simpson, it is in a more centralized connection point, with 4 radial lines exiting from the generation hub. This leads to higher reliability, since a transmission line outage will only impact 2-3 communities at any given time. If the windspeeds are sufficient in the region, locating the generation at Port Hope Simpson has a distinct advantage from a reliability perspective.

As with the North, there is a supply risk due to the inherent variability of wind generation. However, ensuring there is sufficient thermal + storage to supply the load will mitigate this risk.

Furthermore, maintaining diesel generation within the communities reduces reliability concerns, since the gensets can be ramped up in the event of an outage in a relatively short period.

6.6 Option 6

Option 6 assesses having microgrids with wind + storage + thermal generation to supply each community individually. Therefore, within this configuration, there are no reliability considerations from a transmission, distribution or substation perspective.

However, since each community remains fully isolated, there continues to be a reliability concern from a supply perspective. By adding the wind + storage, there is additional generation within each community, thus reducing the impact of one or more genset outages. However, since the communities continue to remain isolated, they cannot support each other from a supply perspective. Therefore, if there are low windspeeds, low diesel storage, or performance issues with the gensets or the wind turbine, there may be periods with low supply. Having the redundant generation and energy storage in each community reduces this risk. Additionally, appropriate controls and energy storage is required to ensure this reliability to maintain seamless power generation while managing wind variability.

6.7 Option 7

Option 7 is designed around several small microgrids connecting 2-5 communities together. In this Option there are short transmission lines connecting the communities. The longest transmission line is connecting Nain to Natuashish at 145 km, as well as Hopedale to Postville at 142 km.

This Option has the benefit of allowing for centralized larger wind farms, to reduce the capital cost of generation and connecting the communities to reduce curtailment and improve reliability. By connecting the communities, the diesel generation in each of the communities can support the other communities if there is a major outage of diesel units within the communities. Therefore, this adds reliability by having distributed generation within the communities, but connecting the communities allowing them to support each other if there is low generation capability in one community for any number of reasons.

Nain to Natuashish: For the Nain to Natuashish microgrid, wind generation will likely be located within the Nain community, and supplied to Natuashish via a 69-kV transmission line. The gensets will remain in the communities – particularly since NL Hydro does not own the gensets or electrical infrastructure in Natuashish. In this configuration, there is the risk that the 145 km 69 kV line has an outage, and wind generation cannot be transmitted to Natuashish; however, since it is expected that there will be gensets in Natuashish, the risk of an extended outage is relatively low.

Since the communities are connected, if there is an outage in either the Nain or Natuashish diesel plants, the diesel gensets in the other community can be used to support the load to reduce the duration/impact of an outage.

Hopedale, Postville, and Makkovik: For the Hopedale – Postville – Makkovik microgrid, the wind + storage will likely be located in Hopedale or Makkovik, since they are both larger communities on the coast with strong wind resources. The main reliability risk in this configuration is an outage along the 220 km radial transmission connection. Since the wind will likely be located in one of the communities at either end of the line, an outage along the line would result in an inability of wind generation to be supplied to one or both of the communities (depending on if one or both segments are out). However, keeping the gensets within the communities provides a backup to increase reliability and reduce the duration of any outages.

If a centralized generation hub is designed in the future, the reliability of the system would be lower, since any outage on the transmission line would result in a loss of generation. It would be prudent to keep the gensets in both Hopedale and Makkovik, on each end of the radial line, since both transmission line segments would need to experience simultaneous outages to lose supply to Postville.

The other consideration is loss of supply. Again, by connecting the communities, the diesel gensets in all three communities can support each other in the event of an outage. This will likely reduce the duration of any diesel genset or wind supply related outages.

Cartwright and Paradise River: The Cartwright and Paradise River microgrid is expected to have wind generation in Cartwright since this is a larger community and along the coastal region. The reliability considerations are the same as the Nain-Natuashish microgrid.

However, in this case, since Paradise River is a relatively small community, connecting to Cartwright will likely bring added reliability, since the larger, more reliable gensets in Cartwright can be used to support the load in Paradise River.

Port Hope Simpson, Charlottetown, Norman Bay, St. Lewis and Mary's Harbour: This 5 community microgrid forms the largest of the microgrids in Option 7. This microgrid is centralized around Port Hope Simpson with 3 radial lines to connect the other communities.

From a reliability perspective, locating the wind + storage generation at Port Hope Simpson provides the highest reliability. In this configuration, each community is served by a radial line from Port Hope Simpson, except Norman Bay, which is served through Charlottetown. An outage on any one of these lines (except Port Hope Simpson to Charlottetown) would only result in an inability of wind to be supplied to a single community, rather than multiple communities, improving the overall system reliability.

Given the relative proximity of the communities in the proposed microgrid, the retirement of gensets in the respective communities may be possible without an adverse reliability impact. Such determinations may be made on the basis of more detailed reliability analysis beyond the scope of this investigation.

Rigolet, Black Tickle, and L'Anse-au-Loop will continue to remain isolated grids with diesel and wind (or hydro for L'Anse-au-Loop). The reliability within these communities would be similar to the current reliability with a hybrid microgrid system. Appropriate controls and energy storage are required to ensure this reliability, and to maintain stable power generation while there is wind variability.

Option 7 provides a blended solution, adding reliability to the network and grid stability by connecting a few communities. However, it does not present the same risk as a large centrally located renewable generation hub or hydroelectric plant serving the communities along long radial lines, where the outage of one of the main lines could lead to a widespread extended outage.

7. Cost Estimates

7.1 Unit Cost Review for NL Hydro Interconnection

High level unit costs for major transmission/distribution system components was estimated at a class 5 level, based on information provided by NL Hydro, published information and inputs from subject matter experts. Using this unit cost information, capital cost estimates were developed for each of the 7 Options. Further details on the capital cost estimates can be found in Appendix A.

7.1.1 Information Sources for Capital Costs

Unit costs for transmission and distribution components were based on several information sources namely:

- NL Hydro high-level cost estimates, as provided in the February 17, 2016 memo "Labrador Interconnection – Preliminary Study – Cost Estimate Update. The estimates provided in this report are summarized in Table 7-1.

Table 7-1: Capital Cost Estimates from NL Hydro's Interconnection Study in 2016

System Component	2016 Value
138kV OH Transmission Line	$995,000/km
69kV OH Transmission Line	$765,000/km
25kV OH Distribution Line	$197,000/km
HV terminal stations	$10,100,000
Distribution Stations	$7,100,100
Mobile Substations	$4,600,000
Mobile Substation (Lab South)	$5,100,000
69kV Line tap	$2,500,000

- Report titled "Unit Cost Estimates for Transmission Lines and Facilities in Northern Ontario and the Far North", prepared by SNC Lavalin for the Ontario Power Authority, October 18, 2011.[4] The costs estimated in this report reflect installation conditions and infrastructure types which are expected to be similar to the NL hydro interconnection project. For the northern loop, the "Far North" cost basis was used, which assumes temporary access roads required for 100% of route and heavy brushing for 75% of route. For the southern loop, the "Northern Ontario" cost basis was used, which assumes 50% of route requires installation of temporary access roads, and 50% heavy brushing of line routes. All costs include overhead and contingency. Land acquisition / ROW land rental costs have not been included in these estimates.

- In the case of the 25 kV submarine connection, the published cost data for the Bell Island Submarine Cable Replacement (2013) was used as a reference given the geographic proximity and similar interconnection voltage and length.[5]

- Transmission Cost Estimation Guide, MTEP19, Midwestern Interconnection System Operator, 2019[6] was used for cost references for reactive power compensation components including capacitor and inductors.

- Equipment vendors and internal subject matter experts were also consulted to establish budgetary costs.

[4] http://www.ieso.ca/-/media/Files/IESO/Document-Library/regional-planning/North-of-Dryden/App-1-1-3-Transmission-Unit-Cost-Study-SNC-Lavalin.pdf?la=en

[5] http://www.pub.nf.ca/applications/NP2014Capital/NPCBSUPP2014/BellIslandSubCable/application/Application-ApprovaltoReplacetheBellIslandSubmarineCable-2013-12-09.pdf

[6] https://cdn.misoenergy.org/20190212%20PSC%20Item%2005a%20Transmission%20Cost%20Estimation%20Guide%20for%20MTEP%202019_for%20review317692.pdf

7.1.2 Substation Costs

The following summarizes the high-level substation cost estimates proposed for the study. Base costs cited in SNC Lavalin, 2011 have been adjusted based on the following assumptions:

- Reported costs were escalated by 10% based on inflation (+20%) and the expected construction cost differential between Ontario and NL (-10%).
- Reported costs were provided for some representative substation configurations at voltage levels including 220/115 kV, 115/44 kV, 115/25 kV, 44/25 kV. The reported costs the were adjusted based on:
  - Number of transformers (based on incremental costs as reported, including overhead and contingency)
  - Number of line terminations (based on incremental costs as reported, including overhead and contingency)
  - Voltage levels
  - Power capacity (costs were adjusted based on the differences in substation capacity based on SME input)

Mobile substation costs were based on NL Hydro's estimate, escalated for inflation to reflect costs in 2020 dollars at an inflation rate of 1.7% per year.

Table 7-2 provides a summary of the cost estimates for substations based on the assumptions above.

Table 7-2: Estimated Substation Costs for each Community

	Station Name	Description	No. of line terminations (Primary)	No. of line terminations (Secondary)	Capital Cost Estimation
Northern Loop	Churchill Falls	230 kV to 138 kV; 1 x 37.5/50/62 MVA	1	1	$7,500,000
	Nain	25 kV to 4.16 kV; 2 x 3.75/5/6 MVA	2	1	$4,000,000
		69 kV to 4.16 kV; 2 x 3.75/5/6 MVA	2	1	$5,000,000
	Natuashish	138 kV to 25 kV; 2 x 3.75/5/6 MVA transformers	2	1	$9,100,000
		69 kV to 25 kV; 2 x 3.75/5/6 MVA transformers	2	1	$7,700,000

	Hopedale	138 kV to 4.16 kV; 2 x 2/2.7/3.3 MVA transformers	2	1	$6,300,000
		69 kV to 4.16 kV; 2 x 2/2.7/3.3 MVA transformers	2	1	$5,000,000
	Postville	138 kV to 4.16 kV; 2 x 1.5/2/2.5 MVA transformers	2	1	$5,900,000
		69 kV to 4.16 kV; 2 x 1.5/2/2.5 MVA transformers	2	1	$4,700,000
	Makkovik	138 kV to 4.16 kV 2 x 1.5/2/2.5 MVA transformers	2	1	$5,900,000
		69 kV to 4.16 kV 2 x 1.5/2/2.5 MVA transformers	2	1	$4,700,000
	Rigolet	138 kV to 4.16 kV 2 x 1.5/2/2.5 MVA	2	1	$5,900,000
	Mobile Substation				$5,000,000
Southern Loop	**Muskrat Falls Intersection**	138 kV to 69 kV; 2 x 10/13.3/16.6 MVA	2	1	$9,800,000
	Paradise River*	69 kV to 4.16 kV; 1 x 1.5/2/2.5 MVA	1	1	$3,700,000
	Generation Substation	15MVA, 69kV - Expansion to substation at Port Hope or Mary's Harbour to allow for generation	1	1	$1,800,000
	Cartwright	69 kV to 4.16 kV; 1 x 1.5/2/2.5 MVA	1	1	$3,700,000
	Black Tickle I	69 kV to 25 kV; 1 x 1.5/2/2.5 MVA	1	1	$6,100,000
	Black Tickle II	25 kV to 4.16 kV; 1 x 1.5/2/2.5 MVA	1	1	$2,400,000
	Port Hope Simpson	69 kV to 25 kV - 12.5 kV; 2 x 2/2.7/3.3 MVA	2	2	$7,400,000
	Charlottetown*	25 kV to 4.16 kV; 1 x 2/2.7/3.3 MVA	1	1	$2,800,000
	Norman Bay	25 kV to 4.16 kV; 1 x 1.5/2/2.5 MVA	1	1	$2,400,000
	St. Lewis	25 kV to 12.5 kV; 1 x 1.5/2/2.5 MVA	1	1	$3,400,000
	Mary's Harbour*	69 kV to 4.16 kV; 1 x 1.5/2/2.5 MVA	1	1	$3,700,000

	L'Anse-Au-Loop	69 kV to 25 kV; 1 x 5/6.7/8.3 MVA	1	1	$6,700,000
	Mobile Substation				$5,500,000

*It is assumed that the transmission/distribution line is tapped to enter these substations with a single termination.

Cost for reactive power compensation elements was also estimated, based on the following assumptions:

- Costs reported in the MTEP19 report were used, escalated for inflation and the USD/CAD exchange rate.
- A 25% cost increase was applied to reported values to reflect the remote location and installation conditions.

The installed unit costs for reactive power compensation components is summarized in Table 7-3 below.

Table 7-3: Unit costs for reactive components

Device Type	Voltage Level	Variable Costs (per MVAR)	Fixed Costs (per device)
Capacitor	69/138kV	$17,000	-
Reactor/Inductor	69/138kV	$23,000	-
D-Statcom	69/138kV	$214,000	-
Circuit Breaker	69kV	-	$111,000
	138kV	-	$160,000

7.1.3 Transmission and Distribution Lines Costs

The following summarizes the high-level unit cost estimates proposed for transmission / distribution lines included in the study. Base costs cited in SNC Lavalin, 2011 were reported for 230 kV, 115 kV, 44 kV and 25 kV lines with various construction types. Costs for line types considered in this study were based on reported costs for 115 kV (H-frame wood poles, 477 kcmil, single circuit) , 44 kV (single wood pole, 336 kcmil, single circuit) and 25 kV (wood poles, 3-phase, single circuit) lines in SNC, 2011, and were modified based on SME input in consideration of differences in conductors, component ratings, spacing etc.

- 138 kV line costs were estimated 30% higher than stated costs for 115 kV lines in SNC, 2011.
- 69 kV TL221 lines were estimated 40% higher than stated costs for 44 kV lines in SNC, 2011.

- 69 kV TL261 lines were estimated 15% lower than stated costs for 115 kV lines in SNC, 2011.

The estimated unit costs for different transmission and distribution lines included in the study are summarized in Table 7-4. Line tap costs have been assumed to be incremental costs incurred as part of the overall line construction.

Table 7-4: Summary of Unit Costs for Transmission and Distribution Systems

	Run	Voltage	Conductor Size	Construction	Cost per km
Northern Loop	Transmission Lines in North, no road access so temporary road required	138 kV	559 kcmil, AAAC	H-Frame wood	$850,000
	Distribution line to Nain, no road access so temporary road required	25 kV	4/0 AASC	Single wood pole	$230,000
Southern Loop	Transmission Lines in South, existing road access. Lines follow existing roadways	138 kV	559 kcmil, AAAC	H-Frame wood	$680,000
		69 kV*	559 kcmil, AAAC	H-Frame wood	$580,000
		69 kV*	267 kcmil, ASCR	Single wood pole	$290,000
	Undersea cable to Black Tickle	25 kV	#1 XLPE sub cable	Submerged cable / ducted cable	$3,500,000
	Distribution lines South, following existing roadways	25 kV	4/0 AASC	Single wood pole	$190,000
	Line Tap (Cost per tap)	69kV	N/A	N/A	$2,500,000
		25kV	N/A	N/A	$1,700,000

* The main 69 kV transmission line running between the Muskrat Falls Intersection and L'Anse-au-Loop is using Darien AAAC 559 kcmil Conductors, while the 69 kV lines servicing Paradise River, Cartwright, and Black Tickle is using a Partridge ACSR 267 kcmil Conductor due to the lower current. These were assumptions made by NL Hydro in their original study.

7.1.4 Generation Costs

The generation cost estimates are based on recent quotations Hatch has received for similar projects, benchmark pricing, and Hatch's experience relating to remote power supply.

In this assessment, there are three wind turbine size ranges used: 100 kW, 800 -1000 kW and 3,000-4,200 kW. The baseline sizes used in the model were 95 kW, 800 kW and 3,500 kW. As the turbine size increases, the unit costs decrease as a result of efficiencies gained by having a large turbine. Additionally, unit costs decline as a function of the number of turbines installed due to economies of scale.

As the larger communities are accessible by barge, it is likely possible to bring a 3.5 MW turbine to the site on a barge. The parts would be placed on the barge (some on trucks on the barge) and brought to the community. At this time, they would be transported to the project site.

As individual projects evolve, a detailed logistics study will be completed to determine the detailed approach to supplying the turbines. However, at this time, there is no major concern regarding supply of a 3.5-4 MW turbine to the barge accessible communities.

The range of CAPEX used in this assessment of the wind turbine generation is presented in Table 7-5. As shown, the unit cost per kW can be quite high for a single small 100 kW turbine; however, declines considerably as turbine size is increased.

Table 7-5: Unit CAPEX and OPEX Costs for Various Turbine Sizes and Number of Turbines

Turbine Size	CAPEX (1 turbine)	CAPEX (5 + turbines)	OPEX Range
100 kW turbines	~$25,000 /kW	~$10,000 /kW	2-3.5% of CAPEX
800-1,000 kW turbines	~$7,000 /kW	~$6,000 /kW	2-3.5% of CAPEX
3,000 – 4,200 kW turbines	~$5,000 /kW	~$3,500 /kW	2-3.5% of CAPEX

The other two key generation components for these Options are the energy storage system and the microgrid controller. The estimated capital cost for energy storage systems are presented in Table 7-6 and the microgrid controller is presented in Table 7-7.

As seen with the wind turbines, the unit cost for energy storage components declines as the size increases. For the Options presented above, with 40-50% wind penetration, a 30 min battery is proposed to cover the short-term variability of wind generation until a genset can be started. There is a higher unit cost per kW for this technology due to the specialized nature of high power (discharge duration <1 hr.) batteries; however, a 30 min battery will have a cheaper total CAPEX compared to a 1+ hr. battery of the same power rating.

Table 7-6: Estimated Unit CAPEX and OPEX Cost based on energy storage sizing

Size	Estimated Unit CAPEX	OPEX
100 kW/50 kWh	$8,900/kW	$60,000/yr + $2.50/kWh installed
500 kW/250 kWh	$3,200/kW	$60,000/yr + $2.50/kWh installed
1,000 kW/500 kWh	$1,940/kW	$60,000/yr + $2.50/kWh installed
2,500 kW/1,250 kWh	$1,150/kW	$60,000/yr + $2.50/kWh installed
3,500 kW/1,750 kWh	$970/kW	$60,000/yr + $2.50/kWh installed

Table 7-7: Capital Cost for Microgrid Controller

Component	CAPEX
Microgrid Controller	$400,000 /lot

7.2 Operating Costs

7.2.1 Lines Operations & Maintenance Costs

Hatch used the operating cost estimates provided by NL Hydro in its CBA – Southern Lab Interconnection cost estimation worksheet as well as internal subject matter experts to derive general factors for annualized operating costs, assuming a 40-year operating timeframe.

Costs for 25 kV interconnection were based on the NL Hydro estimate, including per km estimates for:

- Vegetation management (tree-trimming at 5-year intervals, spray treatment at 10-year intervals);
- Structure inspection (3 times within the initial 20-year period);
- Structure replacement (assumed no replacement within the 20-year period);
- Infrared inspection (every 4 years);
- Voltage regulator readings, inspection and preventative maintenance (on a monthly, annual and 5-year basis respectively); and
- Switch preventative maintenance (every 5 years).

Based on the above, the preventative maintenance costs were estimated to be on the order of 0.4% of the estimated capital costs. To account for some potential replacement cost or reactive maintenance, 0.6% of CAPEX was used as the basis for estimating operating costs in the southern interconnection region. To reflect the more remote and potentially harsher conditions in the north, this factor was increased to 0.75% of CAPEX. The capital costs are already assumed higher in the northern region.

For transmission voltages, O&M costs are assumed to be lower as a % of CAPEX as both capital costs are higher, and due to lower requirements for vegetation management, and reduced maintenance of components such as voltage regulators. Values of 0.4% for the southern region and 0.5% for the northern region are assumed. These values are consistent with the order of magnitude of operations and maintenance costs reported for overhead transmission lines in other sources; however, these have been adjusted to reflect the challenging maintenance conditions and environment.[7]

7.2.1.1 40-year extension

In addition to routine maintenance, asset replacement due to failures or condition has been assumed as an average annual percentage of CAPEX. This was determined by modelling the expected failure/survival rates. It is assumed that line replacement rates will be determined by the expected lifespan of the wood poles. A 60-year expected lifespan of wood poles has been assumed based on typical values for northern latitudes. Based on an assumed degradation curve illustrated in Figure 7-1, this implies a replacement of approximately 20% of lines within the first 40 years. The annual replacement rate will increase over time, with the majority of replacement occurring in the latter years of this time period, however for simplicity a constant replacement rate is assumed.

[7] Parsons Brinkerhoff, Electricity Transmission Costing Study, 2012. Available at: https://www.theiet.org/impact-society/factfiles/energy-factfiles/energy-generation-and-policy/electricity-transmission-costing/. Annual O&M reported as lifetime costs represent 0.2-0.3% of capital costs, as annualized costs.

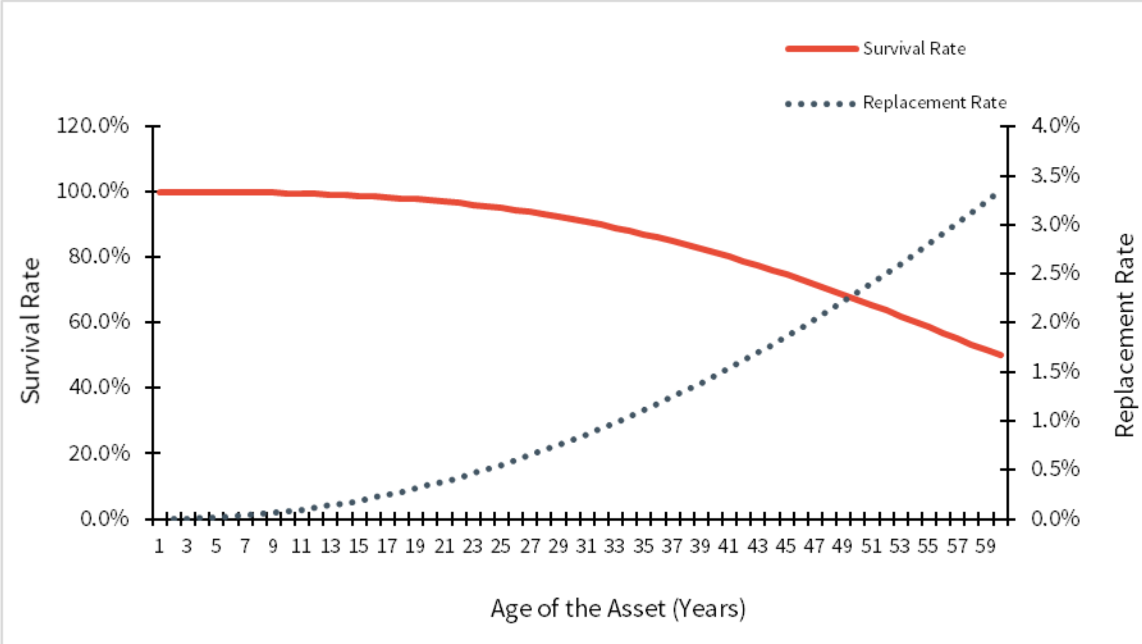


Figure 7-1: Expected Survival/Replacement Rate of Lines

To account for some potential replacement cost or reactive maintenance over a 40-year period, the operating costs for distribution lines were increased to 1.0% of CAPEX in the southern interconnection region and 1.15% of CAPEX in the northern region.

For transmission voltages, values of 0.8% for the southern region and 0.9% for the northern region are assumed for a 40-year period.

7.2.2 Substation Operations & Maintenance

Operations and maintenance of air insulated substations involves routine inspections, preventative maintenance and corrective maintenance including:

- Annually:
  - Visually inspect all wiring, insulators, connectors, busbars;
  - Inspection of circuit breakers, switches, disconnects;
  - Inspection of transformers;
  - Inspection of load tap changers, capacitor/inductor banks;
  - Inspection of relays;
  - General site inspection and maintenance (snow clearing, vegetation control etc.);

- Infrared thermography inspection; and
- Inspection of D-Statcom air filters.

- Periodic (e.g. every 5 years):
  - Transformer maintenance including oil vacuum and filtering;
  - Functional testing of all alarms and controls;
  - Check and clean insulators, application of high voltage insulation coating as necessary;
  - Testing of grounding system;
  - Maintenance and testing of circuit breakers, switches, disconnects;
  - Maintenance of load tap changers, capacitor/inductor banks;
  - Wiring insulation testing;
  - Resistance testing of joints and connections;
  - Oil insulation testing; and
  - Inspection and testing of D-Statcom.

Generally, maintenance costs are expected to increase with the size of the substation, and number of components. Access and serviceability are also factors that will impact maintenance costs. As a high-level estimate, a % of capital cost can be considered as indicative of expected operations and maintenance costs.

For the purposes of this study a factor of 0.3% and 0.4% of CAPEX has been assumed for annual OPEX costs including the above activities for the southern and northern regions, respectively. These costs do not include major capital replacement of equipment, as this is not expected within the time frame of the 20-year study.

7.2.2.1 40-year extension

It is assumed that replacement rates for substations will be determined by the expected lifespan of major components such as transformers and switchgear. A 40-year expected lifespan for major substation equipment has been assumed. Based on the degradation curve illustrated in Figure 7-2, this implies a replacement of approximately 50% of substation equipment within the first 40 years. The annual replacement rate will increase over time, with the majority of replacement occurring in the latter years of this time period, however for simplicity a constant replacement rate is assumed. It is expected that replacement costs to upgrade substation equipment will be approximately 50% of original capital costs.

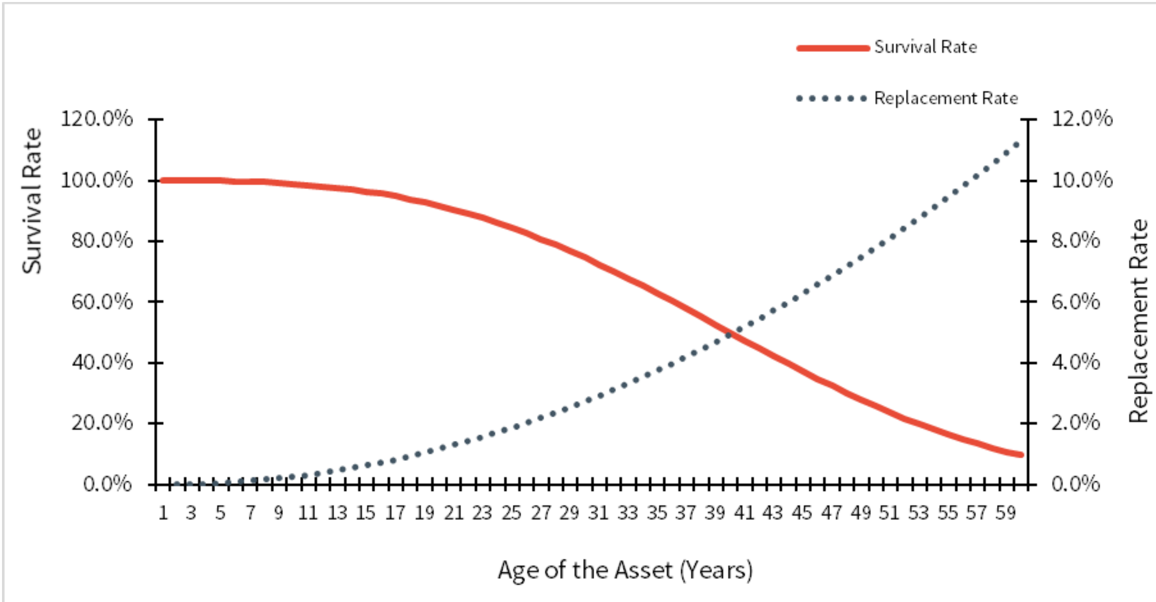


Figure 7-2: Expected Survival/Replacement Rate of Substations

Based on the above, the average annual replacement costs for substations over a 40-year period has been estimated at 0.9% of CAPEX (50% of the average replacement rate of 1.8%). Total annual OPEX for substations including both regular O&M and equipment replacement has been assumed as 1.2% and 1.3% of CAPEX for the southern and northern regions respectively.

7.2.3 System Losses

System losses are costs associated with the inefficiencies of the power delivery system. Transmission system losses is a continuously varying parameter, which depends on several factors including loads, line voltage, line loading and line resistance. In this subsection, the transmission line losses for relevant Options are assessed and annual cost of losses are determined. The analysis is particularly relevant for Option 1-5 where there are considerable transmission lengths to serve the communities.

Various methods are used in the industry to determine transmission losses including peak load level analysis, multiple load level, seasonal loading, and hourly loading scenarios with each having their own advantages and limitations. The approach used in this study involves assessing the transmission line losses at peak load condition and utilizing annual load factor to determine the average annual energy losses. Transmission line losses are calculated in PSSE by running a peak system load flow for Options 1-5. The annual load factor is determined by dividing the total annual energy consumption (MWh) of the communities by the peak load of the subsystem (MW) times 8760 hours.

NL Hydro has indicated that their total marginal system losses are $7,777.86/kW over 30 years at a rate of 5.65%. This is comprised of $4,836.82/kW for Marginal Capacity Losses and $2,941.04/kW for Load Energy Costs. This value was used to estimate the cost of transmission losses over 30 years and then the annualized cost of losses for each Option.

The line losses, total cost and annualized cost are presented in Table 7-8. The line losses and associated cost varied among different Options. The likely causes of variation is different system design, transmission line lengths, line flows and line voltages. As expected, the line losses and associated cost of losses for Options 1-3 with long transmission connections is considerably greater than Options 4 and 5 which eliminate the long connections from Churchill and Muskrat Falls. It is worth noting that optimizing existing controls for transformers tap and switched shunt elements could reduce line flows and hence minimize the transmission losses in Options 1-3.

Table 7-8: Estimated System Losses and Associated Annual Costs

Option	Transmission Losses at Peak Demand	Transmission Losses at Average Demand	Total Losses Cost over 30 years	Annualized Cost of Losses
Option 1	7.8 MW	5.3 MW	$40.9 M	$2.9 M
Option 2	11.9 MW	8.0 MW	$62.2 M	$4.4 M
Option 3	25.2 MW	17.0 MW	$131.9 M	$9.2 M
Option 4	3.1 MW	2.1 MW	$16.2 M	$1.1 M
Option 5	1.4 MW	1.0 MW	$7.6 M	$0.5 M

7.2.4 Generation Operating Costs

The estimated annual operating costs for the three different generation sources are presented in Table 7-9.

For diesel gensets, since these engines are in more remote locations and are older engines, it was assumed that there would be a higher average operating cost. The estimated O&M was set at $0.11/kWh generated.

An additional $0.035/kWh generated was added to the O&M to cover major engine overhaul costs, resulting in a total of $0.145/kWh for the 40-year study period.

For wind generation, the total O&M costs are largely based on the size of the wind farm. Larger wind farms, with 5 or more turbines will have lower operated costs as a percentage of total CAPEX, since the service costs can be distributed between many turbines. For this model a range of 2% - 3.5 % of CAPEX/yr was used for the OPEX for wind. For wind farms of 5 or more turbines, 2% of CAPEX/yr was used. This was increased linearly to 3.5% of CAPEX/yr for a single turbine installation.

For batteries, the typical operating costs are based on annual (or bi-annual) vendor site visits for preventative maintenance and an allocation of approximately $2.50/kWh installed. An allocation of $60,000 per year was included for vendor site visits and preventative maintenance.

Table 7-9: Estimated annual operating costs for generation.

Generator	Operating Cost
Diesel Gensets	$0.145/kWh generated
Wind	2%-3.5 % of CAPEX/yr
Batteries	$60,000/yr + $2.50/kWh installed

7.2.4.1 Generation Replacement Costs for 40-year extension

Wind turbines typically have a lifespan of 25 to 30 years, based on current technologies. Therefore, under these assumptions, some capital expenditure will likely be required to extend the life beyond 30 years.

In order to estimate a 40-year lifespan for the wind turbines, a sustaining capital expenditure of 33% of the initial wind turbine CAPEX was included in year 30 of the study period.

Battery energy storage systems a lifespan of 20 years, based on current technologies. After this time, the cells and racks would need to be replaced; however, it is assumed that the container, transformer will last for 40 years. Some fraction of the inverters may need to be replaced as well; however, this would likely be covered in the O&M cost.

In order to estimate a 40-year lifespan, a replacement cost of 50% of the initial storage CAPEX was included for year 20.

7.3 Total Capital and Operating Costs

The total capital cost for each Option is presented Table 7-10 and Figure 7-3. The capital cost varies widely between the Options, with Options 6 and 7 having significantly lower capital costs than the fully interconnected Options. The cost to build transmission and distribution connections is considerably greater than the cost to build generation, as shown in the breakdowns outlined in Figure 7-3.

Additionally, due to the larger size of the communities, and the remoteness, the capital cost for supply to the northern communities is greater than that to supply the southern communities. The breakdown is shown in Table 7-10.

Table 7-10: Total Capital Cost Estimates for each of the Options, broken down by both North and South Loop and by T&D and Generation CAPEX.

Option	North Loop	South Loop	T&D	Generation	Total
Option 1	$1,093 M	$545 M	$1,637 M	$-	**$1,637M**
Option 2	$1,492 M	$545 M	$2,037 M	$-	**$2,037 M**
Option 3	$776 M	$545 M	$1,321 M	$-	**$1,321 M**
Option 4	$911 M	$545 M	$1,321 M	$135 M	**$1,456 M**
Option 5	$676 M	$408 M	$945 M	$139 M	**$1,084 M**
Option 6	$99 M	$88 M	$0 M	$187 M	**$187 M**
Option 7	$331 M	$148 M	$333 M	$146 M	**$479 M**

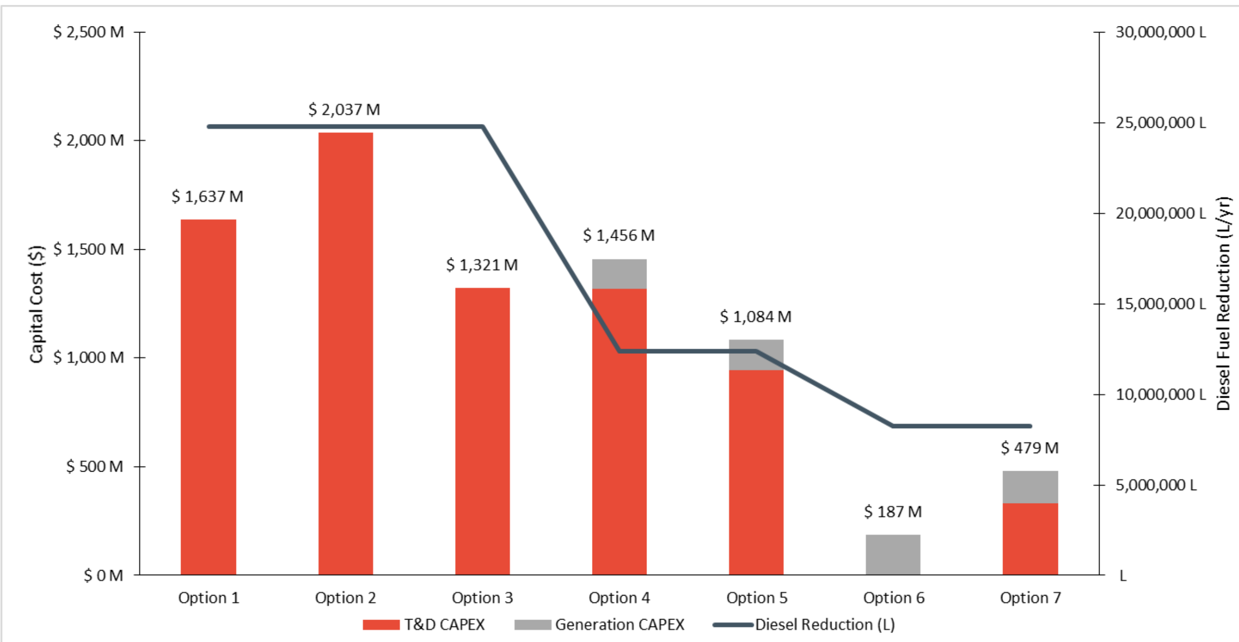


Figure 7-3: Capital Cost Comparison and Diesel Fuel Reduction Estimate for each Option.

The total annual operating cost for each Option is presented 7-4 and Figure 7-4.

The operating cost is dominated by the cost of diesel fuel for Options 4-7, which continue to use diesel for approximately 50% of their energy consumption. Diesel fuel costs are also the most variable component of the annual operating costs, since they are directly tied to world oil pricing.

The operating costs for Options 1-3 are dominated by the system losses and the cost of hydro generation for energy supply. It was assumed that the cost of hydro power for energy supply was approximately $0.05/kWh. The annual operating costs of these interconnected systems remain lower than the isolated systems. These operating costs may potentially be further lowered if the reactive power compensation is optimized to minimize losses (particularly in Option 3).

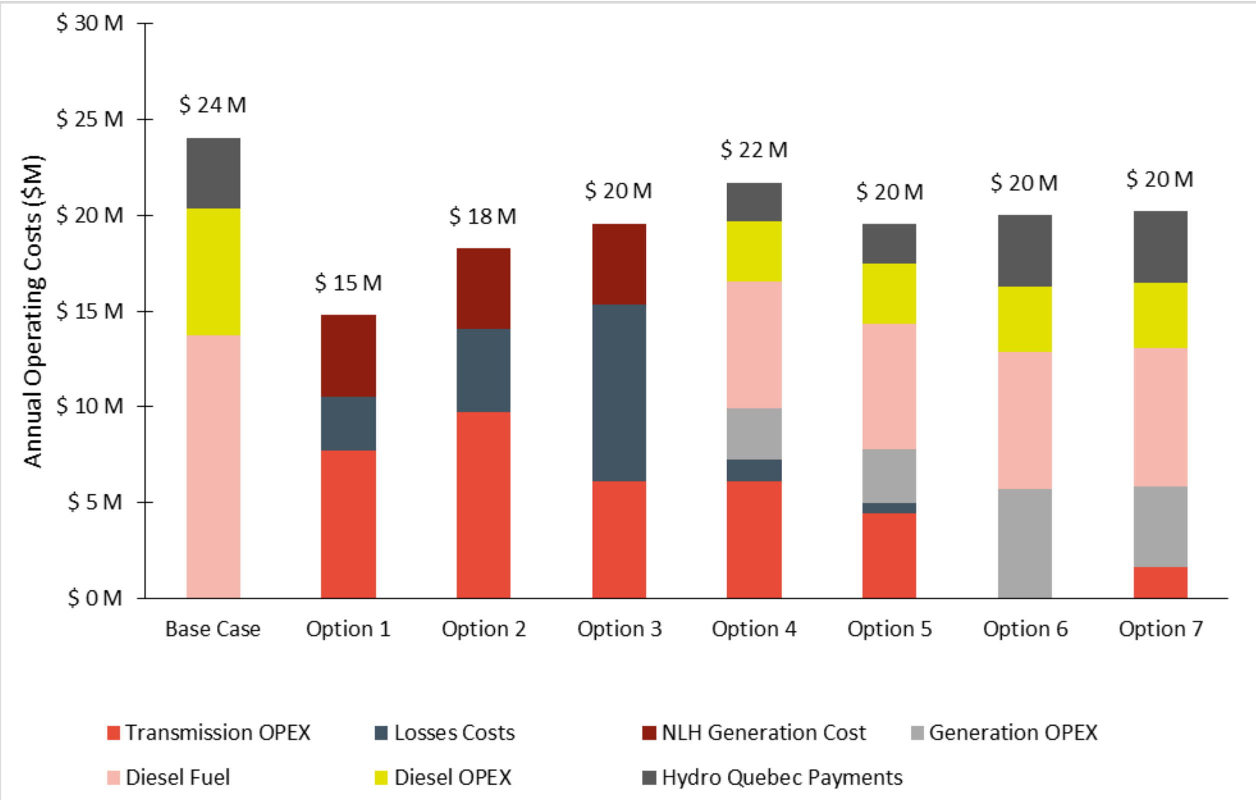


Figure 7-4: Total Operating Costs for Each Option, broken down by components

*additional NLH Generation Costs for marginal energy costs to supply Voisey's Bay would be required for Option 1-3 if the system is fully interconnected and serves the Voisey's Bay mine.

Table 7-11: Total Operating Costs for Each Option, broken down by components

Option	T&D OPEX	Generation OPEX	System Losses	CHF/MF Costs	Fuel Cost	Diesel OPEX	Hydro Quebec Purchase	Total OPEX
Base Case	$0 M	$0 M	$0 M	$0 M	$13.8 M	$6.7 M	$3.7 M	$24.1 M
Option 1	$7.7 M	$0 M	$2.9 M	$4.2 M	$ 0 M	$ 0 M	$ 0 M	$14.8 M
Option 2	$9.7 M	$0 M	$4.4 M	$4.2 M	$ 0 M	$ 0 M	$ 0 M	$18.3 M
Option 3	$6.1 M	$0 M	$9.2 M	$4.2 M	$ 0 M	$ 0 M	$ 0 M	$19.6 M
Option 4	$6.1 M	$2.7 M	$1.1 M	$0 M	$6.6 M	$3.2 M	$2.1 M	$21.7 M
Option 5	$4.5 M	$2.8 M	$0.5 M	$0 M	$6.6 M	$3.2 M	$2.1 M	$19.6 M
Option 6	$0 M	$5.7 M	$0 M	$0 M	$7.2 M	$3.5 M	$3.7 M	$20.0 M
Option 7	$1.6 M	$4.3 M	$0 M	$0 M	$7.2 M	$3.5 M	$3.7 M	$20.2 M

7.3.1 Option 1

The following Table 7-12 and Figure 7-5 illustrate the estimated capital costs for Option 1. The majority of the costs associated with this Option are in the construction of the transmission lines and associated infrastructure (94% of total), with the majority of these costs being in the Northern Loop section of the network. Further details of the capital cost breakdown are provided in Appendix D.

Table 7-12: Capital Cost Summary, Option 1

Infrastructure	Capital Costs ($M)	% of Total
Transmission Lines - Northern Loop	$1,048	64%
Transmission Lines - Southern Loop	$487	30%
Substations - Northern Loop	$45	3%
Substations - Southern Loop	$58	3%
Generation - Northern Loop	0	0%
Generation - Southern Loop	0	0%
Total	**$1,637**	**100%**

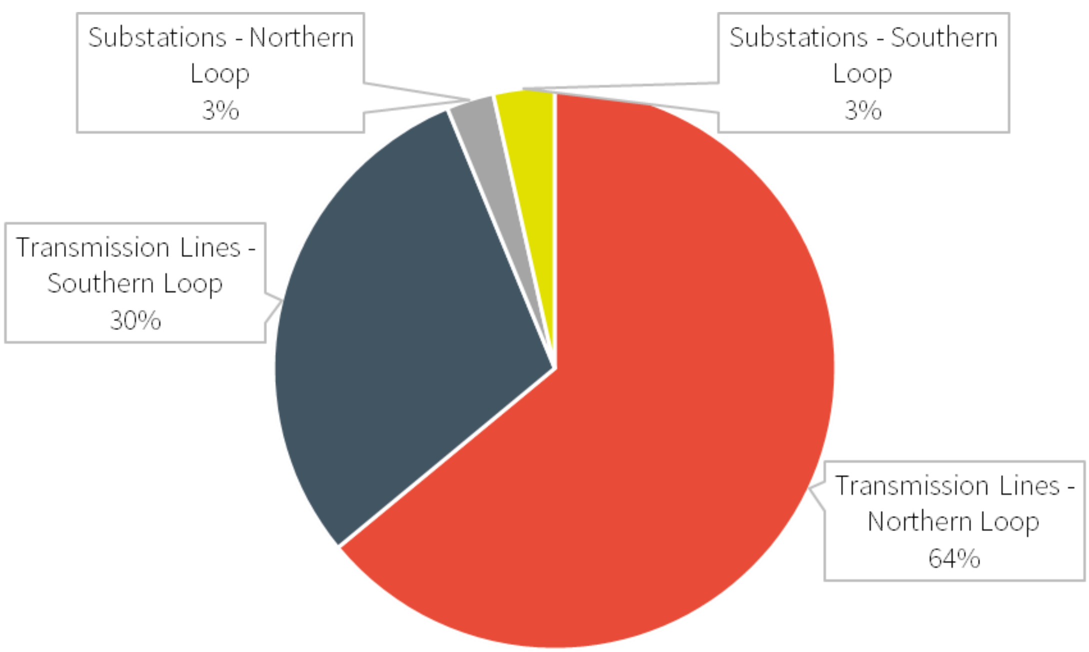


Figure 7-5: Capital Cost Summary, Option 1

7.3.2 *Option 2*

The following Table 7-13 and Figure 7-6 illustrate the estimated capital costs for Option 2. The majority of the costs associated with this Option are in the construction of the transmission lines and associated infrastructure (96% of total), with the majority of these costs being in the Northern Loop section of the network. Further details of the capital cost breakdown are provided in Appendix D.

Table 7-13: Capital Cost Summary, Option 2

Infrastructure	Capital Costs ($M)	% of Total
Transmission Lines - Northern Loop	$1,455	71%
Transmission Lines - Southern Loop	$487	24%
Substations - Northern Loop	$37	2%
Substations - Southern Loop	$58	3%
Generation - Northern Loop	0	0%
Generation - Southern Loop	0	0%
Total	**$2,037**	**100%**

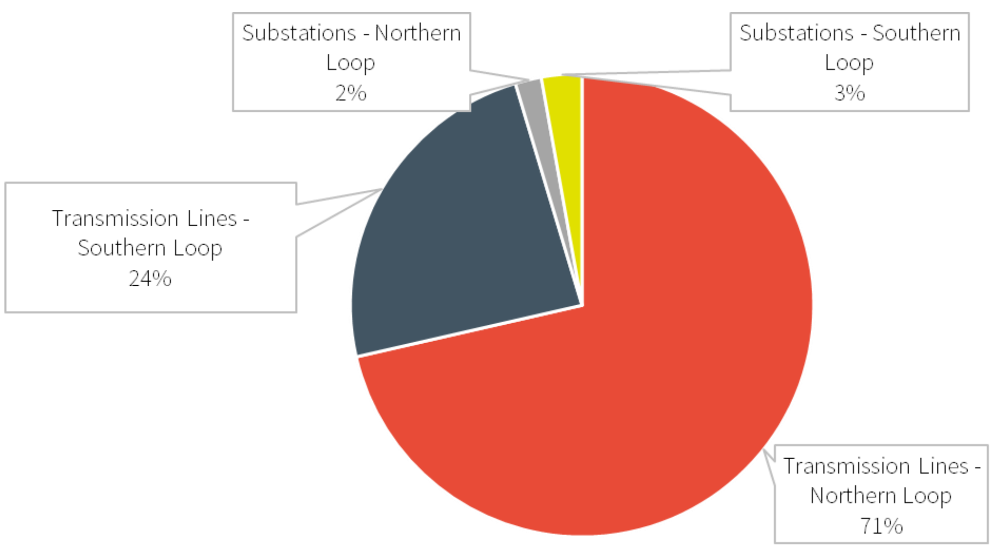


Figure 7-6: Capital Cost Summary, Option 2

7.3.3 *Option 3*

The following Table 7-14 and Figure 7-7 illustrate the estimated capital costs for Option 3. The majority of the costs associated with this Option are in the construction of the transmission lines and associated infrastructure (93% of total), with the majority of these costs being in the Northern Loop section of the network. Further details of the capital cost breakdown are provided in Appendix D.

Table 7-14: Capital Cost Summary, Option 3

Infrastructure	Capital Costs ($M)	% of Total
Transmission Lines - Northern Loop	$739	56%
Transmission Lines - Southern Loop	$487	37%
Substations - Northern Loop	$37	3%
Substations - Southern Loop	$58	4%
Generation - Northern Loop	0	0%
Generation - Southern Loop	0	0%
Total	**$1,321**	**100%**

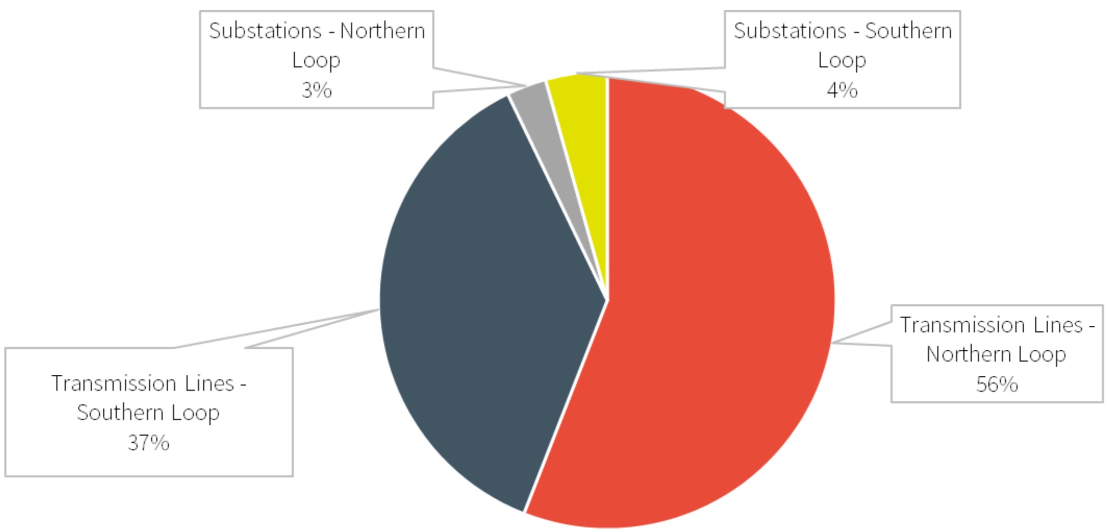


Figure 7-7: Capital Cost Summary, Option 3

7.3.4 Option 4

The following Table 7-15 and Figure 7-8 illustrate the estimated capital costs for Option 4. The majority of the costs associated with this Option are in the construction of the transmission lines and associated infrastructure (84% of total), with the majority of these costs being in the Northern Loop section of the network. Further details of the capital cost breakdown are provided in Appendix D.

Table 7-15: Capital Cost Summary, Option 4

Infrastructure	Capital Costs ($M)	% of Total
Transmission Lines - Northern Loop	$739	51%
Transmission Lines - Southern Loop	$487	33%
Substations - Northern Loop	$37	3%
Substations - Southern Loop	$58	4%
Generation - Northern Loop	$135	9%
Generation - Southern Loop	$-	0%
Total	**$1,456**	**100%**

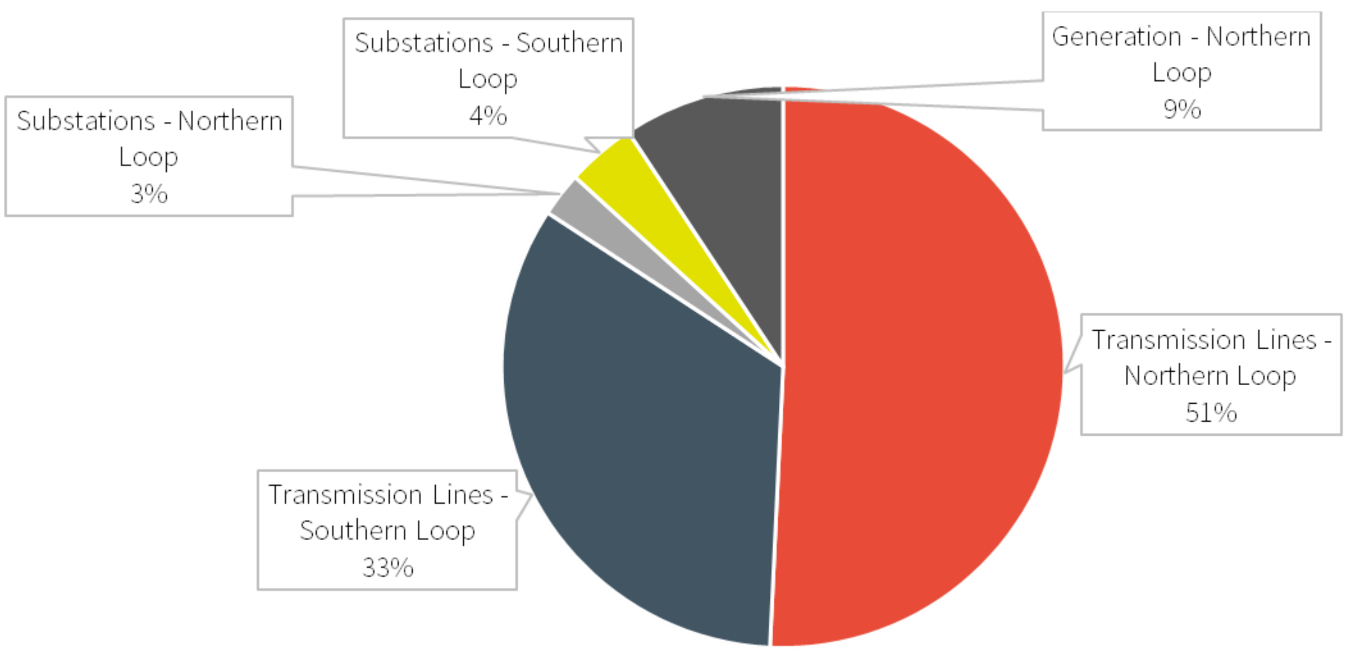


Figure 7-8: Capital Cost Summary, Option 4

7.3.5 Option 5

The following Table 7-16 and Figure 7-5 illustrate the estimated capital costs for Option 5. The majority of the costs associated with this Option are in the construction of the transmission lines and associated infrastructure (79% of total), with the majority of these costs being in the Northern Loop section of the network. Further details of the capital cost breakdown are provided in Appendix D.

Table 7-16: Capital Cost Summary, Option 5

Infrastructure	Capital Costs ($M)	% of Total
Transmission Lines - Northern Loop	$577	53%
Transmission Lines - Southern Loop	$283	26%
Substations - Northern Loop	$37	3%
Substations - Southern Loop	$48	4%
Generation - Northern Loop	$62	6%
Generation - Southern Loop	$77	7%
Total	**$1,084**	**100%**

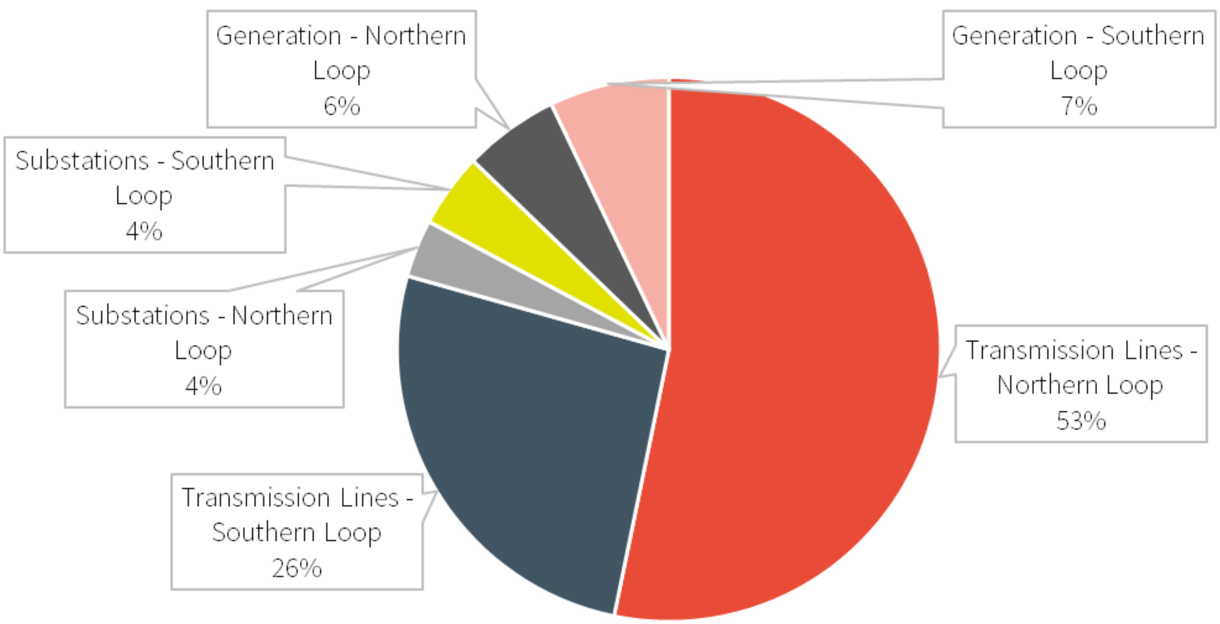


Figure 7-9: Capital Cost Summary, Option 5

7.3.6 *Option 6*

The following Table 7-17 and Figure 7-10 illustrate the estimated capital costs for Option 6. All capital costs associated with this Option are in the construction of the generation assets and associated infrastructure, with the majority of these costs being in the Northern Loop section of the network. Further details of the capital cost breakdown are provided in Appendix D.

Table 7-17: Capital Cost Summary, Option 6

Infrastructure	Capital Costs ($M)	% of Total
Transmission Lines - Northern Loop	$-	0%
Transmission Lines - Southern Loop	$-	0%
Substations - Northern Loop	$-	0%
Substations - Southern Loop	$-	0%
Generation - Northern Loop	$99	53%
Generation - Southern Loop	$88	47%
Total	**$187**	**100%**

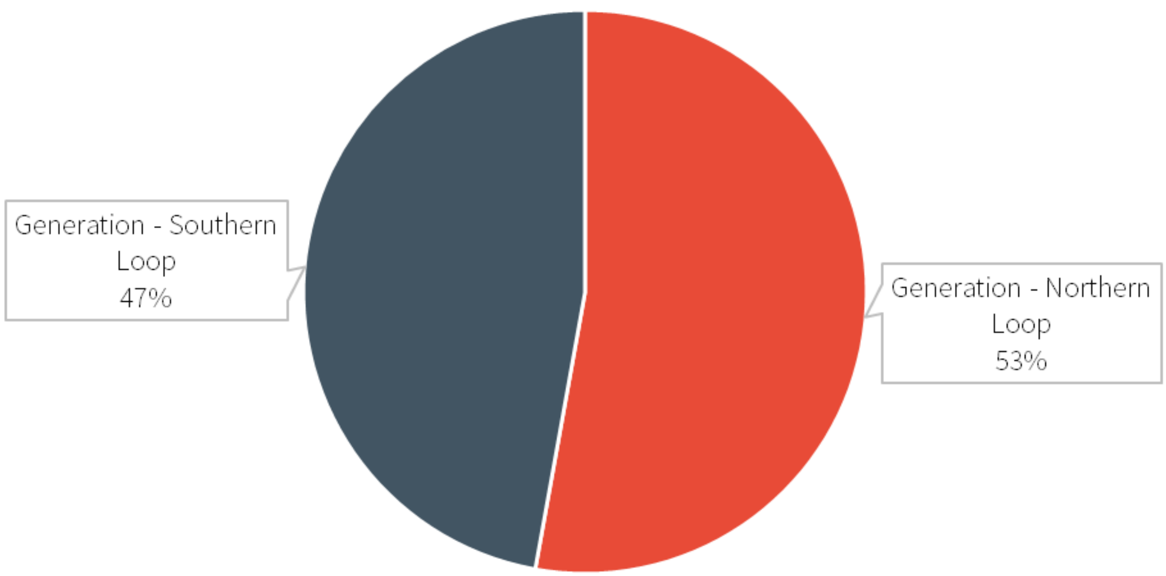


Figure 7-10: Capital Cost Summary, Option 6

A breakdown of the capital cost per community is presented in Table 7-18, along with the total capital and the percentage contribution to the total. The total CAPEX is estimated at $187 M, with $99 M CAPEX for the 6 northern communities and $88 M CAPEX for the 9 southern communities.

Table 7-18: Capital Cost Estimate for Each Community

Community	Wind	Energy Storage	Capital Cost ($M)	% of Total
Nain	1 x 3,500 kW	2,500 kW/1,250 kWh	$21	11%
Natuashish	1 x 3,500 kW	2,500 kW/1,250 kWh	$21	11%
Hopedale	1 x 3,500 kW	1,500 kW/750kWh	$19	10%
Makkovik	3 x 800 kW	800 kW/400 kWh	$18	10%
Postville	800 kW	500 kW/250 kWh	$7	4%
Rigolet	2 x 800 kW	750 kW/375 kWh	$13	7%
Paradise River	1 x 95 kW	100 kW/50 kWh	$4	2%
Cartwright	3 x 800 kW	800kW/400 kWh	$18	10%
Black Tickle	1 x 800 kW	300 kW/150 kWh	$7	4%
Port Hope Simpson	2x 800 kW	800kW/400 kWh	$13	7%
Charlottetown	3 x 800 kW	800kW/400 kWh	$18	10%
Norman Bay	1 x 95 kW	50 kW/25 kWh	$3	2%
St. Lewis	1 x 800 kW	400 kW/200 kWh	$8	4%
Mary's Harbour	3 x 800 kW	800kW/400 kWh	$18	10%
L'Anse-au-Loop	0 kW	0 kW/0 kWh	$0	0%
Total North	**3 x 3.5 MW, 6 x 800 kW**	**8,550 kW/4,275 kWh**	**$99**	**53%**
Total South	**13 x 800 kW, 2 x 95 kW**	**4,050 kW/2,025 kWh**	**$88**	**47%**
Total	**3 x 3.5 MW, 19 x 800 kW, 2 x 95 kW**	**12,600 kW/ 6,300 kWh**	**$187**	**100%**

Adding wind to L'Anse-au-Loop was not included since this community is already served by low cost Hydro power from Hydro Quebec. If wind was considered for L'Anse-au-Loop, the generation requirements are 14 MW of wind, which leads to an estimated CAPEX of approximately $58 M, adding approximately 30% additional CAPEX for this Option. Since L'Anse-au-Loop already has a connection to hydroelectric generation from Hydro Quebec, it will likely be more economical to continue to purchase generation from Hydro Quebec.

7.3.7 Option 7

The following Table 7-19 and Figure 7-11 illustrate the estimated capital costs for Option 7. The majority of capital costs associated with this Option are in the construction of the transmission assets and generation assets (55% and 33% respectively), with the majority of these costs being in the Northern Loop section of the network. Further details of the capital cost breakdown are provided in Appendix D.

Table 7-19: Capital Cost Summary, Option 7

Infrastructure	Capital Costs ($M)	% of Total
Transmission Lines - Northern Loop	$219	46%
Transmission Lines - Southern Loop	$55	12%
Substations - Northern Loop	$27	6%
Substations - Southern Loop	$31	7%
Generation - Northern Loop	$85	18%
Generation - Southern Loop	$61	13%
Total	**$479**	**100%**

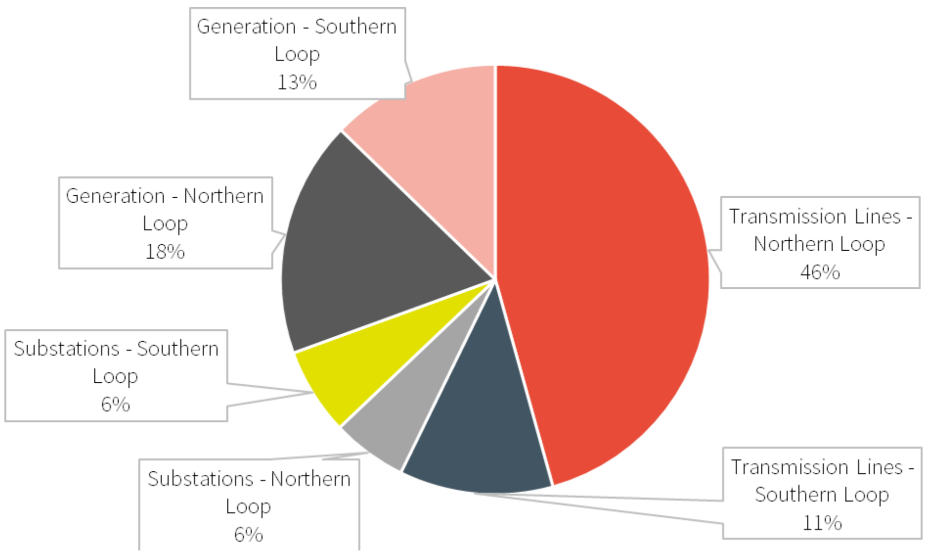


Figure 7-11: Capital Cost Summary, Option 7

A breakdown of the capital cost per microgrid is presented in Table 7-20, along with the total capital and the percentage contribution to the total. The total CAPEX is estimated at $479 M, with $331 M CAPEX for the 6 northern communities and $148 M CAPEX for the 9 southern communities.

The Nain – Natuashish and Hopedale, Postville and Makkovik microgrids are the greatest contributors to the total CAPEX for this Option. This is expected since these are relatively large communities (except Postville) that are the most remote in Labrador. Therefore, the high costs are associated with added reliability and redundancy for the transmission system.

The Port Hope Simpson microgrid serving 5 communities is also a significant capital cost; however, lower than both the other two microgrids. These communities generally have lower loads than the Northern communities and the system is configured as 3 radial feeders from Port Hope Simpson, thus allowing for lower voltage distribution lines. Additionally, since these communities are more accessible the substations do not include a second transformer, which lowers the total capital cost.

Table 7-20: Capital Cost Estimate for Each Community

Community	Transmission	Wind Generation	Energy Storage	Capital Cost ($M)	Percentage of Total
Nain, Natuashish	145 km x 69 kV, + 2 substations	2 x 3,500 kW	3,500 kW/1,750 kWh	$133	29%
Hopedale, Postville Makkovik	232 km x 69 kV + 3 substations	2 x 3,500 kW	3,500 kW/1,750 kW	$185	38%
Rigolet	N/A	2 x 800 kW	750 kW/375 kWh	$13	3%
Cartwright & Paradise River	47 km x 69 kV, 2 substations	3 x 800 kW	800 kW/400 kWh	$39	8%
Black Tickle	N/A	1 x 800 kW	300 kW/150 kWh	$7	1%
Port Hope Simpson, Charlottetown, Norman Bay, St. Lewis, Mary's Harbour	220 km x 25 kV, 5 substations	2 x 3,500 kW	3,500 kW/1,750 kW	$96	20%
L'Anse-au-Loop	N/A	0	0	$-	0%
Mobile Substation	For backup for southern communities			$6	1%
Total North	**377 km x 69 kV + 5 substations**	**4 x 3.5 MW, 2 x 800 kW**	**7,750 kW/ 3,875 kWh**	**$331**	**70%**
Total South	**47 km x 69 kV + 220 km x 25 kV + 7 substations**	**2 x 3.5 MW, 1 x 800 kW**	**4,600 kW/ 2,300 kWh**	**$148**	**30%**
Total	**424 km x 69 kV + 220 km x 25 kV + 12 substations**	**7 x 3.5 MW, 3 x 800 kW**	**12,350 kW/ 6,175 kWh**	**$479**	**100%**

As with Option 6, adding wind to L'Anse-au-Loop was not considered. Connecting this community is also not likely to be economic due to the long 149 km transmission line. If wind was considered for L'Anse-au-Loop, the generation requirements are 14 MW of wind, which leads to an estimated CAPEX of approximately $58 M.

8. Diesel Plant Decommissioning Assessment

It is envisioned that the scope of decommissioning of the diesel plants may be tailored to the particular needs of the site. In some cases, it is considered that the diesel plants will be maintained in operation as backup power assets to provide increased reliability. In the cases where the existing diesel plants are not intended to continue operation, various decommissioning activities may be carried out to ensure the safe and secure transition of the site from operation to either repurposing for other use or divestment of the site. In particular, high-level cost estimates have been prepared under two different decommissioning scenarios:

Basic Decommissioning:

- Disconnection of equipment;
- Removal of fuel and hazardous materials;
- Disconnection of site utilities including capping of water/wastewater connections;
- Cleaning and closing of fuel tanks; and
- Closing and securing the site.

Full Decommissioning, including basic decommissioning activities plus:

- Removal of thermal equipment, fuel tanks;
- Removal of electrical equipment including transformers, switches, protection and controls equipment;
- Demolition of buildings, structures and foundations; and
- Re-grading of site.

For the purposes of this study, full site remediation has not been included as these costs are expected to vary significantly depending on the site condition. In the case of basic decommissioning it is expected that remaining fuel on-site will be used or repurposed, and that all equipment will be stored on-site.

In many cases the existing equipment may have resale or salvage value; however, depending on the location, removal and transportation costs may be significant relative to any salvage value, hence residual value of equipment has not been explicitly addressed. It is expected that the cost to relocate equipment would be offset by the residual value of the equipment if it is sold or repurposed for use at another site.

Given the remote nature of the sites, and the varying age of the existing diesel generation sites, it is expected that the optimal outcome for many of these sites will not be decommissioning. Based on reliability requirements, the sites may be kept operational as backup power facilities, as the communities may be vulnerable to power outages caused by a failure on the transmission line.

Additionally, given the remote locations of these communities, it is very costly to build infrastructure in the region. It may be worthwhile to investigate opportunities to repurpose the infrastructure in the communities (building, storage tanks, etc.). This may be more cost effective than removing the infrastructure and re-constructing new infrastructure at a later time. The ability to repurpose the infrastructure from the diesel plants would need to be evaluated on a case-by-case basis based on the current state-of-repair and the needs of each community.

Basic Decommissioning of a typical generator site is expected to include the following activities:

1. Inventory and documentation of equipment on site including:
    - Generators;
    - Electrical devices including switches and relays;
    - Communications equipment;
    - Transformers;
    - Fuel Storage and Tanks;
    - Conduit and Electrical Wiring; and
    - Balance of Plant including ancillary buildings and infrastructure.
2. Inspection of Current Electrical System:
    - Inspect Electrical incoming/outgoing wiring;
    - Review Single Phase and Three-Phase layout throughout the facility; and
    - Review all breaker panels, identify equipment to be disconnected during de-install.
3. Additional Planning for Disconnecting & Removal:
    - Inventory chemicals and waste fuel and plan for proper disposal; and

- Identify additional site requirements for decommissioning (including site access, security, additional site utilities including water/septic systems). Note the cost of decommissioning other site utilities, securing the site and any site remediation has not been included in our cost estimate.

4. Execution of Basic Decommissioning:
   - Project management and scheduling of resources;
   - Provision of temporary power for decommissioning activities;
   - Disconnect power from main breaker for all equipment involved;
   - Decoupling of other utilities including auxiliary power, telephone, IT networks, communication services, potable water, service water, fire water, sewer, instrument air, service air, digital control systems, fire and security alarm systems, and batteries;
   - Remove all chemicals and waste fuel and dispose of properly; and
   - Close and secure the site.
5. Execution of Full Decommissioning
   - Packing and removal of equipment, stored materials and tools;
   - Demolition and removal of storage tanks;
   - Demolition and removal of structures including buildings, poles, and fences;
   - Demolition and excavation of foundations, concrete pads & vaults; and
   - Site backfilling and regrading.
6. Closeout
   - Revision to as-built drawings;
   - Update of inventory records;
   - Completion of all project documentation; and
   - Transfer of site management / ownership as applicable.

In general, costs for decommissioning thermal generation facilities will vary widely. Published costs are not generally available for smaller facilities. Decommissioning costs for larger fossil-based generation plants have been published in the range of $10-50 /kW.[8] Based on Hatch's subject matter experts' opinion and the remote locations of the communities, an average cost of $30-40/kW for basic decommissioning, and an average cost of $60-100/kW for full decommissioning has been assumed.

However, if additional environmental remediation is required for the sites, the costs could be much higher, depending on the level of fuel contamination in the surrounding soils. This would need to be evaluated for each site by testing the soil.

8.1 Cost Estimate per Community

Based on the assumptions outlined above, the diesel plant decommissioning costs have been outlined below for the basic decommissioning option and the full decommissioning. As noted above, these costs do not include estimates for site remediation or contamination removal.

The costs were assumed to be $30/kW for the basic decommissioning for the southern communities and $40/kW for the northern communities and Black Tickle, since it is inaccessible by road.

For the full decommissioning, the costs were assumed to be $60/kW for the southern communities and $100/kW for the northern communities and Black Tickle.

The cost per community and the total cost is presented in Table 8-1. The total estimated costs are $2.6 M for the full decommissioning and $1.2 M for the basic decommissioning. These costs are relatively small in comparison to the total project capital costs, ranging from $1.3 – $2.0 B.

However, if NL Hydro elects to proceed with the full decommissioning, there may be added costs if there have been any spills or soil contamination. Depending on the remoteness of the site and the scale of contamination, these costs could be significantly higher than the costs to decommission and remove the equipment.

[8] Dismantling cost study for generating stations, Prepared for Xcel Energy by TLG Services Inc., 2011. Available at: http://www.debarel.com/BSB_Library/8_Seymore_Exhibit_1.pdf

Table 8-1: Estimated Decommissioning Costs for Diesel Power Plants

Community	Loop	Diesel Plant Capacity (kW)	Full Decommissioning	Basic Decommissioning
Nain	Northern	3,755	$375,500	$150,200
Natuashish	Northern	3,337	$333,700	$133,480
Hopedale	Northern	2,629	$262,900	$105,160
Makkovik	Northern	1,765	$176,500	$70,600
Postville	Northern	1,067	$106,700	$42,680
Rigolet	Northern	1,320	$132,000	$52,800
Cartwright	Southern	2,220	$133,200	$66,600
Paradise River	Southern	148	$8,880	$4,440
Black Tickle	Southern	1,005	$100,500	$40,200
Norman Bay	Southern	160	$9,600	$4,800
Charlottetown	Southern	1,635	$98,100	$49,050
Port Hope Simpson	Southern	1,725	$103,500	$51,750
Mary's Harbour	Southern	2,615	$156,900	$78,450
Saint Lewis	Southern	1,020	$61,200	$30,600
L'Anse-au-Loop	Southern	8,050	$483,000	$241,500
Total			**$ 2,600,000**	**$ 1,200,000**

*Note these costs have not been included in the total project CAPEX estimates.

8.2 Consideration for Reliability

As NL Hydro continues to explore the different Options to reduce diesel fuel usage for the isolated communities, reliability will inherently be part of the discussion. The major reliability considerations are outlined in Section 6 for each Option.

For the fully interconnected Options, Option 1, 2, and 3, there are different levels of reliability within each configuration.

Option 1 and 2 have loop designs in the North and a radial design in the south, while Option 3 has two radial designs. However, the CAPEX of Option 3 is $300 - $700M lower than Option 1 and 2.

If a fully interconnected Option is desired, keeping the diesel gensets in standby as backup may be prudent, particularly for the remote northern communities. This option may be particularly interesting for Option 3, where the gensets could increase the design’s reliability without major added capital cost.

Furthermore, for all Options with decommissioning, the cost of decommissioning should be weighed against the cost of maintaining the gensets in operational condition as backup.

9. Distribution System Upgrades within the Communities

As part of these projects, and due to community load growth, NL Hydro has indicated that they may explore the option of voltage conversion i.e., to upgrade the distribution feeders within the communities to 25 kV from 4.16 kV or 12.5 kV.

The reason for upgrading the primary voltage has many technical and economic benefits. As the communities grow and the load increases, the 4.16 kV lines will become overloaded, thus will eventually require upgrading. Additionally, 25 kV is becoming more common for distribution systems, with many municipalities moving to a 25-kV distribution system. Lastly, generally having a higher distribution voltage and more robust poles will lead to lower loses, increased economic load reach and reduced outages within the community distribution system.

NL Hydro is looking at the option to upgrade these distribution networks in parallel (or prior) to the interconnection Options outlined in this study. If one of the fully interconnected Options or the optimized microgrid Option (Option 1-5 or 7) is selected, this will involve constructing a substation in each community. If the community needs a voltage upgrade on the distribution lines, it is prudent to do this upgrade with or before integration of the community, to select the approve secondary voltage on the transformers (or eliminate the need for a transformer) serving each community.

A summary of the distribution voltage, the length of distribution lines in each community and comments regarding the need to upgrade are presented in Table 9-1.

Table 9-1: Summary of Distribution System in Each Community

Community	Current Distribution Voltage	Length of Lines (km)				Comments
		1 phase	2 phases	3 phases	Total	
Nain	4.16 kV	4.97 km	0 km	6.79 km	11.76 km	To be upgraded
Natuashish	25 kV	Not Available				No upgrade required
Hopedale	4.16 kV	3.89 km	0.15 km	2.48 km	6.52 km	To be upgraded
Makkovik	4.16 kV	2.13 km	0.19 km	2.92 km	5.24 km	To be upgraded
Postville	4.16 kV	3.95 km	0 km	1.74 km	5.69 km	To be upgraded
Rigolet	4.16 kV	13.84 km	0 km	1.74 km	15.58 km	To be upgraded
Paradise River	4.16 kV	3.17 km	0.89 km	0.04 km	4.10 km	To be upgraded
Cartwright	4.16 kV	11.15 km	0 km	4.56 km	15.71 km	To be upgraded
Black Tickle	4.16 kV	1.82 km	0 km	4.55 km	6.37 km	To be upgraded
Norman Bay	4.16 kV	1.00 km	0 km	0.58 km	1.58 km	To be upgraded
Charlottetown	4.16 kV	23.52 km	0 km	7.54 km	31.06 km	To be upgraded
Port Hope Simpson	12.5 kV	9.35 km	0 km	2.15 km	11.50 km	May be upgraded, economic decision
Mary's Harbour	4.16 kV	12.79 km	0 km	4.07 km	16.86 km	To be upgraded
Saint Lewis	12.5 kV	5.05 km	0 km	2.81 km	7.86 km	May be upgraded, economic decision
L'Anse-au-Loop	25 kV	60.02 km	4.97 km	49.38 km	114.37 km	No upgrade required
Total					**108.77 km**	

9.1 Community Distribution System Upgrade Costs

Based on Hatch's previous experience regarding the upgrade of distribution systems in urban Ontario settings, the typical cost to build a 25-kV distribution line in a community is between \$8,000 - \$10,000 per pole. This includes provision for the new poles, insulators, new overhead cabling, pole mounted transformers to step down to residential and commercial supply voltage, and decommissioning of the old line.

The proposed solution would be to build the new 25 kV line adjacent to the existing 4.16 kV line. Once the new 25 kV line is energized, the 4.16 kV line can be decommissioned.

Given the remoteness of the sites, increasing the cost to bring materials to site and the labour costs, it is likely the cost will be approximately 30-50% greater per pole, which translates to $13,000- $15,000 per pole.

Typical pole spacing is approximately every 30 m, which is approximately 34 poles per km. The estimated capital cost per km is $450,000 – $500,000/km.

For the southern, more accessible communities, $450,000/km will be used and for the northern, less accessible communities, $500,000/km will be used.

Several of the communities would still need full substations since they would need to have the voltage step down from either 138 kV or 69 kV to 25 kV. There would be some minor savings from having a higher secondary voltage on the transformer; however, they are well within the uncertainty of this estimate.

Five communities would no longer need a step-down substation and would only require a switching station. This would result in savings on the transformers of between $650,000 to $1,000,000 per transformer. However, all the other infrastructure within the substation (line terminations, P&C, breakers, civil works, security measures, etc.) would likely still be required in order to be able to isolate the community from the grid if needed.

9.2 Estimated Capital Cost and Savings

The estimated capital cost to upgrade each community is outlined in Table 9-2. The cost varies considerably based on the length and complexity of the distribution system in each community. The most expensive communities to upgrade are Charlottetown, Rigolet, Mary's Harbour and Cartwright.

The estimated total capital cost to upgrade the distribution in all communities except L'Anse-au-Loop and Natuashish (both of which already have 25 kV distribution) is approximately $65 M. This would add 4-6% to the CAPEX of Option 1-5. For the interconnected communities in Option 7 (all communities excluding Rigolet, Black Tickle, and L'Anse-au-Loop), if the distribution voltage was upgraded it would cost approximately $55 M adding approximately 11% to the total project CAPEX.

Table 9-2: Estimated Costs to Upgrade the Distribution in Each Community

Community	Current Distribution Voltage	Length of Lines	Cost to upgrade
Nain	4.16 kV	11.76 km	$5,880,000
Natuashish	25 kV		N/A
Hopedale	4.16 kV	6.52 km	$3,260,000
Makkovik	4.16 kV	5.24 km	$2,620,000
Postville	4.16 kV	5.69 km	$2,845,000
Rigolet	4.16 kV	15.58 km	$7,790,000
Paradise River	4.16 kV	4.1 km	$1,845,000
Cartwright	4.16 kV	15.714 km	$7,071,300
Black Tickle	4.16 kV	6.37 km	$2,866,500
Norman Bay	4.16 kV	1.58 km	$711,000
Charlottetown	4.16 kV	31.06 km	$13,977,000
Port Hope Simpson	12.5 kV	11.50 km	$5,175,000
Mary's Harbour	4.16 kV	16.86 km	$7,587,000
Saint Lewis	12.5 kV	7.86 km	$3,537,000
L'Anse-au-Loop	25 kV	114.37 km	N/A
Total		**139.83 km**	**$65,165,000**

*Note these costs have not been included in the total project CAPEX estimates.

Port Hope Simpson and Saint Lewis currently operate on 12.5 kV. There is currently no technical need to upgrade these communities; however, upgrading may be beneficial for easing maintenance complexity, reducing spare parts inventory, and to eliminate the stepdown to 12.5 kV in the communities. The cost of upgrading Port Hope Simpson and Saint Lewis is estimated at $8.7 M.

Unfortunately, the estimated savings on the transformers serving the communities is relatively minor; the estimates are outlined in Table 9-3. Since many of the communities continue to require voltage step down, the savings are not considerable. Only Nain, Black Tickle (after the subsea cable), Norman Bay, Charlottetown and Saint Lewis can avoid a step-down transformer. This leads to an estimated savings of $4-6 M.

Table 9-3: Estimated Savings on Transformers due to Voltage Upgrade

Community	Cost to upgrade	Savings on Transformers
Nain	$5,880,000	$1,300,000 - $2,000,000 Planned for 2 transformers in Nain for redundancy
Natuashish	N/A	
Hopedale	$3,260,000	Minor (still need 138 kV to 25 kV TFMR x 2)
Makkovik	$2,620,000	Minor (still need 138 kV to 25 kV TFMR x 2)
Postville	$2,845,000	Minor (still need 138 kV to 25 kV TFMR x 2)
Rigolet	$7,790,000	Minor (still need 138 kV to 25 kV TFMR x 2)
Paradise River	$1,845,000	Minor (still need 69 kV to 25 kV TFMR)
Cartwright	$7,071,300	Minor (still need 69 kV to 25 kV TFMR)
Black Tickle	$2,866,500	$650,000 - $1,000,000
Norman Bay	$711,000	$650,000 - $1,000,000
Charlottetown	$13,977,000	$650,000 - $1,000,000
Port Hope Simpson	$5,175,000	Minor (still need 69 kV to 25 kV TFMR x 2)
Mary's Harbour	$7,587,000	Minor (still need 69 kV to 25 kV TFMR)
Saint Lewis	$3,537,000	$650,000 - $1,000,000
L'Anse-au-Loop	N/A	
Total	**$65,165,000**	**$3,900,000 - $6,000,000**

The cost to upgrade the distribution system upgrade in each community is a relatively small component of the overall interconnection project cost. If NL Hydro elects to complete a full interconnected grid, it would be prudent to upgrade the distribution in the communities currently approaching overloaded states. This would avoid added costs in the future to upgrade the substation serving the communities (and avoid stranded assets when a transformer is no longer needed when the distribution is upgraded).

10. Total Lifecycle Cost Assessment

The total cost of ownership for each of the Options, along with a base case (which just includes diesel fuel and engine maintenance) was calculated in order to compare the Options on a lifecycle basis. The total cost of ownership was calculated for a 20-year period, using a real discount rate of 5.65%. Fuel costs were based on 2020 values for each community and escalated with the real discount rate.

The total cost of ownership is presented in Table 10-1 and Figure 10-1 for the different Options.

Table 10-1: Total Operating Costs for Each Option, broken down by components

Option	Total CAPEX (2020$)	Total OPEX (2020$/yr)	Total Cost of Ownership over 20 years (NPC 2020$)	Diesel Fuel Savings (M L/yr)	GHG Reduction (Metric Tonnes CO2e/yr)
Base Case	$0 M	$24.1 M	$284 M	N/A	N/A
Option 1*	$1,637 M	$14.8 M	$1,812 M	17.5 M L/yr	47 t CO2e /yr
Option 2*	$2,037 M	$18.3 M	$2,252 M	17.5 M L/yr	47 t CO2e /yr
Option 3*	$1,321 M	$19.6 M	$1,552 M	17.5 M L/yr	47 t CO2e /yr
Option 4	$1,456 M	$21.7 M	$1,712 M	9.1 M L/yr	24 t CO2e /yr
Option 5	$1,084 M	$19.6 M	$1,315 M	9.1 M L/yr	24 t CO2e /yr
Option 6	$187 M	$20.0 M	$423 M	8.3 M L/yr	22 t CO2e /yr
Option 7	$479 M	$20.2 M	$717 M	8.3 M L/yr	22 t CO2e /yr

* Fuel reduction and GHG savings not considered from electricity is sold to Vale for Voisey's Bay. The cost of hydropower has not been included in these costs.
**This cost of ownership does not include replacement costs for a battery in Options 5-7.

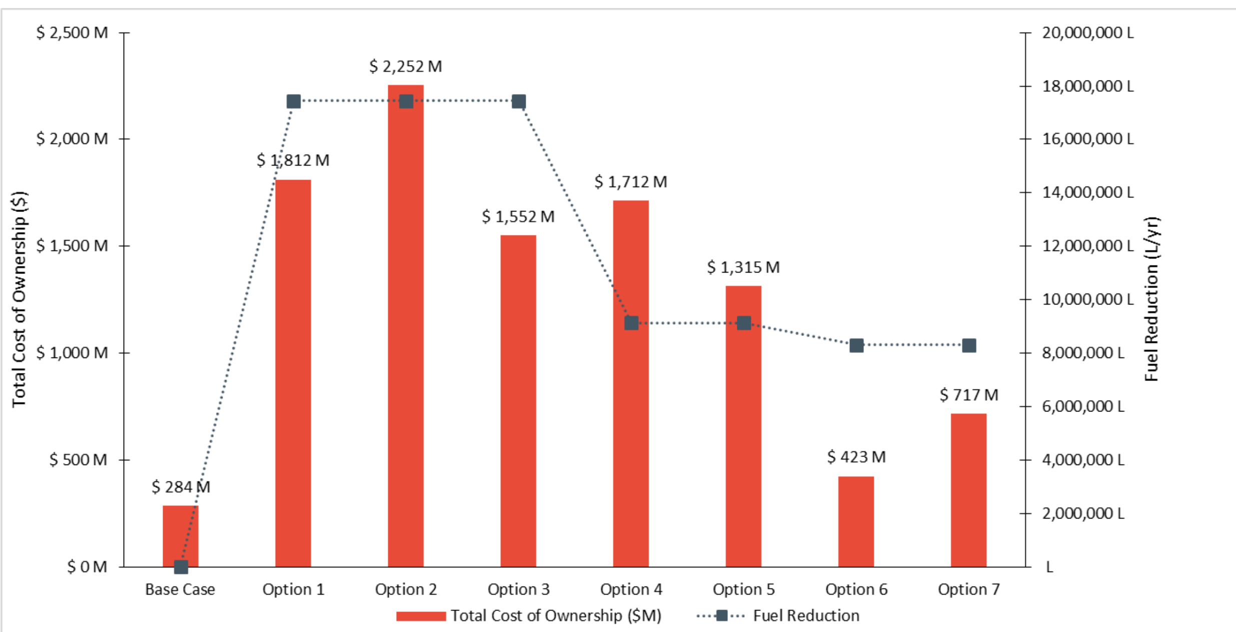


Figure 10-1: Comparison of Total Cost of Ownership to Annual Fuel Reduction for 20-year study period.

Options 1 - 2 have high costs of ownership; however, for these Options, NL Hydro has greater revenue potential if electricity can be sold to Vale for Voisey's Bay to reduce their diesel usage. Option 2 has the highest cost of ownership of all Options.

Option 3 has a cost of ownership similar to Option 5. It is likely that for Option 3, the diesel gensets will need to be maintained as backup in the communities to maintain reliability. This will increase the total cost of ownership for Option 3.

Option 4 has the third highest cost of ownership and has a lower fuel savings compared to Options 1-3. Option 4 has costs associated to both the installation and operation of wind generation and of a long radial transmission network. Additionally, the diesel gensets within the communities continue to operate to serve approximately 50% of the demand.

Option 5 has the third lowest total cost of ownership. This Option reduces the major transmission related capital costs and operating costs associated with connecting to Muskrat and Churchill Falls. Option 5 continues to have approximately 50% of the generation supplied by imported diesel fuel.

Options 6 and 7 have the overall lowest total costs of ownership, which is consistent with their considerably lower capital costs compared to the more interconnected Options. However, these Options also have the lowest GHG reductions and continue to operate with approximately 50% of the electricity supplied by imported diesel fuel. Option 7 has a higher total cost of ownership; however, it has added reliability by connecting 2-5 communities.

However, with Option 1-3, there is the potential to supply all of the electricity to Voisey's Bay Mine as well. This would add some marginal energy costs (Churchill and Muskrat Falls short run energy cost); however, would not significantly change the total cost of ownership. It is estimated that Voisey's Bay consumes approximately 284 GWh of electricity per year, which is over 3 times greater than the communities.

For Option 4-5, there is also the potential to sell excess wind generation in the North to Voisey's Bay. This generation would otherwise have been curtailed. Therefore, this option adds potential revenue without increasing the operating costs for NL Hydro. In Option 4, this represents approximately 69 GWh per year and in Option 5, this represents approximately 32 GWh per year.

The added cost of selling electricity to Voisey's Bay is shown in Figure 10-2, showing a relatively marginal increase of Option 1-3.

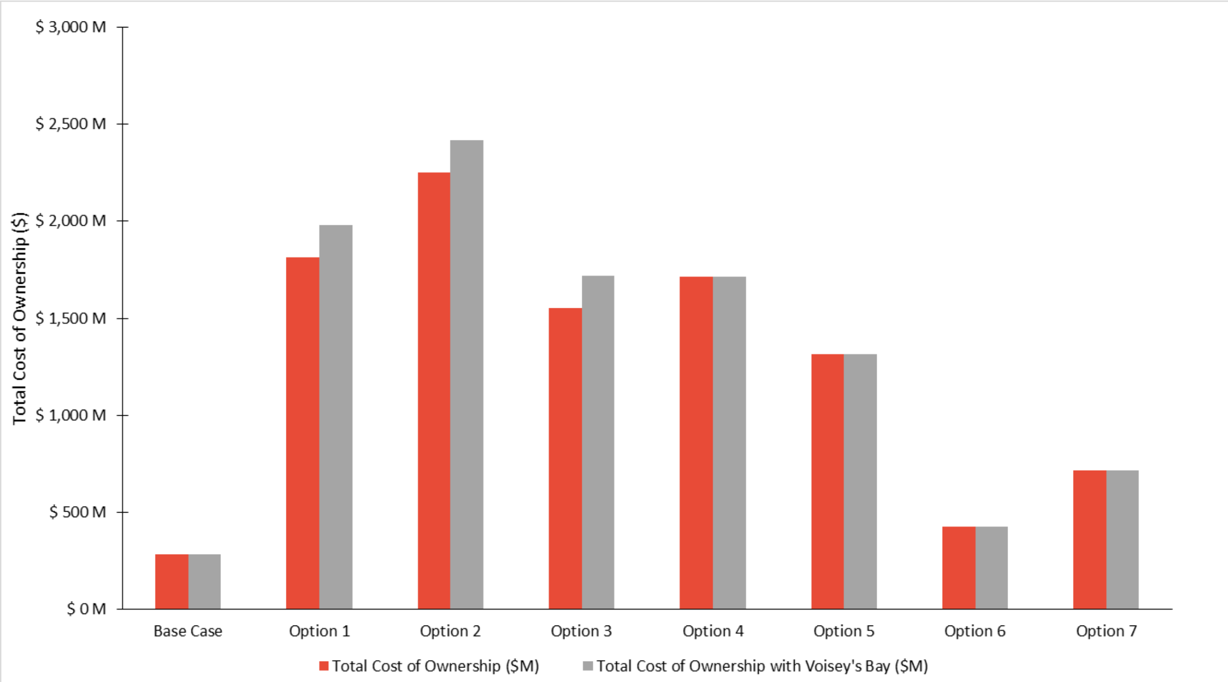


Figure 10-2: Comparison of Total Cost of Ownership with and without sale of electricity to Voisey's Bay (serving Voisey's Bay for 20 years)

10.1 Levelized Cost of Energy

The levelized cost of energy (LCOE) is a representation of the cost to generate electricity. An average LCOE was calculated for each of the Options.

The LCOE is calculated by taking the total cost of ownership over the study period (20 years) and dividing it by the forecasted amount of electricity sales over the study period. Future electricity sales are discounted at the same real discount rate as used for the financial calculations (5.65%).

Four scenarios were reviewed for the LCOE study. The first scenario investigated NL Hydro serving only the communities. The second scenario investigated NL Hydro serving Voisey's Bay for the entire 20-year period. Based on preliminary discussions with Vale, they have indicated that Voisey's Bay may continue to operate to a maximum of 30 additional years (from 2020); however, the official mine closure is planned for the mid-2030s. Therefore, in order to comfortably sell electricity to Voisey's Bay for 20 years, the transmission lines and substations must be installed in the late 2020s.

The third and fourth scenario investigated NL Hydro serving Voisey's Bay for a 15 year and 10 year mine life, respectively. For Option 1-3 100% of Voisey's Bay load with hydro and

100% of the curtailed wind energy in Option 4-5 is sold to Voisey's Bay. The Base Case and Option 6-7 do not involve a connection to Voisey's Bay, so the LCOE estimates do not change between the scenarios.

The estimated LCOE is presented in Figure 10-3 and Table 10-2. As shown for Option 1-3, the LCOE will shift significantly based on the amount of electricity that can be sold to Voisey's Bay. Option 3 becomes lower than or comparable to Option 6 if the mine life is between 15-20 years. As well, Option 1 is also comparable, at \$0.04 - \$0.09/kWh higher than Option 6 if the mine life is between 15-20 years.

However, there is more uncertainty when considering selling electricity to Voisey's Bay. If the interconnected Options were selected, they would need to be installed and operating within the next 5-7 years in order to potentially achieve a 20-year sale period to Voisey's Bay.

It may also be possible that this transmission line could drive economic growth by bringing low cost reliable electricity to Northern Labrador, leading to the development of new industrial facilities. However, at this time, the opportunities are unknown and would need to be thoroughly investigated and vetted in order to influence the decision, given the high CAPEX for Option 1-3.

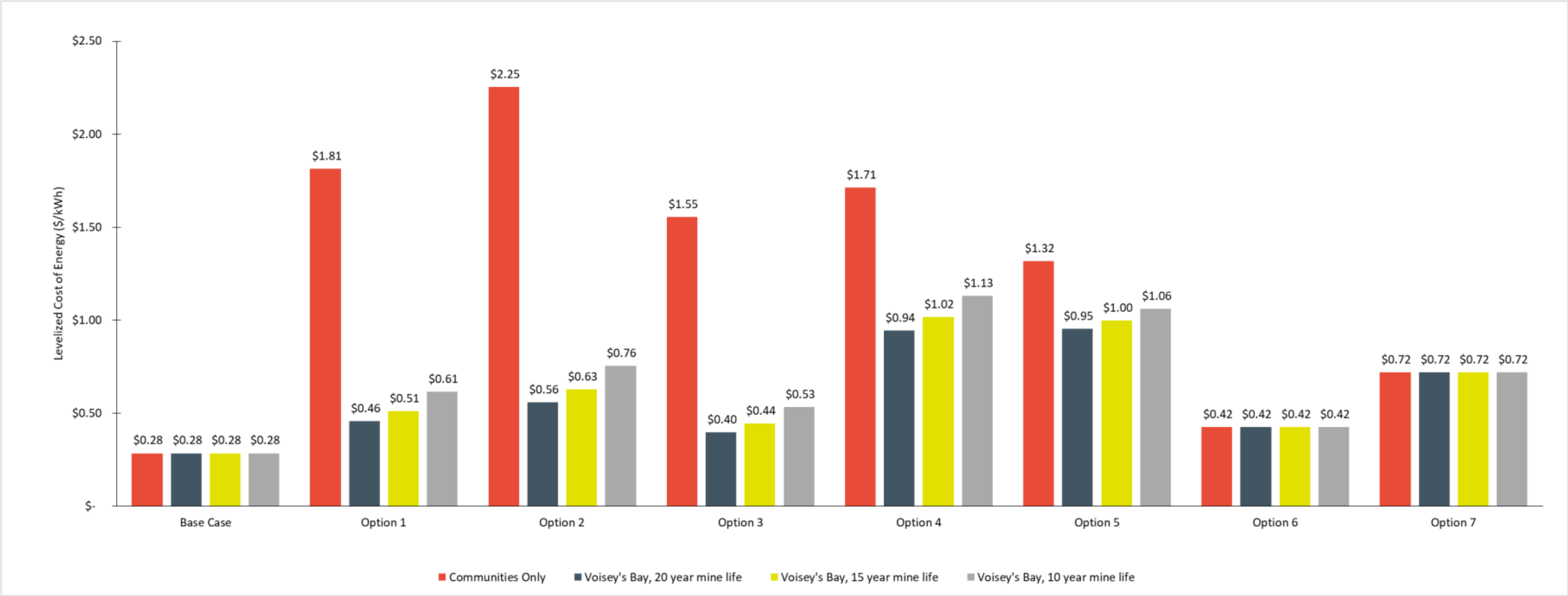


Figure 10-3: Estimated Levelized Cost of Energy for each Option for 4 scenarios, Energy Sales to Communities Only, 100% Voisey's Bay (100% of electricity is served by hydro in Option 1-3, and 100% of excess electricity is sold to Voisey's Bay in Option 4-5), for 20 years, 15 years or 10 years of operation, depending on the mine life.

*additional diesel costs for Voisey's Bay to serve load are not considered.

Table 10-2: Comparison of Annual Energy Sales, Total Cost of Ownership (20 years) and Levelized Cost of Energy (20 years) for the Options under 3 different energy sales scenarios

	Communities Only			Voisey's Bay, 20 year mine life*			Voisey's Bay, 10 year mine life**			
Options	**Annual Energy Sales**	**TCO ($ M)**	**LCOE ($/kWh)**	**Annual Energy Sales**	**TCO ($ M)**	**LCOE ($/kWh)**	**Annual Energy Sales, year 1-10 ****	**Annual Energy Sales, year 11-20 ****	**TCO ($ M)**	**LCOE ($/kWh)**
Base Case	84,660 MWh/yr	$284 M	$0.28 /kWh	84,660 MWh/yr	$284 M	$0.28 /kWh	84,660 MWh/yr	84,660 MWh/yr	$284 M	$0.28 /kWh
Option 1	84,660 MWh/yr	$1,812 M	$1.81 /kWh	368,540 MWh/yr	$1,979 M	$0.46 /kWh	368,540 MWh/yr	84,660 MWh/yr	$1,979 M	$0.61 /kWh
Option 2	84,660 MWh/yr	$2,252 M	$2.25 /kWh	368,540 MWh/yr	$2,420 M	$0.56 /kWh	368,540 MWh/yr	84,660 MWh/yr	$2,420 M	$0.76 /kWh
Option 3	84,660 MWh/yr	$1,552 M	$1.55 /kWh	368,540 MWh/yr	$1,720 M	$0.40 /kWh	368,540 MWh/yr	84,660 MWh/yr	$1,720 M	$0.53 /kWh
Option 4	84,660 MWh/yr	$1,712 M	$1.71 /kWh	153,620 MWh/yr	$1,712 M	$0.94 /kWh	153,620 MWh/yr	84,660 MWh/yr	$1,712 M	$1.13 /kWh
Option 5	84,660 MWh/yr	$1,315 M	$1.32 /kWh	116,820 MWh/yr	$1,315 M	$0.95 /kWh	116,820 MWh/yr	84,660 MWh/yr	$1,315 M	$1.06 /kWh
Option 6	84,660 MWh/yr	$423 M	$0.42 /kWh	84,660 MWh/yr	$423 M	$0.42 /kWh	84,660 MWh/yr	84,660 MWh/yr	$423 M	$0.42 /kWh
Option 7	84,660 MWh/yr	$717 M	$0.72 /kWh	84,660 MWh/yr	$717 M	$0.72 /kWh	84,660 MWh/yr	84,660 MWh/yr	$717 M	$0.72 /kWh

*100% of the electricity needs of Voisey's Bay are served in Option 1-3 by hydropower, and 100% of the excess electricity in the North is sold to Voisey's Bay in Option 4-5 for the entire 20-year period

**100% of the electricity needs of Voisey's Bay are served in Option 1-3 by hydropower, and 100% of the excess electricity in the North is sold to Voisey's Bay in Option 4-5 for the first 10 years of the 20 year study period, Annual Energy Sales and Total Operating Costs reduce to Communities Only year 11-20.

10.2 Comparison of North and South Communities

For the different Options, the total cost of ownership was split to assess the differences between the North Communities and the South Communities. The North Communities are Nain, Natuashish, Hopedale, Makkovik, Postville and Rigolet. The South Communities are Cartwright, Paradise River, Black Tickle, Norman Bay, Charlottetown, Port Hope Simpson, Mary's Harbour, Saint Lewis, and L'Anse-au-Loop.

Capital costs and operating costs were split between the north and south for each of the Options. However, Option 4 has been excluded since it relies on a single generation hub in the north to serve all communities. As such, it is not possible to allocate a portion of the generation cost to the south and a portion to the north.

Additionally, for the fully interconnected Options 1-3, the cost associated with the transmission losses needed to be divided between the North and South. The losses are continuously varying parameters that depends on number of factors including line voltage, line loading/current, line resistance, design of the system, and therefore are not easily split specially on these fully interconnected options.

The approach on the above Options is to estimate (high-level) the cost of losses. A split of 70% of the total cost of losses was allocated to the north and 30% of the total cost of losses was allocated to the south, since the south has considerably lower loading than the north. It should be noted that if there is the desire to build only an interconnection in the north or only in the south, a detailed assessment of losses would need to be conducted to get a more accurate estimate.

The total cost of ownership, split between the north and south, is shown in Figure 10-4. Across all Options, except Option 6, the total cost of ownership for the southern communities is lower than the northern communities, which is expected since the northern communities are more remote. The spread is greater for the interconnected options due to the more extensive transmission network and the higher voltage of the network proposed for the north.

For Option 6, the total cost of ownership for the south communities is slightly higher than the north. This is due to the greater number of communities in the south, thus more batteries and wind turbines are required. However, the variation of $6 M over the 20-year study period is well within the accuracy of this assessment.

The base case and Option 6 present the lowest cost options for both the north and the south communities. Option 7 is also comparable to the base case and Option 6 for the south communities.

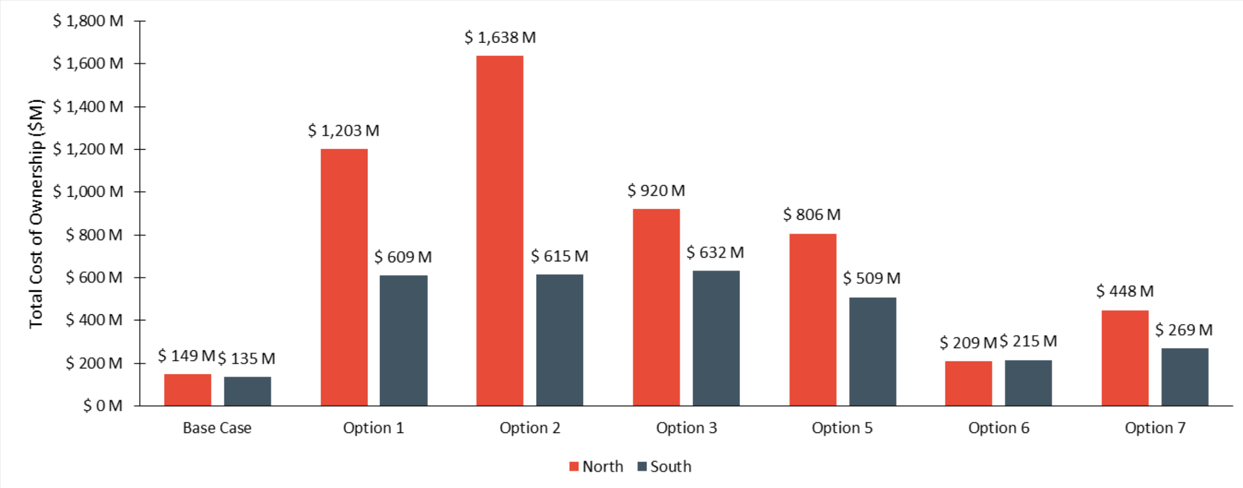


Figure 10-4: Comparison of Total Cost of Ownership for 20-year study period, splitting costs between the North and South Communities.

10.3 Comparison on an Individual Community Basis

For Options 6 and 7, there are some communities that have higher fuel costs, which could justify the installation of renewable generation. Therefore, the following section compares the base case, and Options 6 and 7 on an individual community basis.

A comparison of the total cost of ownership (TCO) in $M per community between Option 6 and the Base case, is presented in Figure 10-5 and Table 10-3. In all communities, the base case has a lower total cost of ownership. However, for some of the communities, the costs are quite similar (Nain, Natuashish). The percentage increase in total cost of ownership for each community is shown in Table 10-3. For the larger communities, the incremental cost to integrate renewables is closer; however, there is considerable added cost for the smaller communities, such as Norman's Bay, Black Tickle and Paradise River. This is reasonable, since these communities would require a smaller turbine, which is more costly per kW of capacity.

It may be possible that for some of the communities, installing 1 fewer wind turbines (e.g. in Hopedale, Makkovik, Cartwright) and having a lower RE% penetration could result in a comparable or even lower TCO compared to the base case. Each community should be investigated at greater detail if there is interest to install a wind + storage microgrid.

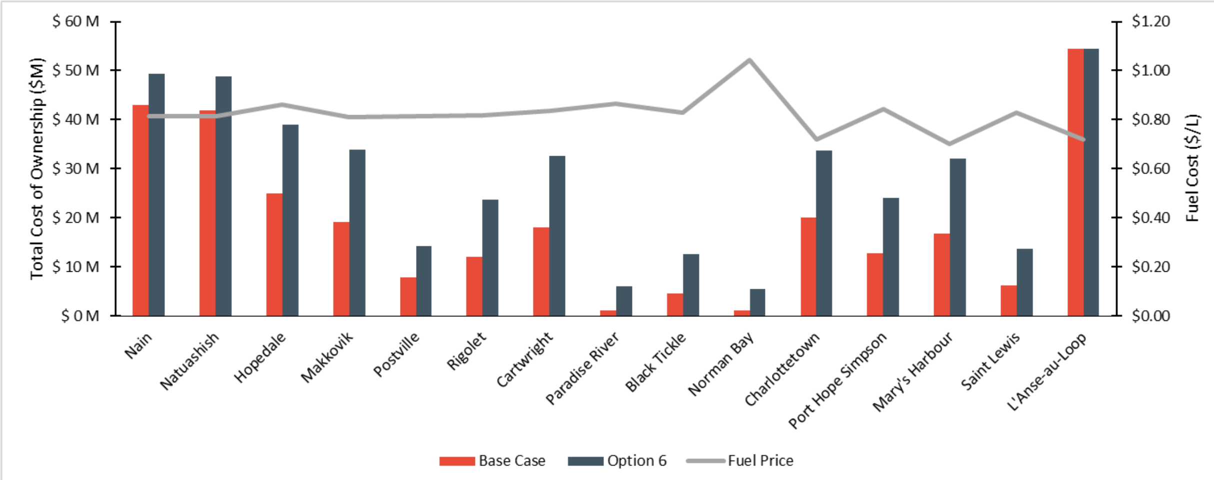


Figure 10-5: Comparison of Option 6 and the Base Case per community.

Table 10-3: Comparison of the Total Cost of Ownership ($M) for the Base Case and Option 6 per Community and the percentage Increase

Community	Base Case	Option 6	Percentage Increase
Nain	$43.1 M	$49.4 M	15%
Natuashish	$41.9 M	$48.8 M	17%
Hopedale	$24.9 M	$39.1 M	57%
Makkovik	$19.1 M	$33.9 M	77%
Postville	$7.9 M	$14.1 M	79%
Rigolet	$12.1 M	$23.7 M	96%
Cartwright	$18.1 M	$32.7 M	81%
Paradise River	$1.2 M	$5.9 M	407%
Black Tickle	$4.5 M	$12.5 M	175%
Norman Bay	$1.1 M	$5.5 M	388%
Charlottetown	$20.1 M	$33.7 M	68%
Port Hope Simpson	$12.7 M	$24.1 M	90%
Mary's Harbour	$16.8 M	$33.0 M	91%
Saint Lewis	$6.1 M	$13.7 M	124%
L'Anse-au-Loop	$54.4 M	$54.4 M	0%

A comparison of the total cost of ownership (TCO) in $M per community cluster based on the microgrid in Option 7 between Option 6, Option 7 and the Base case, is presented in Table 10-4 and Figure 10-6.

Again, the base case has the lowest total cost of ownership. Additionally, Option 6 has a lower cost compared to Option 7. However, with the connection of the communities there are added benefits in terms of reliability. Therefore, in some specific cases, such as the Port Hope Simpson Microgrid, or the Cartwright and Paradise River Microgrid, connecting the communities provides added secondary benefits for the small communities, which are not necessarily economically quantifiable.

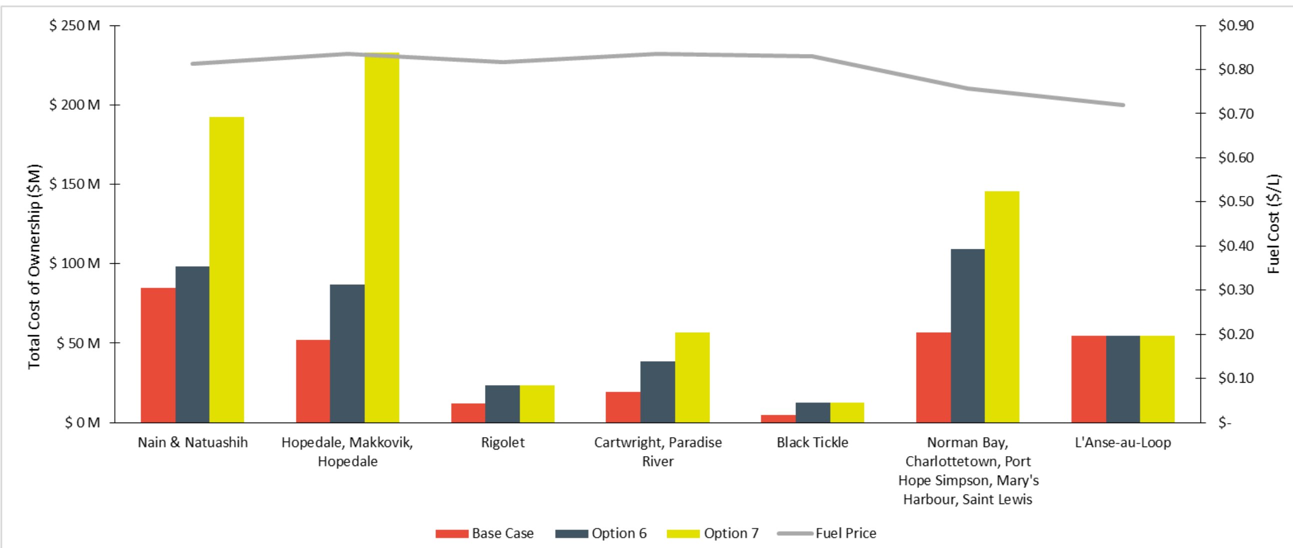


Figure 10-6: Comparison of Option 6 and the Base Case per community cluster.

Table 10-4: Comparison of the Total Cost of Ownership ($M) for the Base Case and Option 6 and 7 per Community Cluster and the percentage Increase

Community	Base Case	Option 6	Option 7	Percentage Increase from the Base Case for Option 6	Percentage Increase from the Base Case for Option 7
Nain & Natuashish	$84.9 M	$98.2 M	$192.6M	16%	127%
Hopedale, Makkovik, Hopedale	$51.9 M	$87.1 M	$232.9 M	68%	349%
Rigolet	$12.1 M	$23.7 M	$23.7 M	96%	96%
Cartwright, Paradise River	$19.3M	$38.6 M	$56.8 M	101%	195%
Black Tickle	$4.5 M	$12.5 M	$12.5 M	175%	175%
Norman Bay, Charlottetown, Port Hope Simpson, Mary's Harbour, Saint Lewis	$56.8 M	$109.0 M	$145.6 M	92%	157%
L'Anse-au-Loop	$54.4 M	$54.4 M	$54.4 M	0%	0%

10.4 Sensitivity Analysis

A sensitivity analysis was performed on the total ownership cost with respect to CAPEX and OPEX variables. This results of this analysis for each of the scenarios is summarized in Table 10-5 and the percentage difference is presented in Table 10-6.

Table 10-5: TCO Sensitivity Analysis (M$)

		TCO Sensitivity Analysis (M$)															
	Basis	T&D CAPEX		Generation CAPEX		Transmission OPEX		Losses OPEX		Generation OPEX		Fuel Cost		Diesel OPEX		Discount Rate	
Options	0%	-50%	50%	-50%	50%	-50%	50%	-50%	50%	-50%	50%	-50%	50%	-50%	50%	-50%	50%
Base Case	$284	$284	$284	$284	$284	$284	$284	$284	$284	$284	$284	$203	$365	$245	$323	$364	$228
Option 1	$1,812	$993	$2,631	$1,812	$1,812	$1,767	$1,857	$1,795	$1,829	$1,812	$1,812	$1,812	$1,812	$1,812	$1,812	$1,861	$1,778
Option 2	$2,252	1,234	$3,271	$2,252	$2,252	$2,195	$2,310	$2,227	$2,278	$2,252	$2,252	$2,252	$2,252	$2,252	$2,252	$2,313	$2,210
Option 3	$1,552	$892	$2,213	$1,552	$1,552	$1,516	$1,588	$1,498	$1,607	$1,552	$1,552	$1,552	$1,552	$1,552	$1,552	$1,617	$1,507
Option 4	$1,712	$1,052	$2,373	$1,645	$1,780	$1,676	$1,748	$1,706	$1,719	$1,696	$1,728	$1,673	$1,751	$1,694	$1,731	$1,784	$1,662
Option 5	$1,315	$842	$1,787	$1,245	$1,384	$1,289	$1,341	$1,312	$1,318	$1,298	$1,331	$1,276	$1,354	$1,296	$1,333	$1,380	$1,269
Option 6	$423	$423	$423	$330	$517	$423	$423	$423	$423	$390	$457	$381	$466	$403	$444	$490	$377
Option 7	$717	$551	$883	$644	$790	$708	$727	$717	$717	$692	$742	$675	$759	$697	$737	$784	$670

Table 10-6: TCO Sensitivity Analysis (%)

	TCO Sensitivity Analysis (%)															
	T&D CAPEX		Generation CAPEX		Transmission OPEX		Losses OPEX		Generation OPEX		Fuel Cost		Diesel OPEX		Discount Rate	
Options	-50%	50%	-50%	50%	-50%	50%	-50%	50%	-50%	50%	-50%	50%	-50%	50%	-50%	50%
Base Case	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	-29%	29%	-14%	14%	28%	-20%
Option 1	-45%	45%	0%	0%	-3%	3%	-1%	1%	0%	0%	0%	0%	0%	0%	3%	-2%
Option 2	-45%	45%	0%	0%	-3%	3%	-1%	1%	0%	0%	0%	0%	0%	0%	3%	-2%
Option 3	-43%	43%	0%	0%	-2%	2%	-4%	4%	0%	0%	0%	0%	0%	0%	4%	-3%
Option 4	-39%	39%	-4%	4%	-2%	2%	0%	0%	-1%	1%	-2%	2%	-1%	1%	4%	-3%
Option 5	-36%	36%	-5%	5%	-2%	2%	0%	0%	-1%	1%	-3%	3%	-1%	1%	5%	-3%
Option 6	0%	0%	-22%	22%	0%	0%	0%	0%	-8%	8%	-10%	10%	-5%	5%	16%	-11%
Option 7	-23%	23%	-10%	10%	-1%	1%	0%	0%	-4%	4%	-6%	6%	-3%	3%	9%	-7%

It can be seen from the above that while the total cost of ownership in the base case is highly dependent on fuel costs, the TCO for Options 1-5 is highly dependent on T&D capital costs. Option 6 is most dependent on generation capital costs and is also affected by fuel costs and generation OPEX to a lesser degree. Option 7 is most dependent on T&D capital costs, with generation capital costs and fuel costs affecting TCO to a lesser degree. The discount rate also has significant impact on the Base Case and Option 6, as these are affected by fuel costs and annual operating costs.

The impact of the significant cost variables on the total ownership cost of each scenario is further illustrated in Figure 10-7 to Figure 10-12 below.

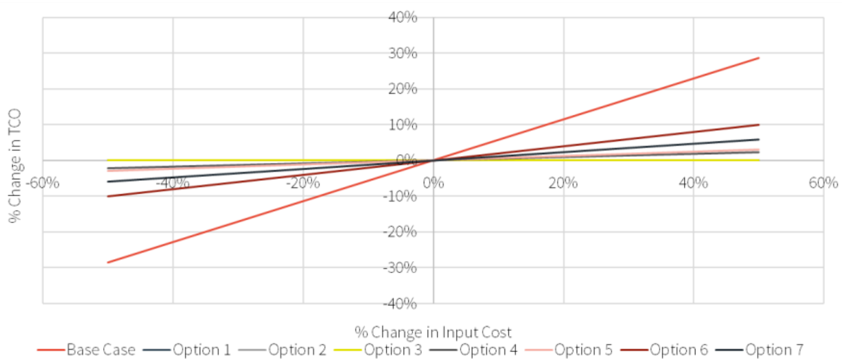


Figure 10-7: Sensitivity to Fuel Cost

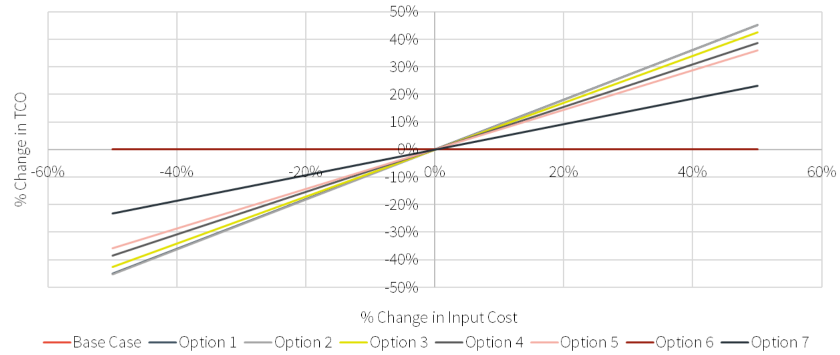


Figure 10-9: Sensitivity to T&D CAPEX

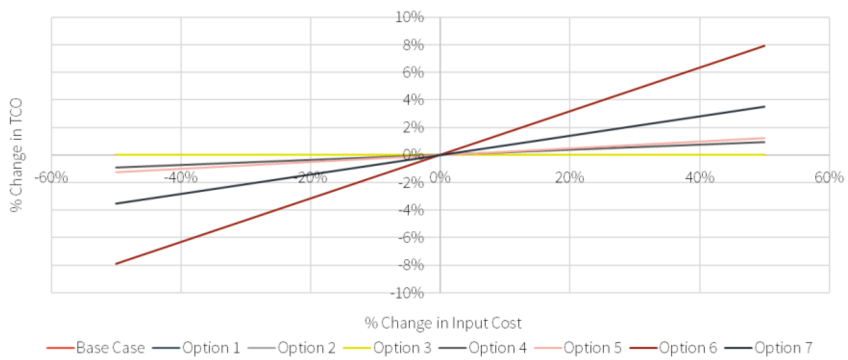


Figure 10-8: Sensitivity to Generation OPEX

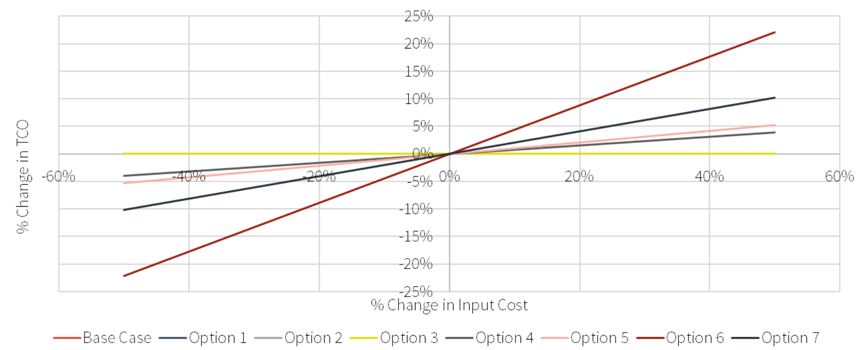


Figure 10-10: Sensitivity to Generation CAPEX

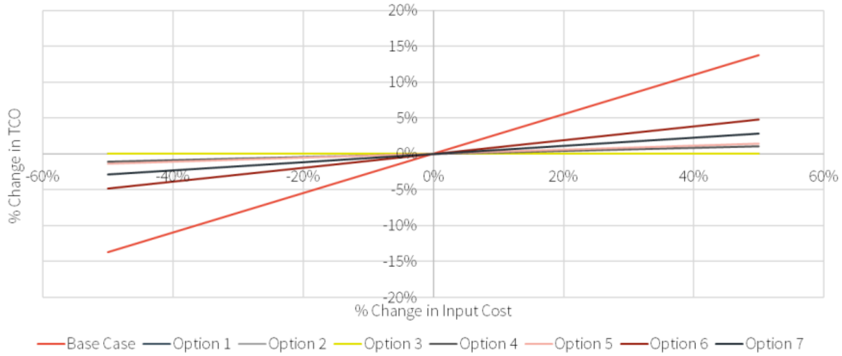


Figure 10-11: Sensitivity to Diesel OPEX

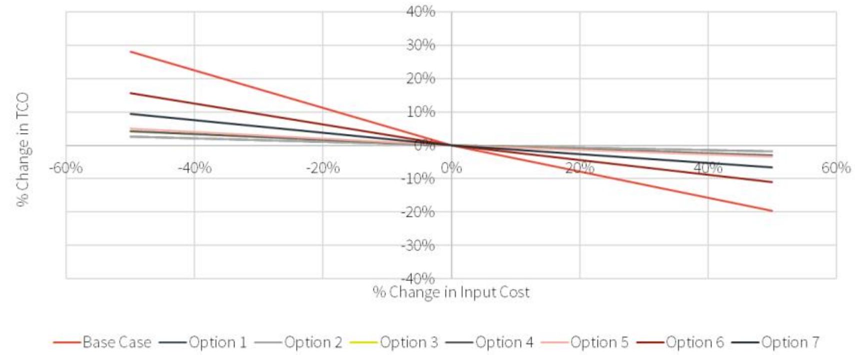


Figure 10-12: Sensitivity to Discount Rate

Overall, the two largest factors determining project economic viability under the range of scenarios are capital costs and fuel costs. Long-term fuel costs are uncertain, especially given the unexpected drop in price and demand during 2020, due to in part to the COVID-19 pandemic and in part due to OPEC's variations in production quantities. This fuel cost uncertainty has the greatest impact on the status-quo scenario and impacts Options 6&7 to a lesser degree. The impact of the fuel price forecast is also captured in the discount rate, since fuel costs are the highest annual cost. Capital costs play a significant role in all Options being considered, with transmission infrastructure costs being the dominant factor in Options 1-5 and 7. It is worth noting that decarbonization is a major priority for federal and provincial governments, and it may be possible to fund in part some of this capital requirement through grants or concessional financing available to projects that achieve a GHG reduction benefit. Figure 10-13 and Figure 10-14 provide an enlarged view of the sensitivity curves for CAPEX.

If funding is received to offset a portion of the capital costs, particularly for Option 6, the total cost of ownership approaches that of the base case, dropping to $330 M for a 50% reduction in generation CAPEX. Given fuel prices are at a low value in 2020, it is possible that in the future, with higher fuel prices, Option 6 could be more economic than the base case.

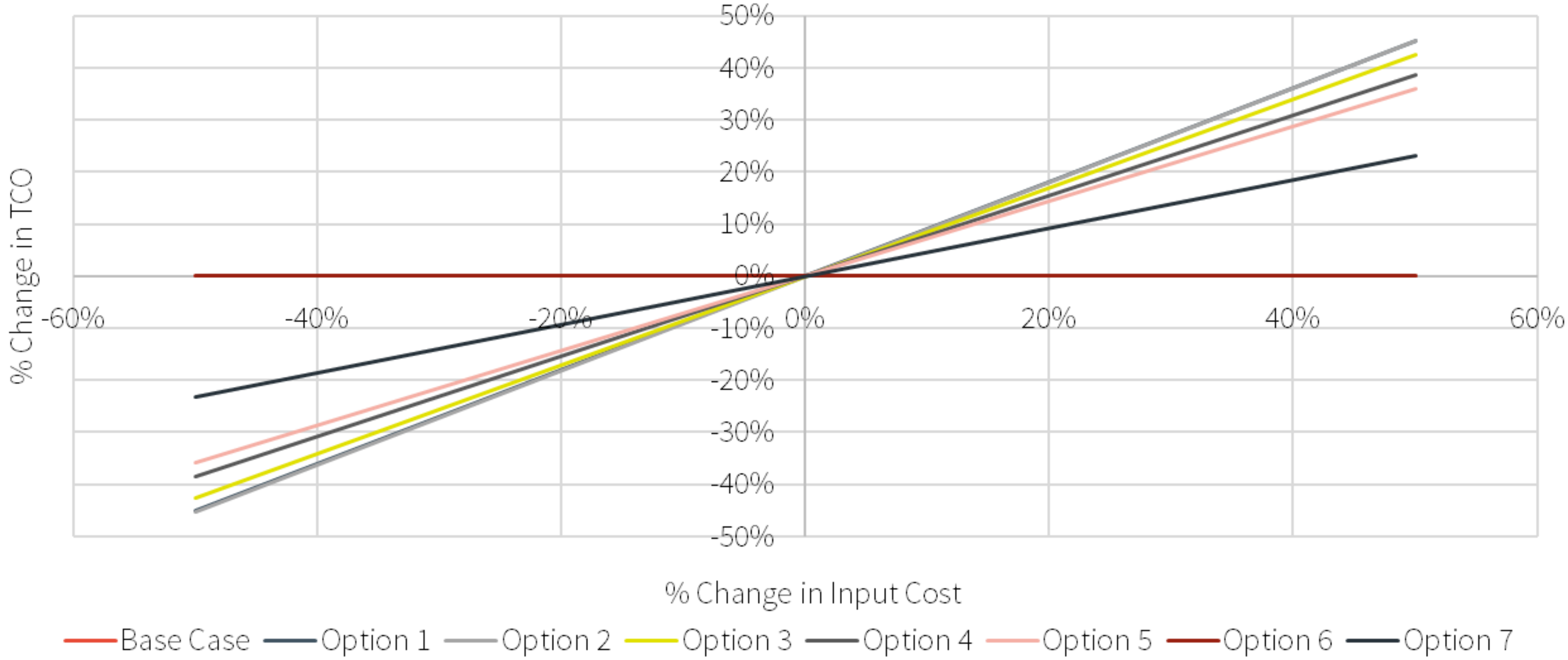


Figure 10-13: TCO Sensitivity to T&D CAPEX

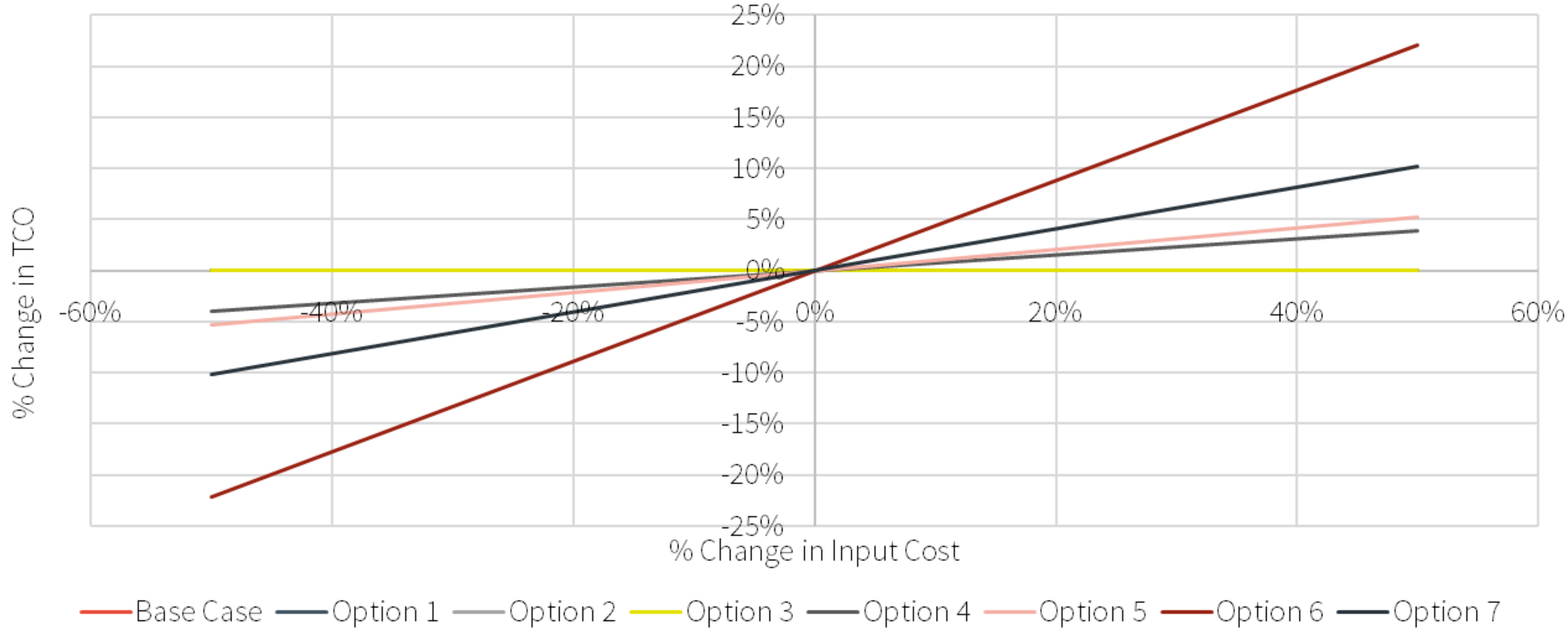


Figure 10-14: TCO Sensitivity to Generation CAPEX

10.5 40-year study period

The project study period was extended to 40 years as part of the sensitivity assessment for this analysis. Since transmission and distribution infrastructure have a lifetime of longer than 20 years, this assessment was included to determine if the study period would impact the conclusions.

As outlined in Section 7.2, the operating cost for the transmission & distribution lines, as well as the substation are increased to cover more repair and replacement costs required after 20 years of operation. Additionally, a replacement cost for the batteries was included at year 20, and a repowering cost for the wind turbines was included at year 30. Diesel genset operating costs were also increased to account for major overhaul costs.

The 40-year total cost of ownership is presented in Figure 10-15. The interconnected options continue to remain higher in total cost of ownership, due to the high upfront capital investment.

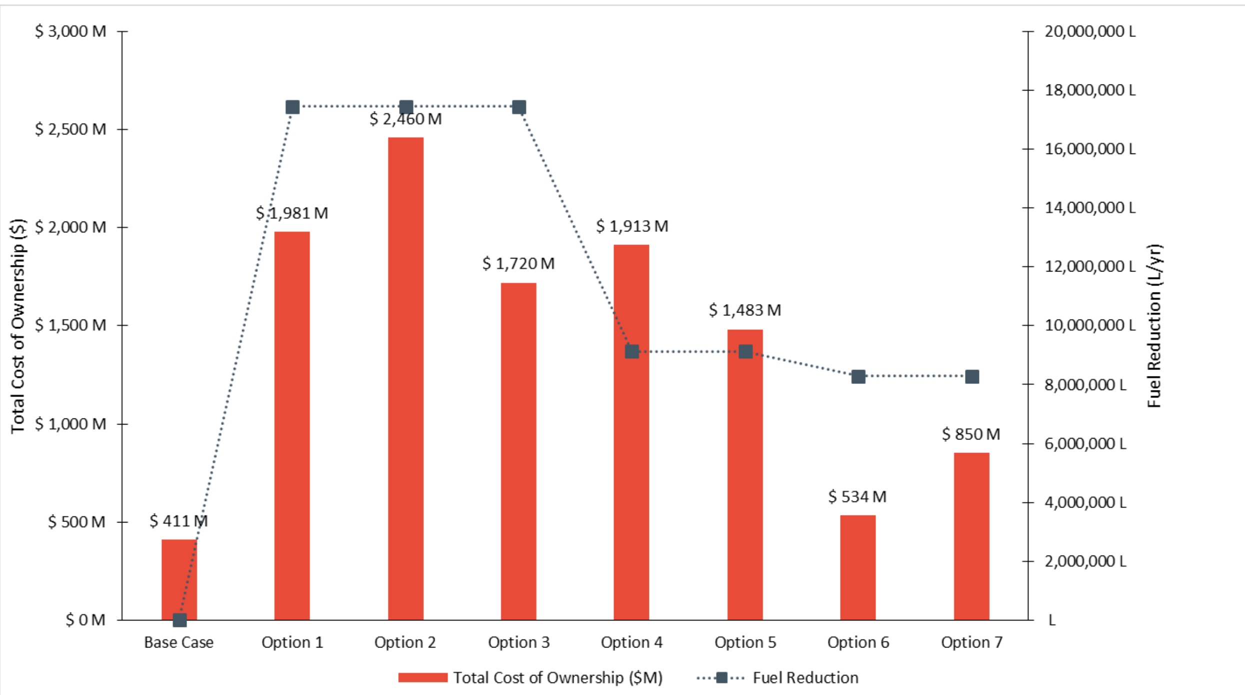


Figure 10-15: Comparison of Total Cost of Ownership to Annual Fuel Reduction for 40-year study period.

As with the 20-year study period, the LCOE for various mine life scenarios was investigated. Under the 40-year study periods, mine life of 10, 20, and 25 years were investigated. The 25 year mine life is highly unlikely, as Voisey's Bay has indicated that they do not expect operations to continue significantly beyond 30 years (from 2020), even with potential mine life extensions. Therefore, the transmission line would need to be built and operational within the next few years to achieve this scenario. The estimated LCOEs for the different Options under the different mine life scenarios are presented in Figure 10-16. The results show that with the consideration for the added OPEX and sustaining CAPEX to achieve a 40-year study period, Option 6 continues to remain the lowest LCOE, outside of the Base Case.

If the transmission line can serve 100% of Voisey's Bay's electricity needs for 25 years, then Option 3 has an LCOE of $0.02/kWh lower than Option 6. However, as outlined above, this would require that this transmission line is constructed and operational in the next 5 years, and for Voisey's Bay to continue to operate for 30 years (from 2020). This is a risk for NL Hydro, as they do not have control over the decision of the mine to extend its life.

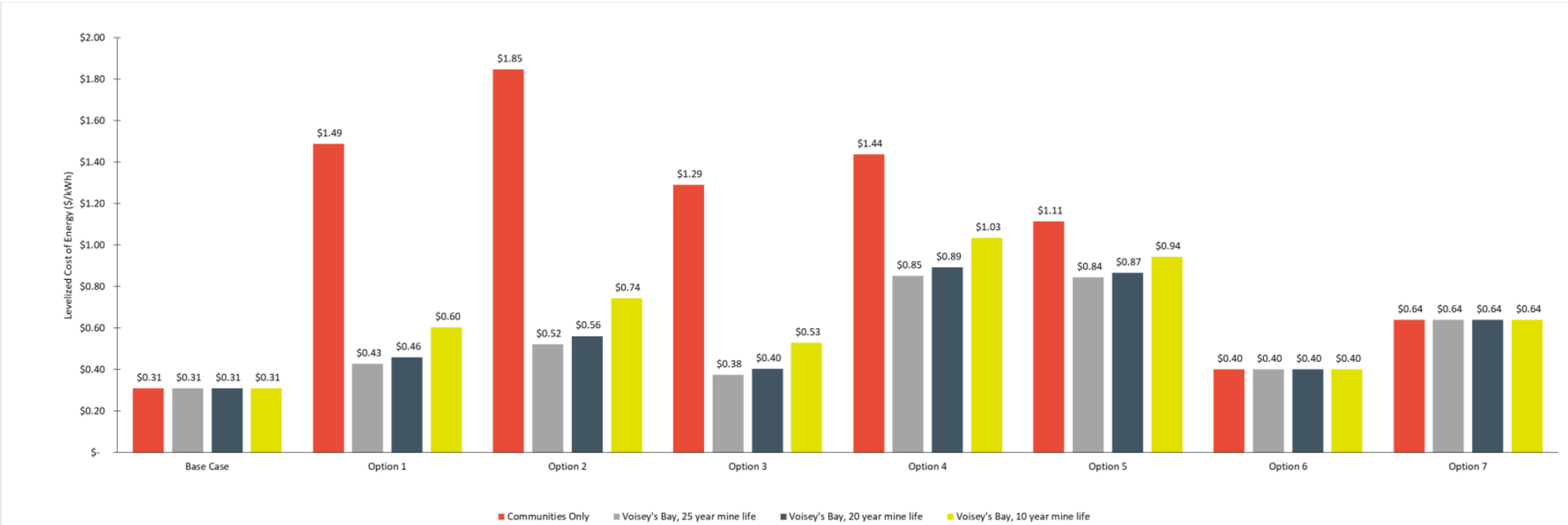


Figure 10-16: Estimated Levelized Cost of Energy for each Option for a 40-year study period, for 4 scenarios, Energy Sales to Communities Only, 100% Voisey's Bay (100% of electricity is served by hydro in Option 1-3, and 100% of excess electricity is sold to Voisey's Bay in Option 4-5), for 25 years, 20 years or 10 years of operation, depending on the mine life.

*additional diesel costs for Voisey's Bay to serve load are not considered.

11. Options Comparison

A summary comparing the different Options is presented in Table 11-1. There are benefits and drawbacks to each of the different Options. While the fully interconnected Options offer the greatest potential to reduce diesel fuel consumption, these Options come with the highest capital cost. Additionally, there is lowered reliability with these Options, since there is either a single transmission line or a transmission loop serving the communities. Due to the remote nature of these communities, it is likely that an outage would last for an extended period of time.

By contrast, the microgrid Options offer lower capital and operating costs; however, with the current assumptions there is only an offset of approximately 40-50% of the diesel fuel consumed. Therefore, if these Options are selected, NL Hydro will need to continue to maintain the engines in the communities and supply fuel on a regular basis.

There are many different factors that must be considered when selecting the preferred Option for NL Hydro to reduce diesel fuel usage and GHG emissions when supplying electricity to the 15 isolated communities in Labrador.

Table 11-1: Summary Comparison of the 7 Options across Various Metrics

Option	Generation Requirements	Diesel Fuel Reduction	Operability considerations	Reliability Considerations	Capital Cost	Annual Operating Cost	Total Cost of Ownership (20 year)
Base Case	0 MW	0 M L/yr	Continue to operate 3-4 engines in each community. Operability is the same as current.	Continued supply with only diesel in communities Reliability will be the same as current operations, with genset outages being the greatest source	$0 M	$24.1 M	$284 M
Option 1	0 MW	17.5 M L/yr	Maintenance would shift to substation inspections and preventative maintenance. Additionally, NL Hydro would need to maintain the	Redundant design in North South design is reasonable given accessibility Black Tickle & Norman Bay are likely the most vulnerable	$1,637 M	$14.8 M	$1,812 M

Option	Generation Requirements	Diesel Fuel Reduction	Operability considerations	Reliability Considerations	Capital Cost	Annual Operating Cost	Total Cost of Ownership (20 year)
Option 2	0 MW	17.5 M L/yr	transmission lines. In the north this would be icing management and the south a greater focus would need to be placed on vegetation management. These interconnected Options also experience considerable losses. In Option 3, some operating condition might result in stability issues under post contingency scenario	North is redundant, but using a parallel path leaves vulnerability in extreme weather South same as Option 1	$2,037 M	$18.3 M	$2,252 M
Option 3	0 MW	17.5 M L/yr		No redundancy in the North; however, reliability improved if VB can cover a portion of the load during outages South same as Option 1 May elect to keep the community gensets as backup	$1,321 M	$19.6 M	$1,552 M
Option 4	38.5 MW Wind	9.1 M L/yr	Substation and the transmission lines running from Voisey's Bay to the communities must be maintained. Additionally, generation at Voisey's Bay must be operated and maintained. When Voisey's Bay shuts down, a battery will be needed to manage wind variability. NL Hydro may elect to engage an IPP to own, operate and maintain the renewable generation.	System has little redundancy and centrally located renewable generation Keeping diesel gensets as backup in the communities improves reliability System is vulnerable to outage with low windspeed, since renewables in single location	$1,456 M	$21.7 M	$1,712 M

Option	Generation Requirements	Diesel Fuel Reduction	Operability considerations	Reliability Considerations	Capital Cost	Annual Operating Cost	Total Cost of Ownership (20 year)
Option 5	38.5 MW Wind, 3.5 MW Storage	9.1 M L/yr	North microgrid has the same considerations as Option 4. Operability of south microgrid requires maintenance of a centralized wind + storage hub and the transmission/distribution network. This Option eliminates the 300 km transmission connection or Muskrat Intersection switching station, which lowers transmission associated O&M requirements/costs. NL Hydro may elect to engage an IPP to own, operate and maintain the renewable generation and storage for both the north and south.	North microgrid is the same as Option 4. The reliability of the south microgrid depends on the location of the wind generation. If located at Port Hope Simpson, reliability will be higher since the wind is centralized and there are several radial lines serving 1-3 communities. If wind generation is located in Cartwright, there would be 1 radial line serving all communities, lowering the reliability. Again, keeping diesel gensets in each community improves reliability considerably.	$1,084 M	$19.6 M	$1,315 M
Option 6	25.9 MW Wind, 12.6 MW Storage	8.3 M L/yr	Many small microgrids which need O&M services, likely to have an IPP program to reduce burden on NL Hydro	Reliability is comparable to current design, with all generation within the community.	$187 M	$20.0 M	$423 M
Option 7	25.8 MW Wind, 12.4 MW Storage	8.3 M L/y	Fewer wind + battery installations lead to lower maintenance requirements; however, short run	Reliability improved slightly over base case, if gensets remain in each community. If there is a generation	$480 M	$20.2 M	$717 M

Option	Generation Requirements	Diesel Fuel Reduction	Operability considerations	Reliability Considerations	Capital Cost	Annual Operating Cost	Total Cost of Ownership (20 year)
			transmission lines must now be maintained. Again, may elect to engage an IPP to own and operate the wind + storage to reduce burden on NL Hydro.	outage in one community, gensets can from other communities can be used as backup. If transmission connection is down, then gensets within each community can supply. In some cases, reliability may be unaffected by a regional power plant (or improved). This would need to be assessed on a case-by-case basis in a more detailed study.			

A 3.5 MW turbine was used as a template turbine for this study. Currently, 3.5 MW to 4.2 MW turbines are the largest available options; however, turbine sizes are continually increasing. Typically, new turbine models are developed every 2-3 years. If one of these options moves forward, the assessment should be completed in greater detail using the wind turbine technology that is the state-of-the-art at the time of assessment.

12. Conclusions

Reducing diesel dependence for the 15 isolated communities in Labrador is important to reduce energy associated emissions and reduce the high and variable costs associated with diesel fuel.

This report assesses 7 different Options to reduce diesel emissions in the communities, ranging from fully interconnected Options to microgrids with integrated wind + storage.

Option 1 and 3 both have benefits and limitations for the fully interconnected Options. Option 1 has a higher reliability in the North, with the loop configuration, but has a higher total cost of ownership. By contrast, Option 3 has lower reliability with 2 radial lines from Happy Valley (one north and one south) and high losses; however, this Option has a lower total cost of ownership. The reliability of Option 3 can be improved by keeping the diesel gensets in the community as backup.

Option 2 has the highest total cost of ownership. Additionally, running the parallel line increases reliability; however, does not improve reliability in the event of a storm or a pole going down. This Option seems to be less desirable due to the high capital cost, high operating cost, and the marginal gains in reliability compared to Option 3.

Option 4 also has a high total cost of ownership and only offsets approximately 50% of the diesel fuel consumption. Option 4 also has a long radial connection which will have high losses and leave the communities in the south vulnerable to outages. Option 4 is also less desirable due to the low reliability for delivery of renewable generation, the lower reduction in diesel consumption, and the high cost.

Option 5 also has some benefits and limitations. By having a centrally located large wind farm in both the south and north, economies of scale can be achieved to reduce the unit capital cost and unit operating costs for this Option. As well, having generation in both the north and south eliminates the need for long transmission connections (~488 km) to connect the communities to Happy Valley, considerably reducing the CAPEX. However, Option 5 only reduces the diesel fuel consumption by approximately 50% (except L'Anse-au-Loop). There are still reliability concerns with delivery of wind from the central windfarm to the communities along radial transmission networks (this is mitigated by keeping diesel generation within the communities). Though losses are reduced by eliminating the long interconnections, there is still considerable losses in both systems because of the extensive network.

Option 6 is the lowest cost Option; with 1-3 wind turbines and a battery storage system located in every community. However, in this Option, 50% of the generation continues to be supplied by diesel fuel (except L'Anse-au-Loop). As well, there is high operating requirements, needing maintenance of 14 wind farms. If NL Hydro elects to go with this Option, it seems most probable that an independent power producer will be selected to own and operate each wind farm (and potentially the energy storage). This Option eliminates the need for costly transmission lines.

Option 7 is another viable option, blending the benefits of connecting the communities while reducing the high costs associated with long transmission lines. This Option improves reliability by connecting several communities in 4 microgrids. This reduces the number of wind farms from 14 to 6, which reduces the operating burden and the number of energy storage systems required. Additionally, the larger microgrids allow for larger turbines to be used, lowering the unit capital costs and the operating cost per kWh generated – which ultimately lowers the marginal energy costs. However, the main limitation of this Option is that it has lower diesel reduction and GHG reductions. As well, 3 communities (Rigolet, Black Tickle, and L'Anse-au-Loop) remain isolated due to the high cost of the transmission lines to connect these communities.

The lowest cost Option is the base case operation, keeping the diesel gensets within each community. This Option has an approximate total lifecycle cost of approximately $140 M less than Option 6. However, continuing with the base case results in the highest GHG emissions, which does not support overall provincial and national initiatives to reduce emissions and fossil fuel dependence. Additionally, this Option has the highest volatility in pricing, since the cost of generation is directly tied to the price of diesel fuel. Thus, when global oil prices are higher, the cost of generation will increase. Lastly, the cost of major overhauls and engine replacements have not been considered. Therefore, this will likely bring the base case closer in cost to Option 6 and 7. Costs associated with fuel subsidies (or future carbon pricing if it becomes applicable to isolated communities) have not been considered; therefore, the true cost of the base case may be higher than the other options if all the subsidies and cost of emissions are considered.

As outlined above, there are benefits and drawbacks to each Option. Several different metrics, including technical, economic, community preferences, and social and environmental considerations, must be assessed in order to identify one or more preferred Options.

12.1 Next Steps

As outlined above, there are several benefits and limitations to each of the Options which must be considered and weighed to determine the preferred path forward. Some of the next steps may include:

- Select preferred 2-3 Options for a more detailed prefeasibility study.
- Explore opportunities to increase renewable energy penetration in Option 6, in order to further reduce diesel fuel consumption.
- Determine studies required to assess environmental impact of extended transmission lines for Options 1-5 & 7, such as:

    - Extensive environmental impact studies will likely be required to understand the impact on native/migratory species, native vegetation, ground and surface water, and local cultural/heritage sites and archeological artifacts.
    - Since Option 7 only has short transmission connections, the environmental assessment would be less extensive than Options 1-5.
- Explore IPP programs/renewable integration opportunities to understand interest/costs.
- Assess need to upgrade distribution voltage level within the communities.
- Community Consultations to understand desires of the community members.
- Assessment of soil contamination if planning to decommission diesel gensets.
- Wind monitoring campaign, particularly in the south, to select preferred sites.
- Discussions with Vale regarding future of Voisey's Bay and the potential connection Options.

Appendix A
Capital Cost Estimate Memo

Project Memo

H-362861

June 26, 2020

To: John Flynn, NL Hydro

From: Jocelyn Zuliani and David Anders

cc: Rob Collett, NL Hydro
Michel Carreau, Hatch
Dan Kell, Hatch

Newfoundland and Labrador Hydro
Labrador Interconnections Options Study

Estimated Capital Costs

1. Introduction

The following memo outlines the proposed Unit Costs for the Labrador Interconnection Options Study.

1.1 Unit Cost Review for NL Hydro Interconnection

High level unit costs for major transmission/distribution system components was estimated at a class 5 level, based on information provided by NL Hydro, published information and subject matter experts.

The following general NL Hydro initial estimates were considered, based on the February 17, 2016 memo "Labrador Interconnection – Preliminary Study – Cost Estimate Update", and have been further refined.

Table 1-1: Capital Cost Estimates from NL Hydro's Interconnection Study in 2016

System Component	2016 Value	Updated 2020 Value
138kV OH Transmission Line	$995,000/km	See breakdown below
69kV OH Transmission Line	$765,000/km	See breakdown below
25kV OH Distribution Line	$197,000/km	See breakdown below
HV terminal stations	$10,100,000	See breakdown below
Distribution Stations	$7,100,100	See breakdown below
Mobile Substations	$4,600,000	$4,900,000 (adjusted for annual inflation rate of ~1.7%)
Mobile Substation (Lab South)	$5,100,000	$5,500,000 (adjusted for annual inflation rate of ~1.7%)
69kV Line tap	$2,500,000	Estimated value

2. Current Cost Estimates

2.1 Source for Updated Costs

Substation costs were estimated based on values reported in “Unit Cost Estimates for Transmission Lines and Facilities in Northern Ontario and the Far North”, prepared by SNC Lavalin for the Ontario Power Authority, October 18, 2011.[1] The costs estimated in this report reflect installation conditions and infrastructure types which are expected to be similar to the NL hydro interconnection project. Reported costs were adjusted +10% based on inflation (+20%) and the expected construction cost differential between Ontario and NL (-10%).

For the northern loop, the “Far North” cost basis was used, which assumes temporary access roads required for 100% of route and heavy brushing for 75% of route. For the southern loop, the “Northern Ontario” cost basis was used, which assumes 50% of route requires installation of temporary access roads, and 50% heavy brushing of line routes.

All costs include overhead and contingency. Land acquisition / ROW land rental costs have not been included in these estimates.

2.2 Substation Costs

The following summarizes the high-level substation cost estimates proposed for the study. Base costs cited in SNC Lavalin, 2011 have been adjusted based on the assumptions above as well as on:

- Number of transformers
- Number of line terminations
- Voltage levels
- Power capacity

Note: Reactive power compensation (e.g. shunt reactor/synchronous condensers) will likely be required for some of the scenarios. The pricing for these components has note been completed yet. It will be provided at a later date.

[1] http://www.ieso.ca/-/media/Files/IESO/Document-Library/regional-planning/North-of-Dryden/App-1-1-3-Transmission-Unit-Cost-Study-SNC-Lavalin.pdf?la=en

Table 2-1: Estimated Substation Costs for each Community

	Station Name	Description	No. of line terminations (Primary)	No. of line terminations (Secondary)	Capital Cost Estimation
Northern Loop	Churchill Falls	230 kV to 138 kV; 1 x 37.5/50/62 MVA	1	1	$7,500,000
	Nain	25 kV to 4.16 kV; 2 x 3.75/5/6 MVA	2	1	$3,900,000
	Natuashish	138 kV to 25 kV; 2 x 3.75/5/6 MVA	2	1	$9,100,000
	Hopedale	138 kV to 4.16 kV; 2 x 2/2.7/3.3 MVA	2	1	$6,300,000
	Postville	138 kV to 4.16 kV; 2 x 1.5/2/2.5 MVA	2	1	$5,900,000
	Makkovik	138 kV to 4.16 kV 2 x 1.5/2/2.5 MVA	2	1	$5,900,000
	Rigolet	138 kV to 4.16 kV 2 x 1.5/2/2.5 MVA	2	1	$5,900,000
Southern Loop	Muskrat Falls Intersection	138 kV to 69 kV; 2 x 10/13.3/16.6 MVA	2	1	$9,800,000
	Paradise River*	69 kV to 4.16 kV; 1 x 1.5/2/2.5 MVA	1	1	$4,900,000
	Generation Substation	15MVA, 69kV - Expansion to substation at Port Hope or Mary's Harbour to allow for generation	1	1	$1,800,000
	Cartwright	69 kV to 4.16 kV; 1 x 1.5/2/2.5 MVA	1	1	$4,900,000
	Black Tickle I	69 kV to 25 kV; 1 x 1.5/2/2.5 MVA	1	1	$6,100,000
	Black Tickle II	25 kV to 4.16 kV; 1 x 1.5/2/2.5 MVA	1	1	$2,400,000
	Port Hope Simpson	69 kV to 25 kV - 12.5 kV; 2 x 2/2.7/3.3 MVA	2	2	$7,400,000
	Charlottetown*	25 kV to 4.16 kV; 1 x 2/2.7/3.3 MVA	1	1	$2,800,000
	Norman Bay	25 kV to 4.16 kV; 1 x 1.5/2/2.5 MVA	1	1	$2,400,000
	St. Lewis	25 kV to 12.5 kV; 1 x 1.5/2/2.5 MVA	1	1	$3,400,000
	Mary's Harbour*	69 kV to 4.16 kV; 1 x 1.5/2/2.5 MVA	1	1	$4,900,000
	L'Anse-Au-Loop	69 kV to 25 kV; 1 x 5/6.7/8.3 MVA	1	1	$6,700,000

*It is assumed that the transmission/distribution line is tapped to enter these substations with a single termination.

2.3 Transmission and Distribution Lines Costs

The following summarizes the high-level unit cost estimates proposed for transmission/distribution lines included in the study. Base costs cited in SNC Lavalin, 2011 have been adjusted based on the assumptions above as well as on voltage levels.

In the case of the 25kV submarine connection, the published cost data for the Bell Island Submarine Cable Replacement (2013) was used as a reference given the geographic proximity and similar interconnection voltage and length.[2]

Table 2-2: Summary of Unit Costs for Transmission and Distribution Systems

	Run	Voltage	Conductor Size	Construction	Cost per km
Northern Loop	Transmission Lines in North, no road access so temporary road required	138 kV	559 kcmil, AAAC	H-Frame wood	$850,000
	Distribution line to Nain, no road access so temporary road required	25 kV	4/0 AASC	Single wood pole	$230,000
Southern Loop	Transmission Lines in South, existing road access. Lines follow existing roadways	138 kV	559 kcmil, AAAC	H-Frame wood	$680,000
		69 kV*	559 kcmil, AAAC	H-Frame wood	$580,000
		69 kV*	267 kcmil, ASCR	Single wood pole	$290,000
	Undersea cable to Black Tickle	25 kV	#1 XLPE sub cable	N/A	$3,500,000
	Distribution lines South, following existing roadways	25 kV	4/0 AASC	Single wood pole	$190,000

* The main 69 kV transmission line running between the Muskrat Falls Intersection and L'Anse-au-Loop is using Darien AAAC 559 kcmil Conductors, while the 69 kV lines servicing Paradise River, Cartwright, and Black Tickle is using a Partridge ACSR 267 kcmil Conductor due to the lower current. These were assumptions made by NL Hydro in their original study.

2 http://www.pub.nf.ca/applications/NP2014Capital/NPCBSUPP2014/BellIslandSubCable/application/Application-ApprovaltoReplacetheBellIslandSubmarineCable-2013-12-09.pdf

Table 2-3: Details on Transmission and Distribution Costs per Line

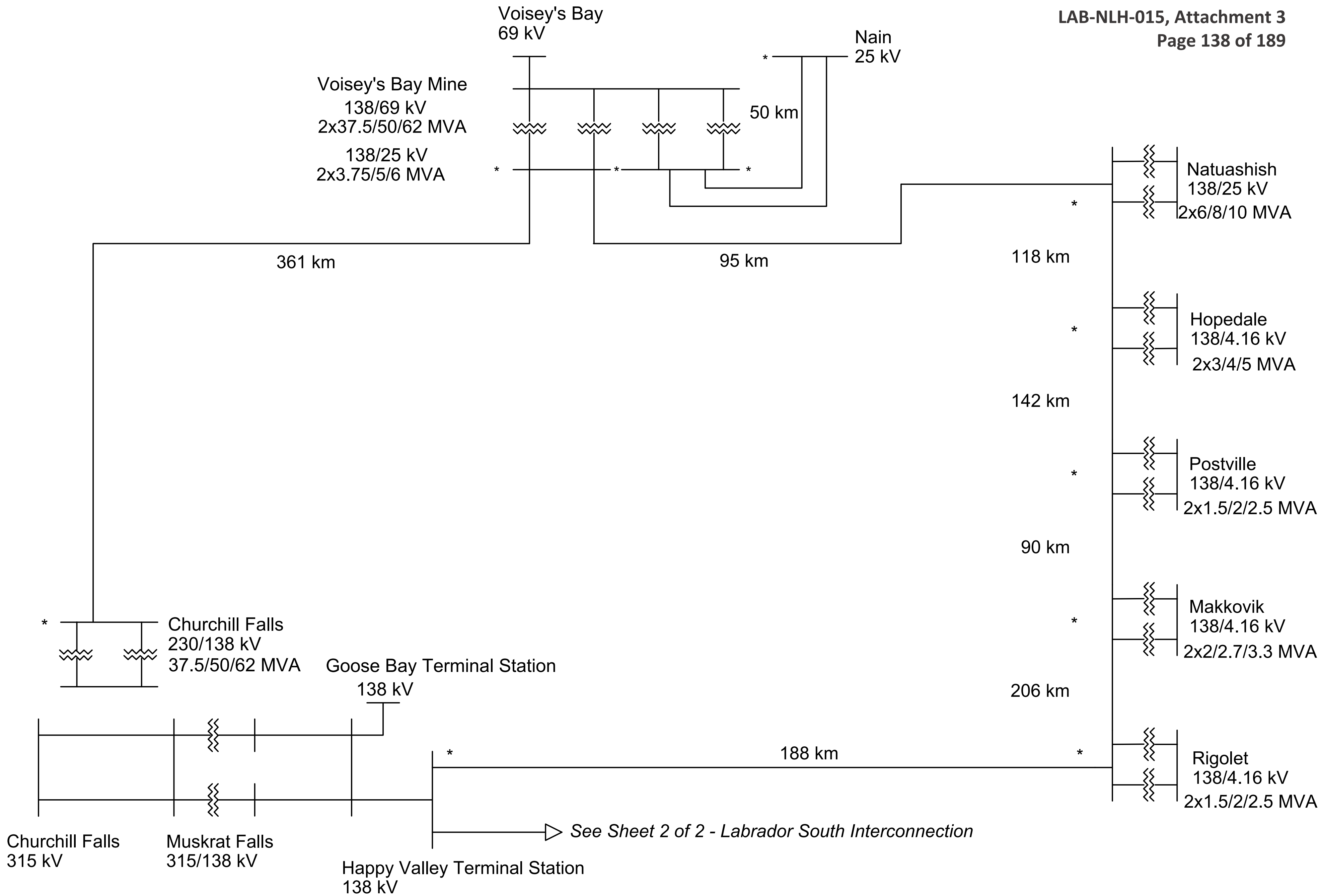
	Run	Voltage	Conductor Size	Construction	Cost per km
Northern Loop	Churchill Falls to VB	138 kV	559kcmil, AAAC	H-Frame wood	$850,000
	VB to Nain - 25 kV line	25 kV	4/0 AASC	Single wood pole	$230,000
	VB to Natuashish	138 kV	559kcmil, AAAC	H-Frame wood	$850,000
	Natuashish to Hopedale	138 kV	559kcmil, AAAC	H-Frame wood	$850,000
	Hopedale to Postville	138 kV	559kcmil, AAAC	H-Frame wood	$850,000
	Postville to Makkovik	138 kV	559kcmil, AAAC	H-Frame wood	$850,000
	Makkovik to Rigolet	138 kV	559kcmil, AAAC	H-Frame wood	$850,000
	Rigolet to HV Terminal - Muskrat Falls	138 kV	559kcmil, AAAC	H-Frame wood	$850,000
Southern Loop	HV-GB To Muskrat Falls Intersection	138 kV	559kcmil, AAAC	H-Frame wood	$680,000
	Muskrat Falls Intersection to Paradise River	69 kV	267kcmil, ASCR	Single wood pole	$290,000
	Paradise River to Junction	69 kV	267kcmil, ASCR	Single wood pole	$290,000
	Paradise River to Cartwright	69 kV	267kcmil, ASCR	Single wood pole	$290,000
	Junction to Charlottetown Tap	69 kV	267kcmil, ASCR	Single wood pole	$290,000
	Muskrat Falls Intersection to Charlottetown Tap	69 kV	559kcmil, AAAC	H-Frame wood	$580,000
	Charlottetown Tap to Black Tickle, last 3 km are underwater	69 kV	267kcmil, ASCR	Single wood pole	$290,000
		25 kV	#1 XLPE sub cable	N/A	$3,500,000
	Charlottetown Tap to Port Hope Simpson	69 kV	559kcmil, AAAC	H-Frame wood	$580,000
	Port Hope Simpson to Charlottetown	25 kV	4/0 AASC	Single wood pole	$190,000
	Charlottetown to Norman Bay	25 kV	4/0 AASC	Single wood pole	$190,000
	Port Hope Simpson to St. Lewis	25 kV	4/0 AASC	Single wood pole	$190,000
	Port Hope Simpson to Mary's Harbour	69 kV	559kcmil, AAAC	H-Frame wood pole	$580,000
	Mary's Harbour to L'Anse-au-Loop	69 kV	559kcmil, AAAC	H-Frame wood	$580,000

Appendix B
Single Line Diagrams

Figure 1: Option 1 SLD

Sheet 1: Northern Communities

Sheet 2: Southern Communities



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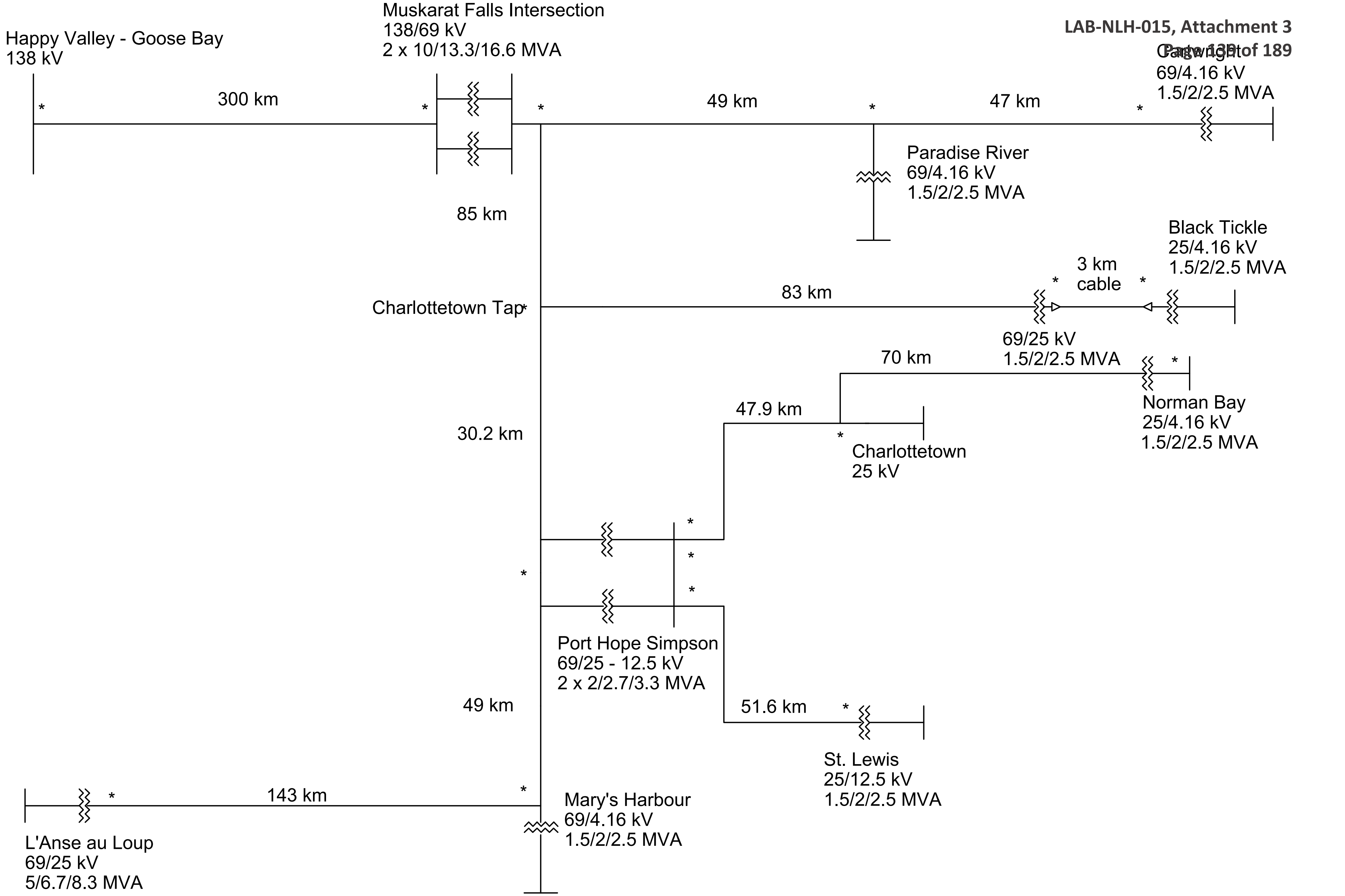
		July 30, 2020



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Labrador South Interconnection

Sheet 2 of 2

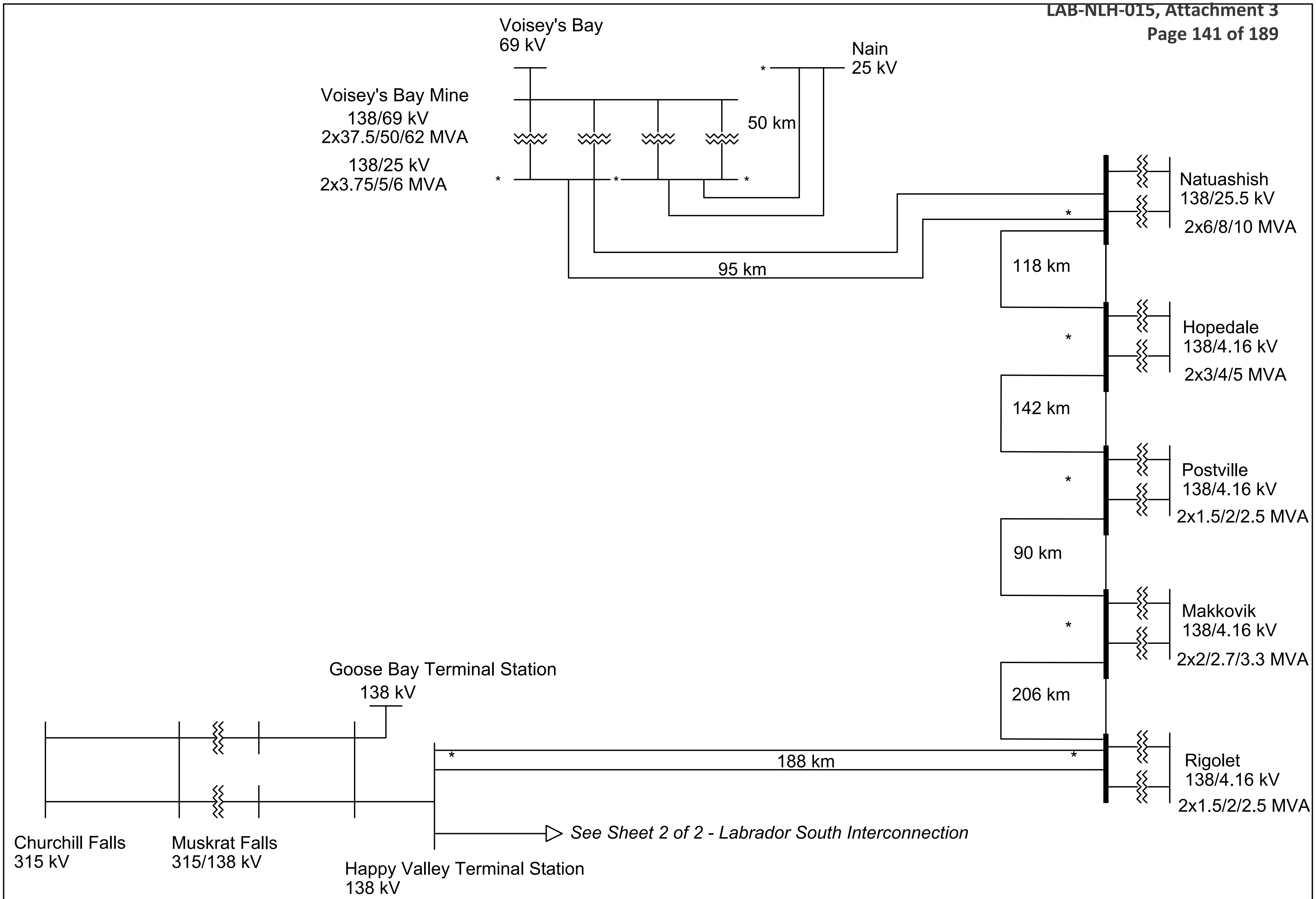
Drawn By: JRM

July 30, 2020

Figure 2: Option 2 SLD

Sheet 1: Northern Communities

Sheet 2: Southern Communities



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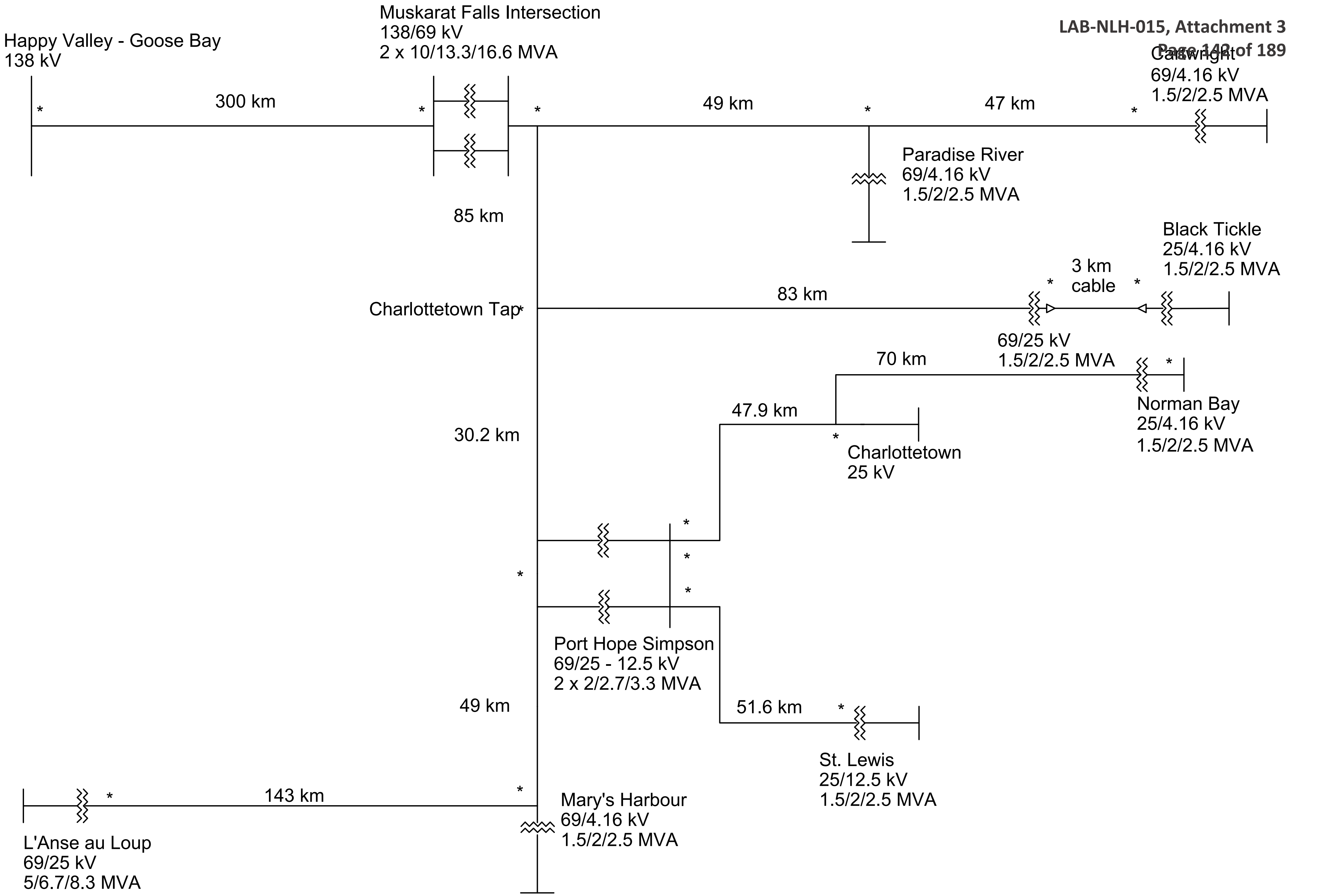
July 30, 2020



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Labrador South Interconnection

Sheet 2 of 2

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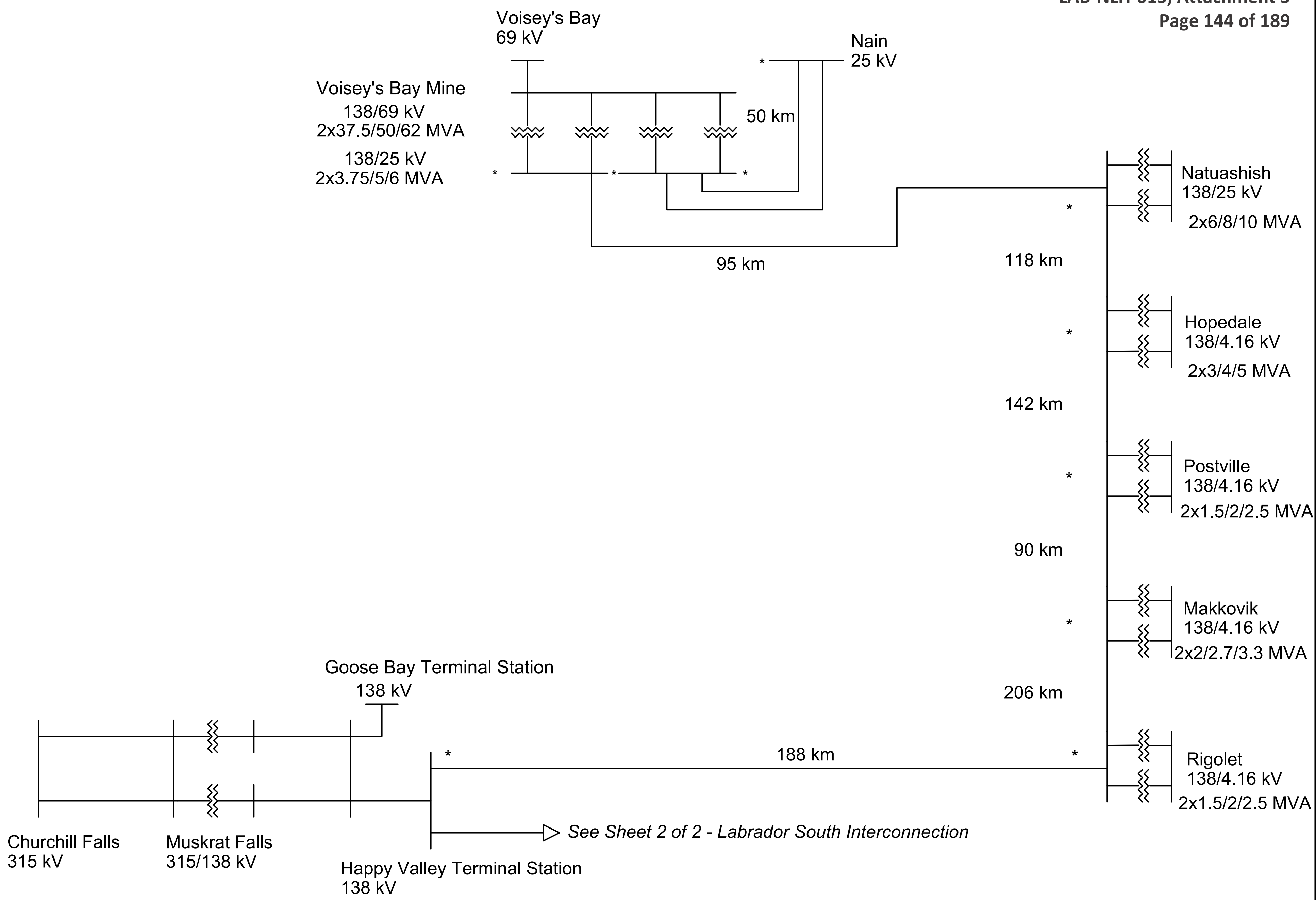
July 30, 2020

Figure 3: Option 3 SLD

Sheet 1: Northern Communities

Sheet 2: Southern Communities



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Labrador North Interconnection

Sheet 1 of 2

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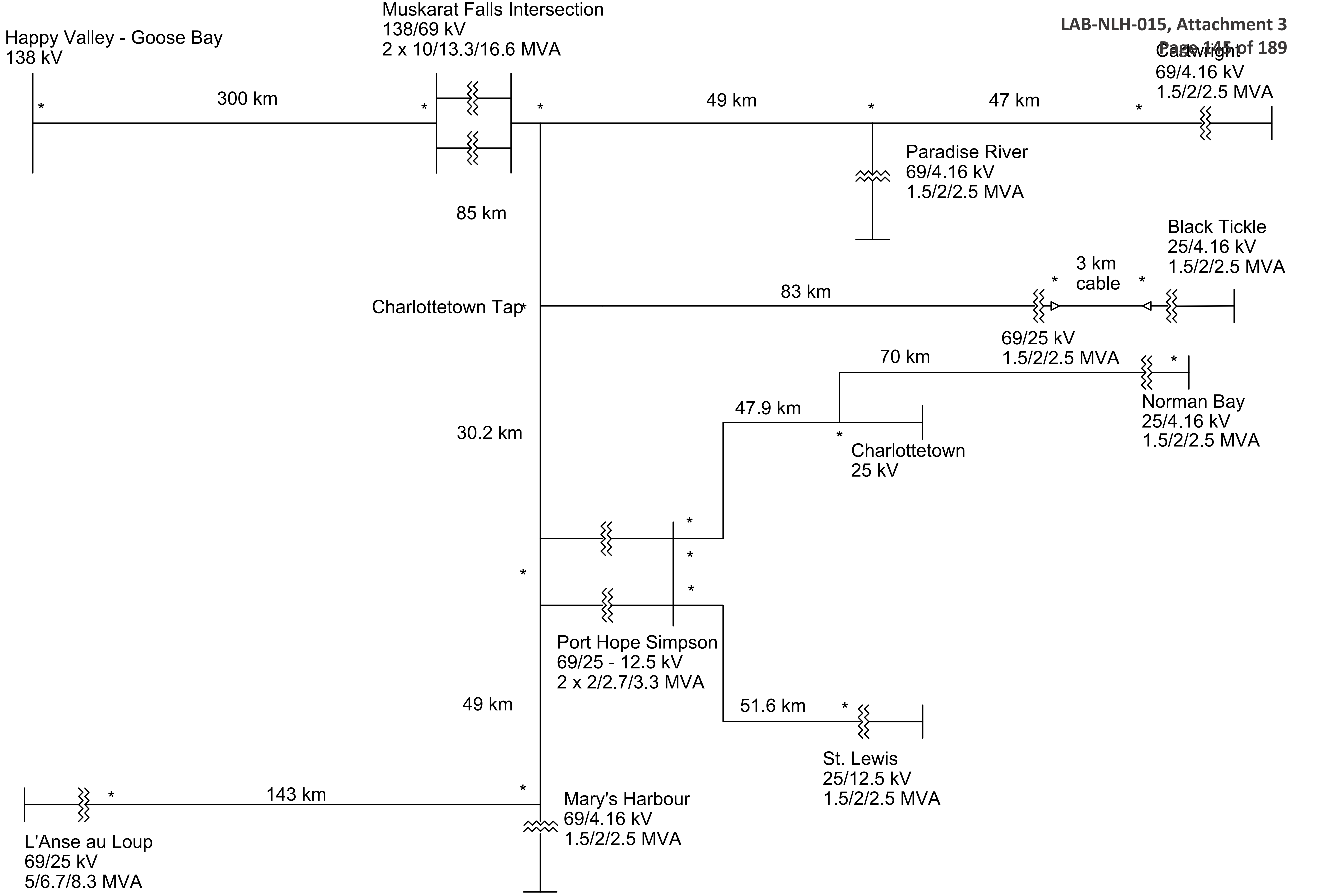
July 30, 2020

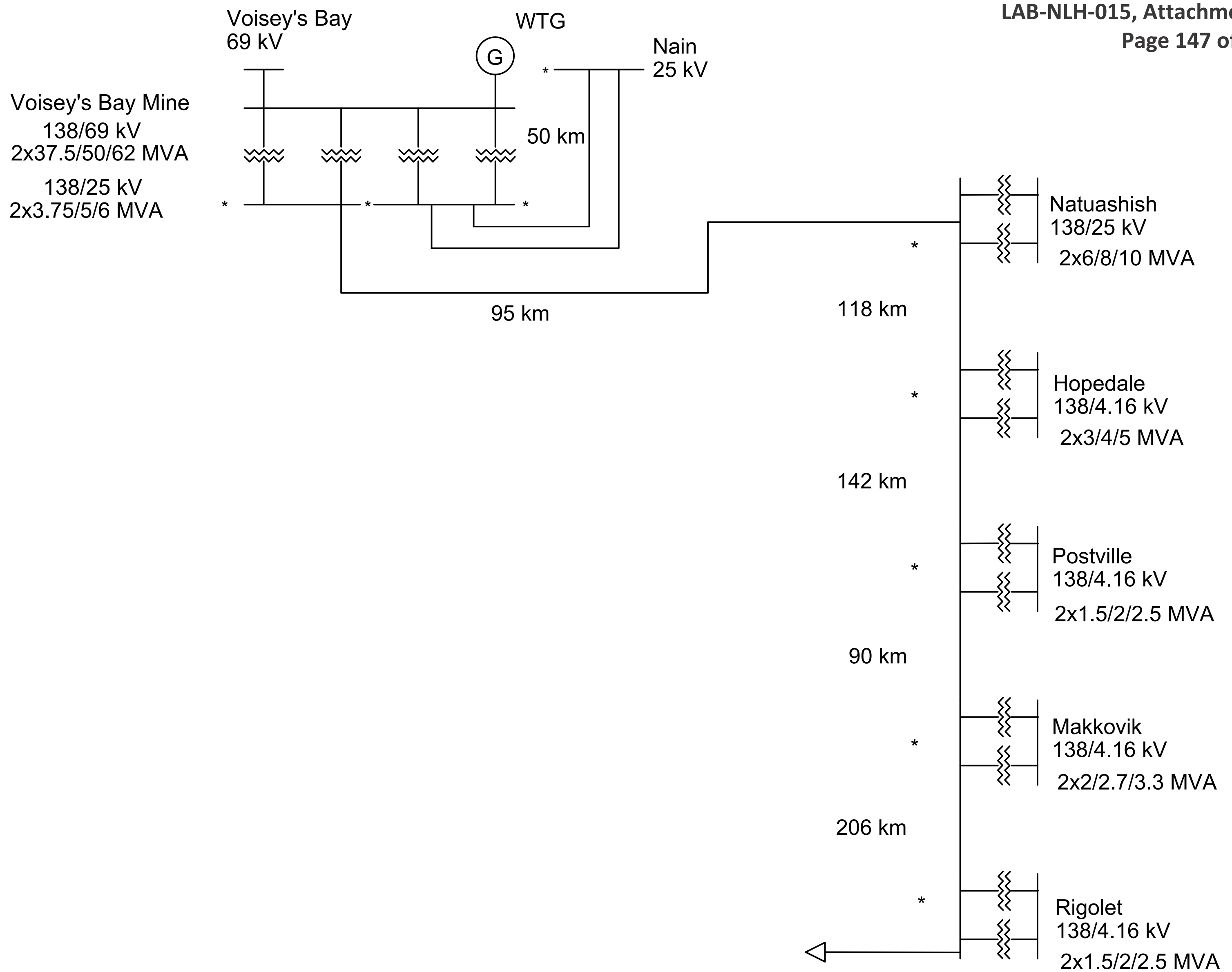


HYDRO	Labrador South Interconnection	Sheet 2 of 2
		Drawn By: JRM
		July 30, 2020

Figure 4: Option 4 SLD

Sheet 1: Northern Communities

Sheet 2: Southern Communities



See Sheet 2 of 2 - Labrador South Interconnection

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Labrador North Interconnection

Sheet 1 of 2	
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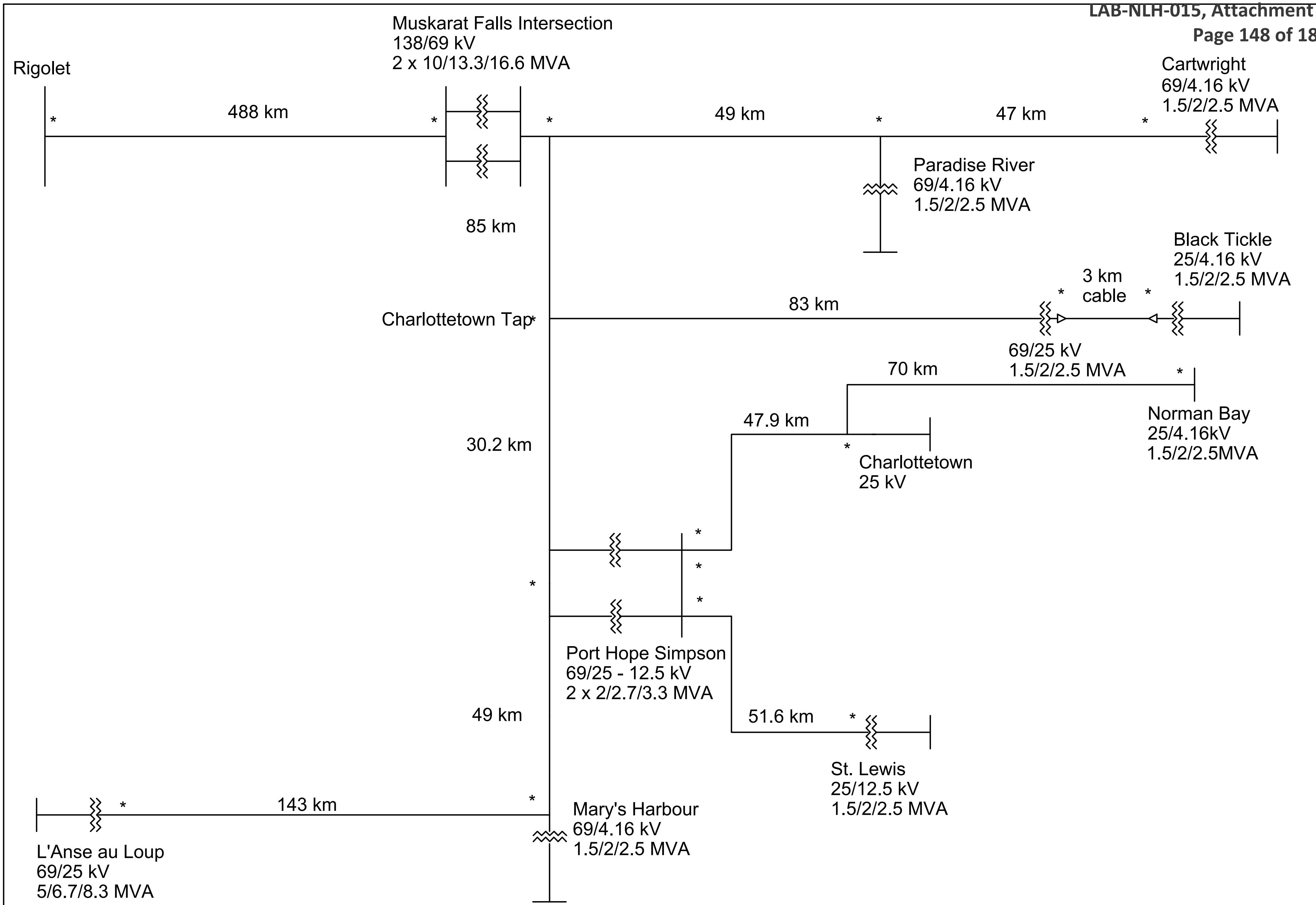
July 30, 2020	



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Labrador South Interconnection

Sheet 2 of 2

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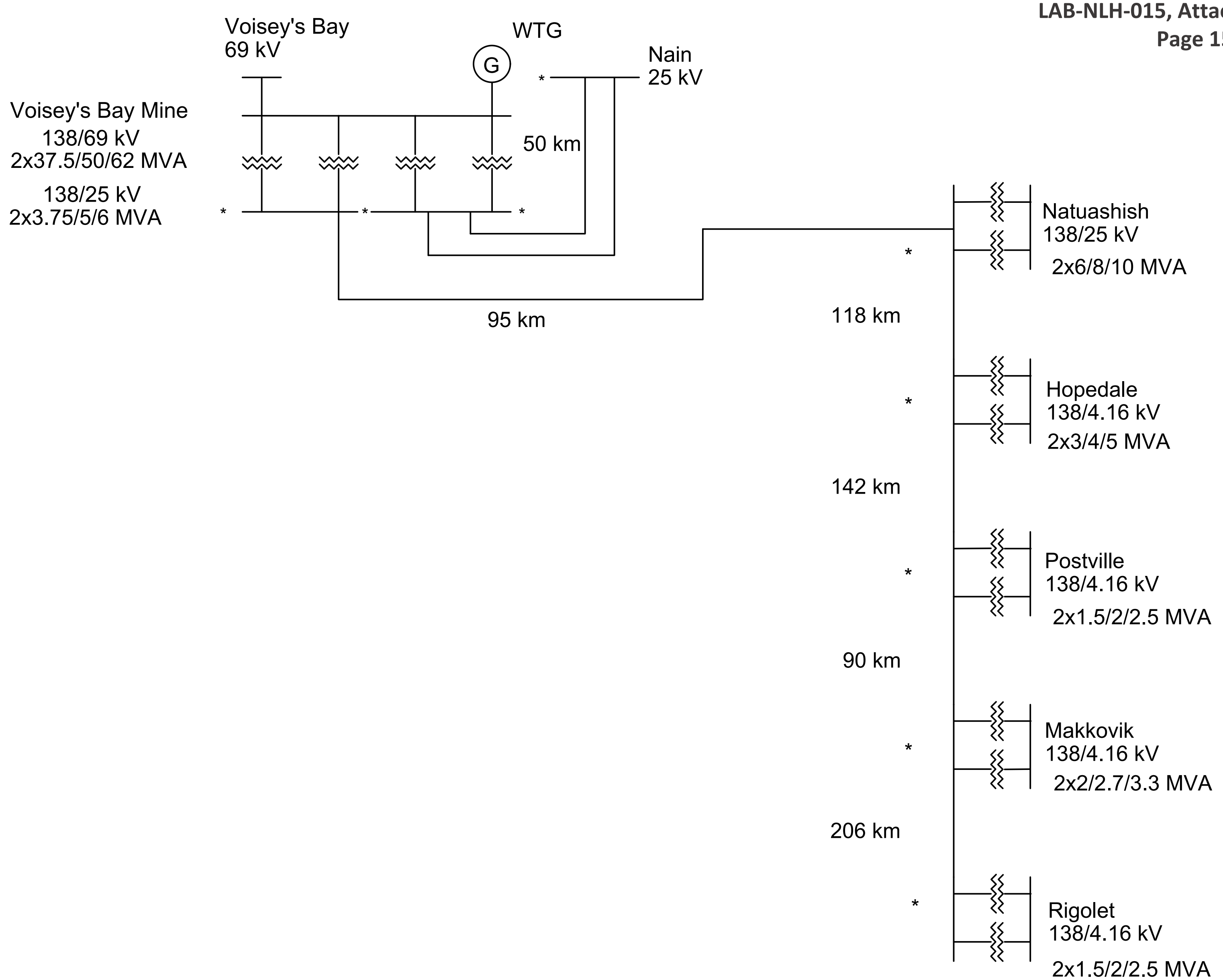
July 30, 2020

Figure 5: Option 5 SLD

Sheet 1: Northern Communities

Sheet 2: Southern Communities



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Labrador North Interconnection

Sheet 1 of 2

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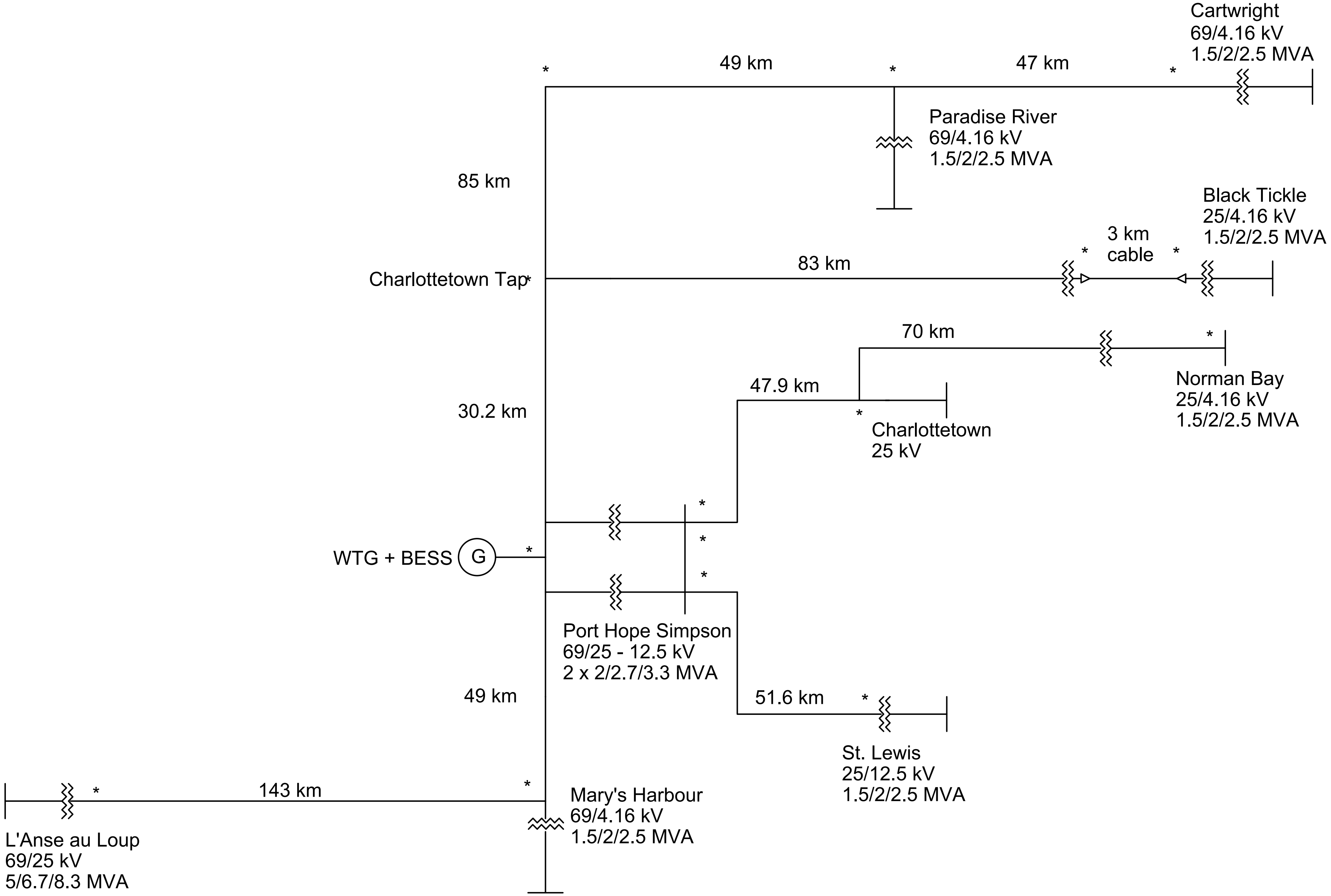
July 30, 2020



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Labrador South Interconnection

Sheet 2 of 2

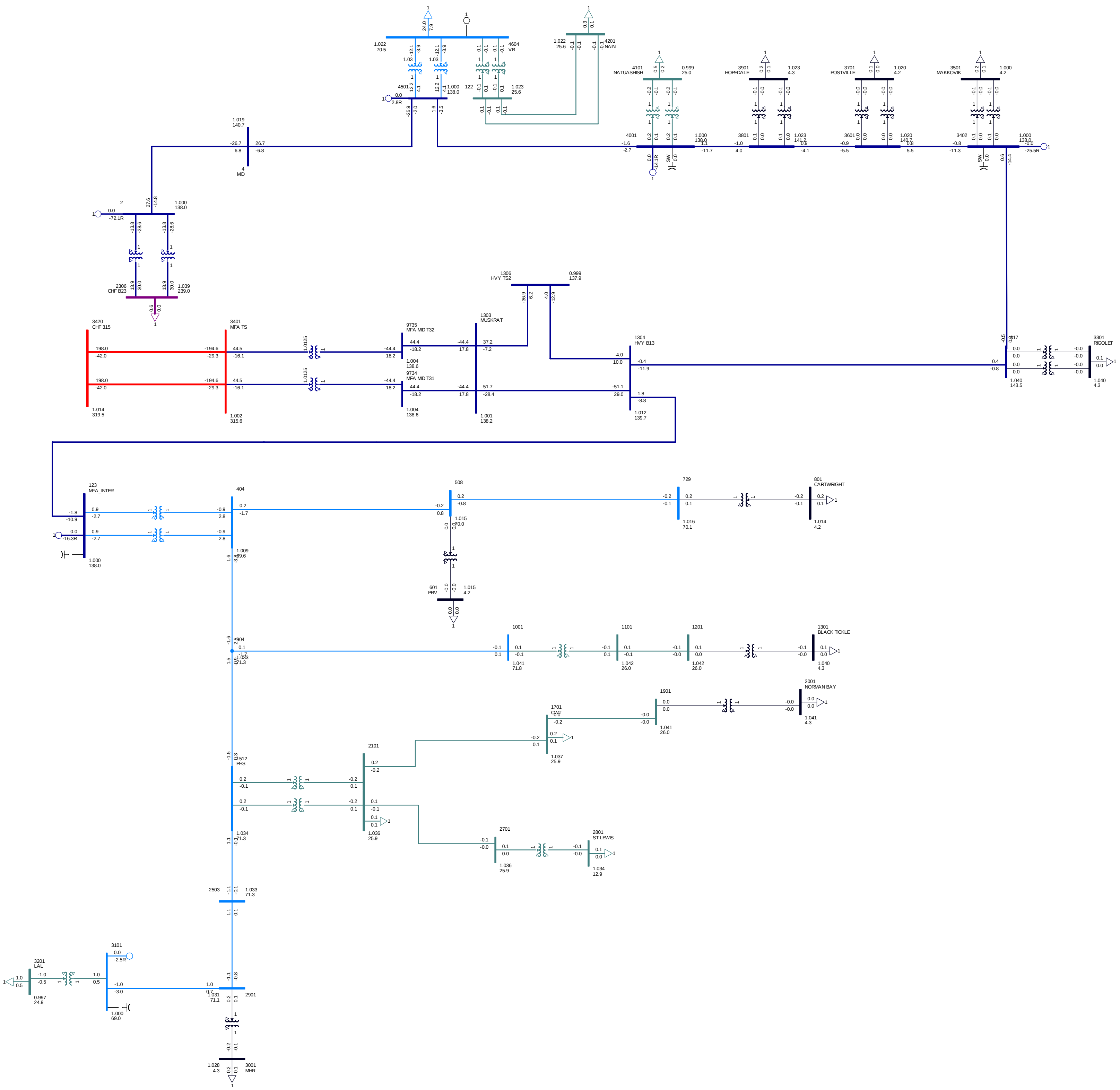
Drawn By: SP

July 30, 2020

Appendix C
Power Flow Study Results

Load Flow Sheets – Option 1

- Sheet 1: Light Load Level
- Sheet 2: Peak Load Level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MFA MID T31
MUSKRAT
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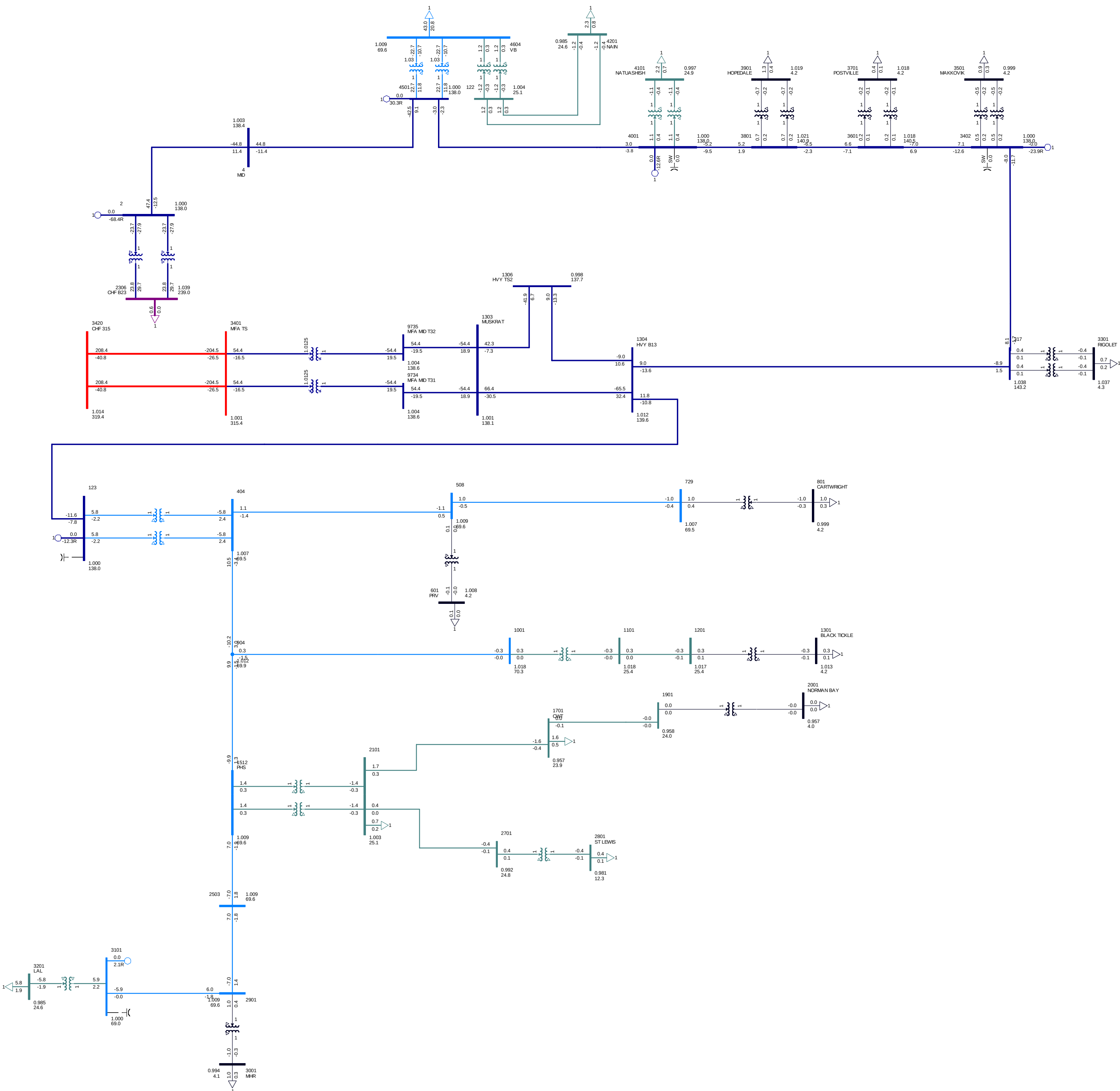
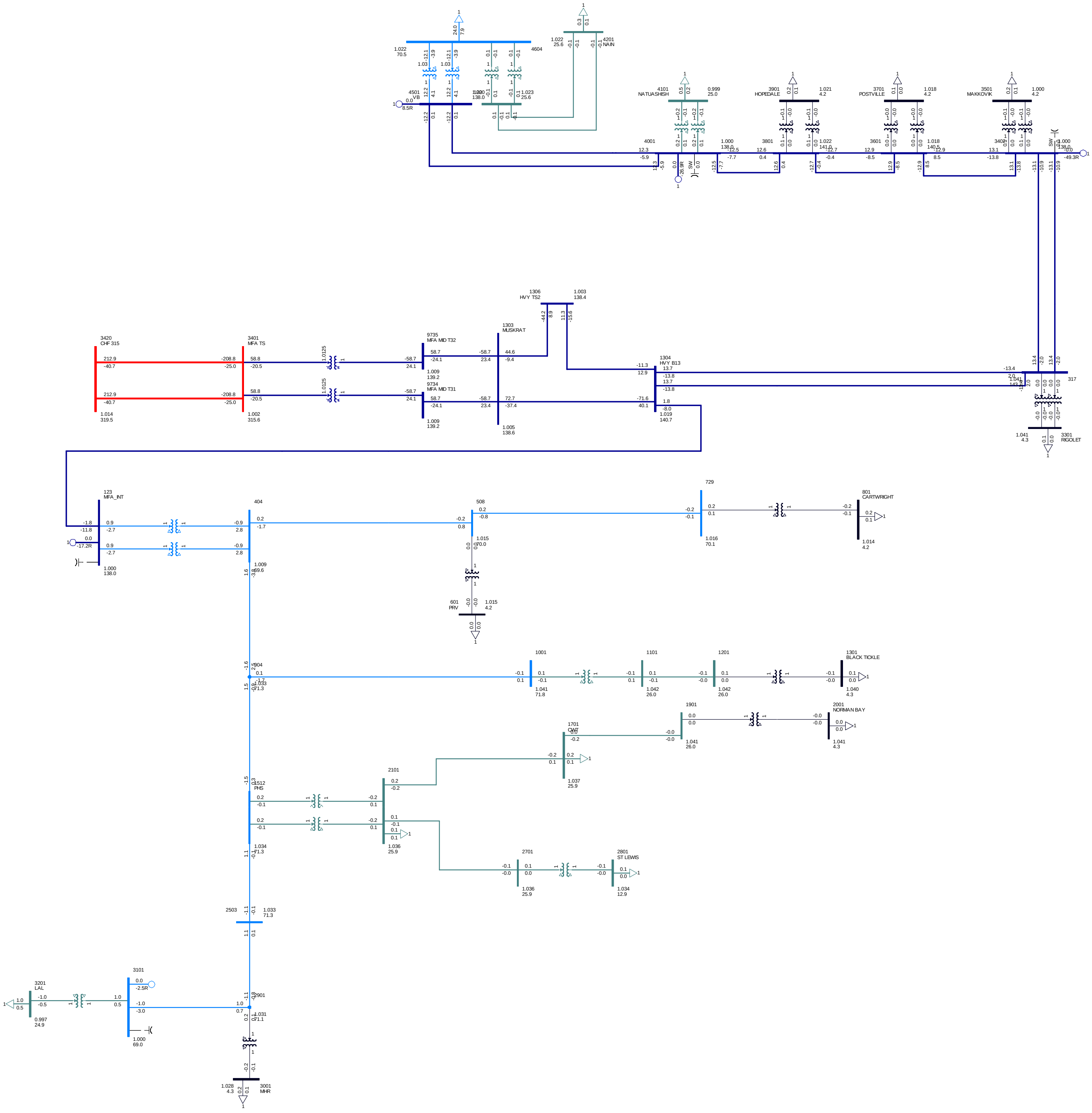
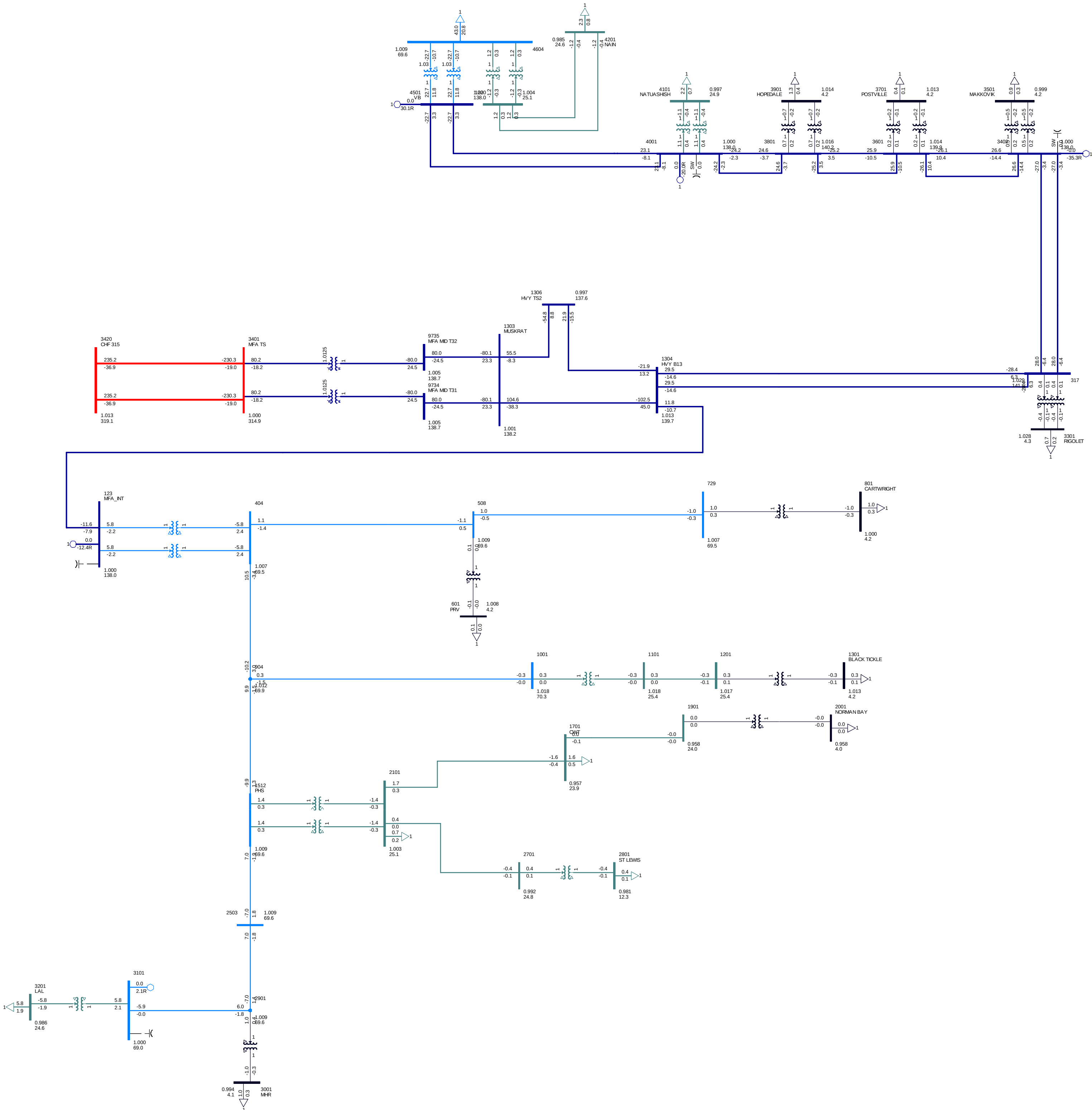
BLACK TICKLE
NORMAN BAY
CHT
PHS
ST LEWIS
LAL
MHR



Load Flow Sheets – Option 2

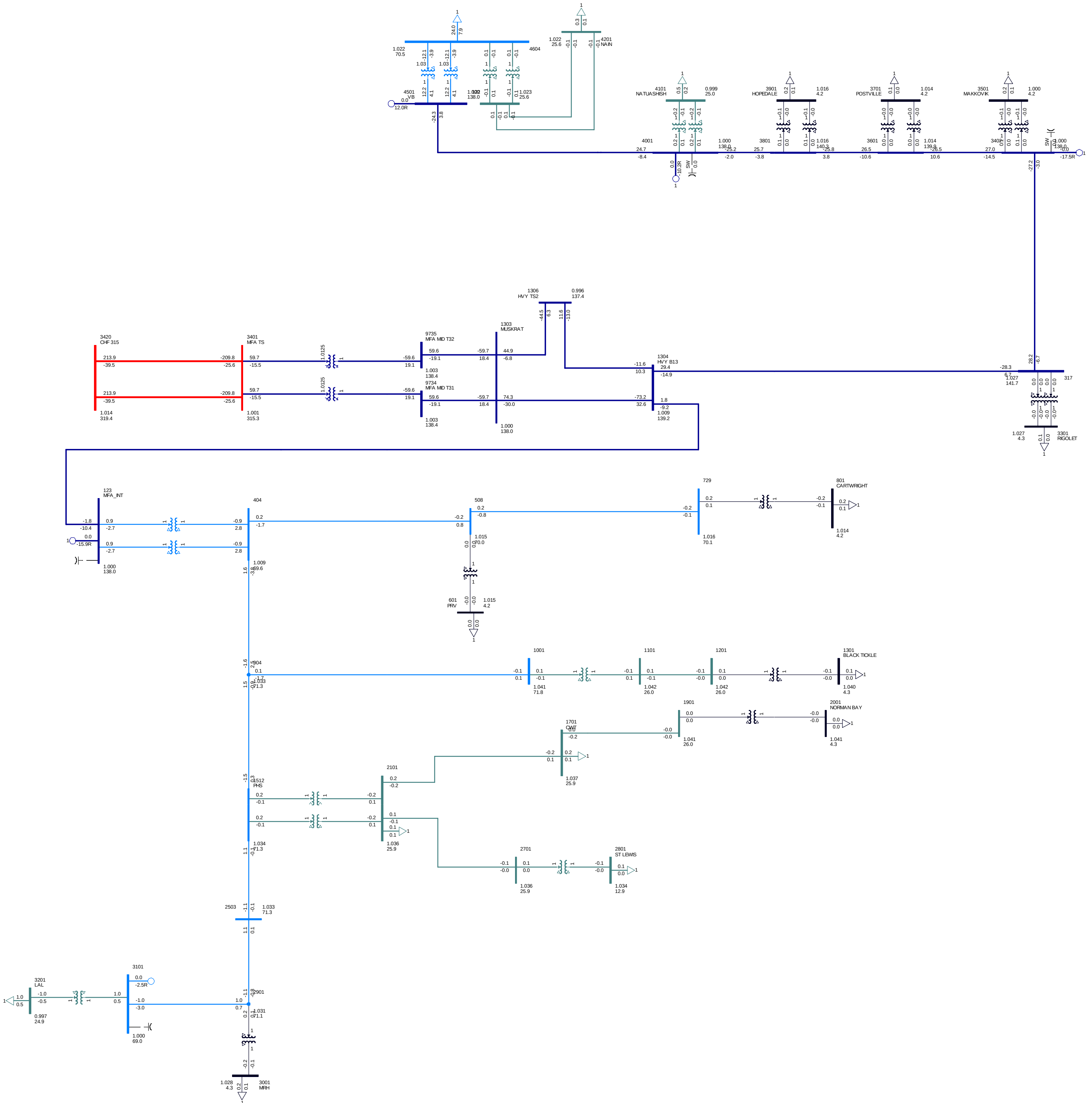
- Sheet 1: Light Load Level
- Sheet 2: Peak Load Level





Load Flow Sheets – Option 3

- Sheet 1: Light Load Level
- Sheet 2: Peak Load Level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MAKKOVIK
3401
1306
HVY TS2
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MUSKRAT
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MFA MID T32
9734
MFA MID T31
3420
CHF 315
3401
MFA TS
1304
HVY B13
317
3301
RIGOLET
123
MFA_INT
404
508
729
801
CARTWRIGHT
601
PRV
1001
1101
1201
1301
BLACK TICKLE
1901
2001
NORMAN BAY
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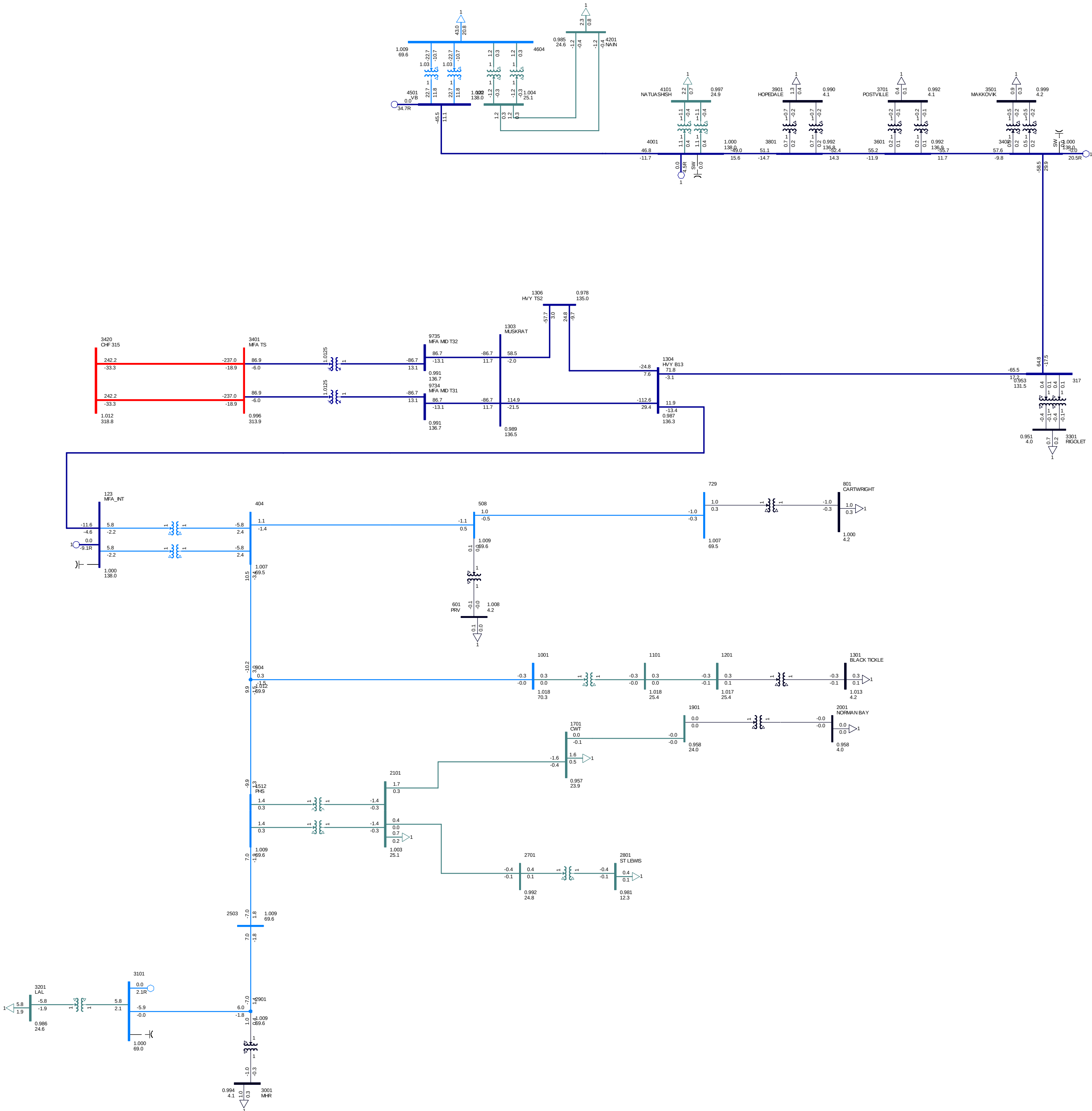
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HVY B13
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3301
RIGOLET
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NORMAN BAY
1701
CWT
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1512
PHS
2701
2801
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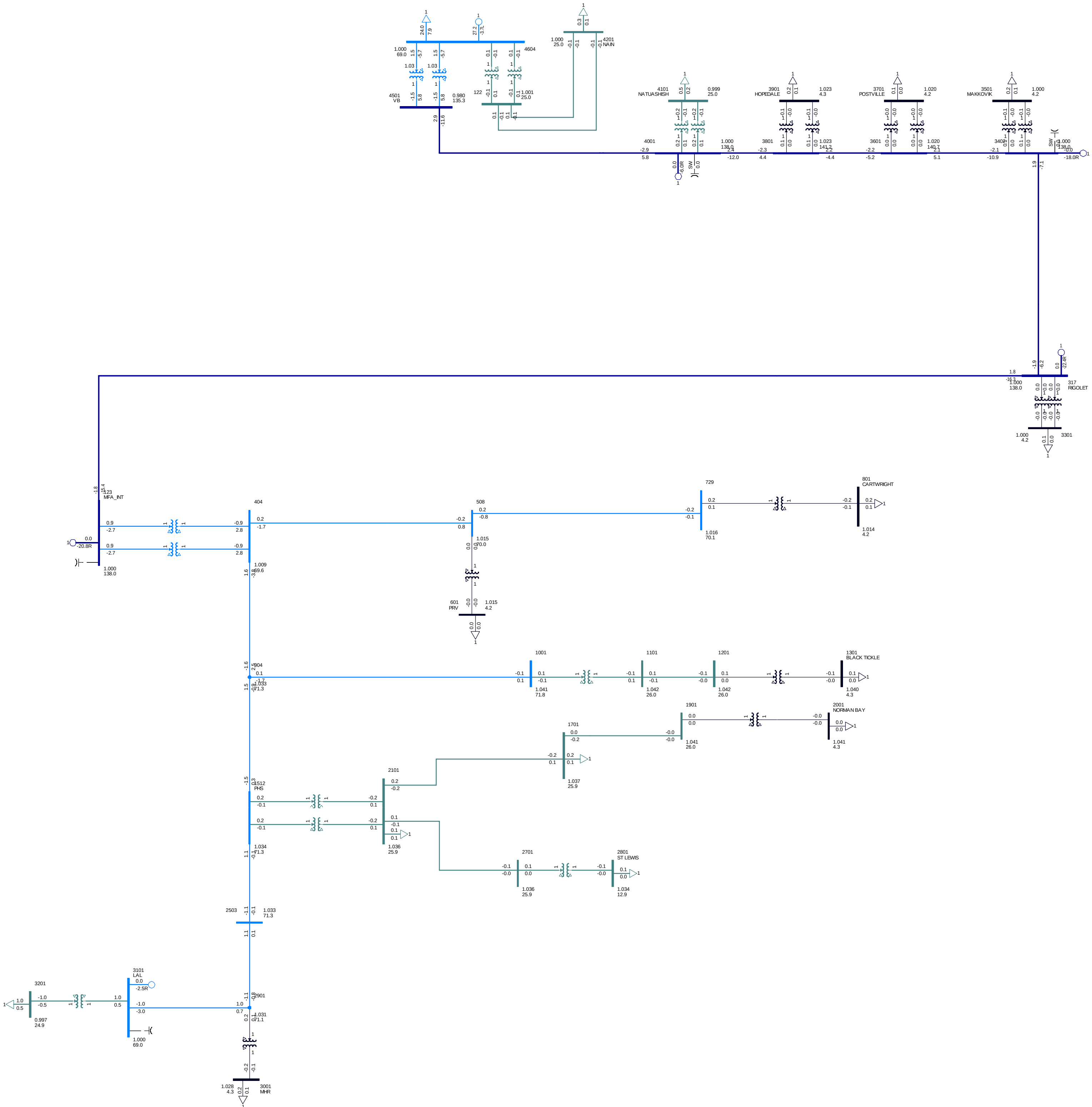
3101
2901
3001
MHR

Load Flow Sheets – Option 4

- Sheet 1: Light Load Level
- Sheet 2: Peak Load Level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317
RIGOLET
3301
123
MFA_INT
404
508
729
801
CARTWRIGHT
601
PRV
1001
1101
1201
1301
BLACK TICKLE
1901
2001
NORMAN BAY
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PHS
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2801
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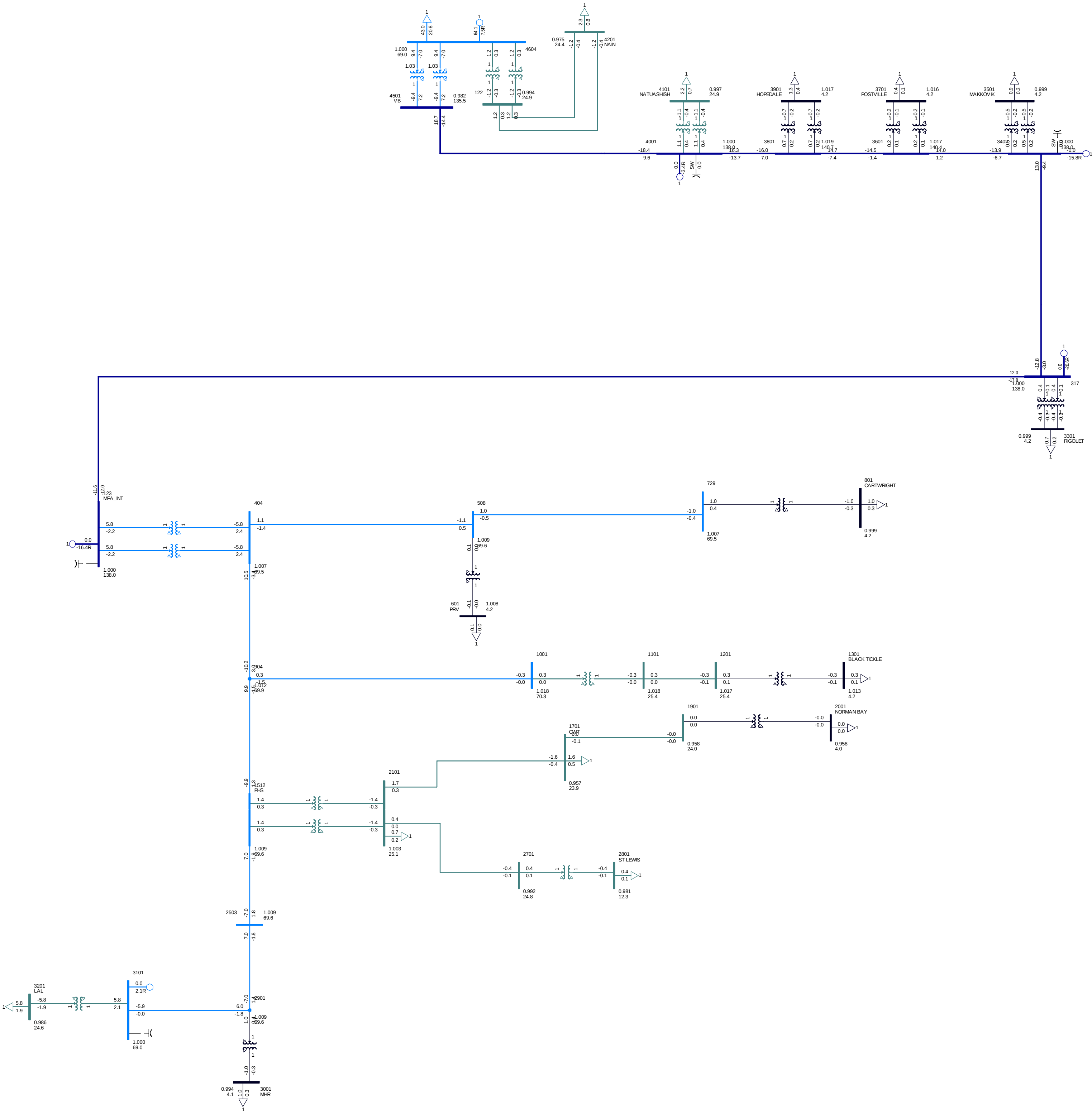
2901
3001
MHR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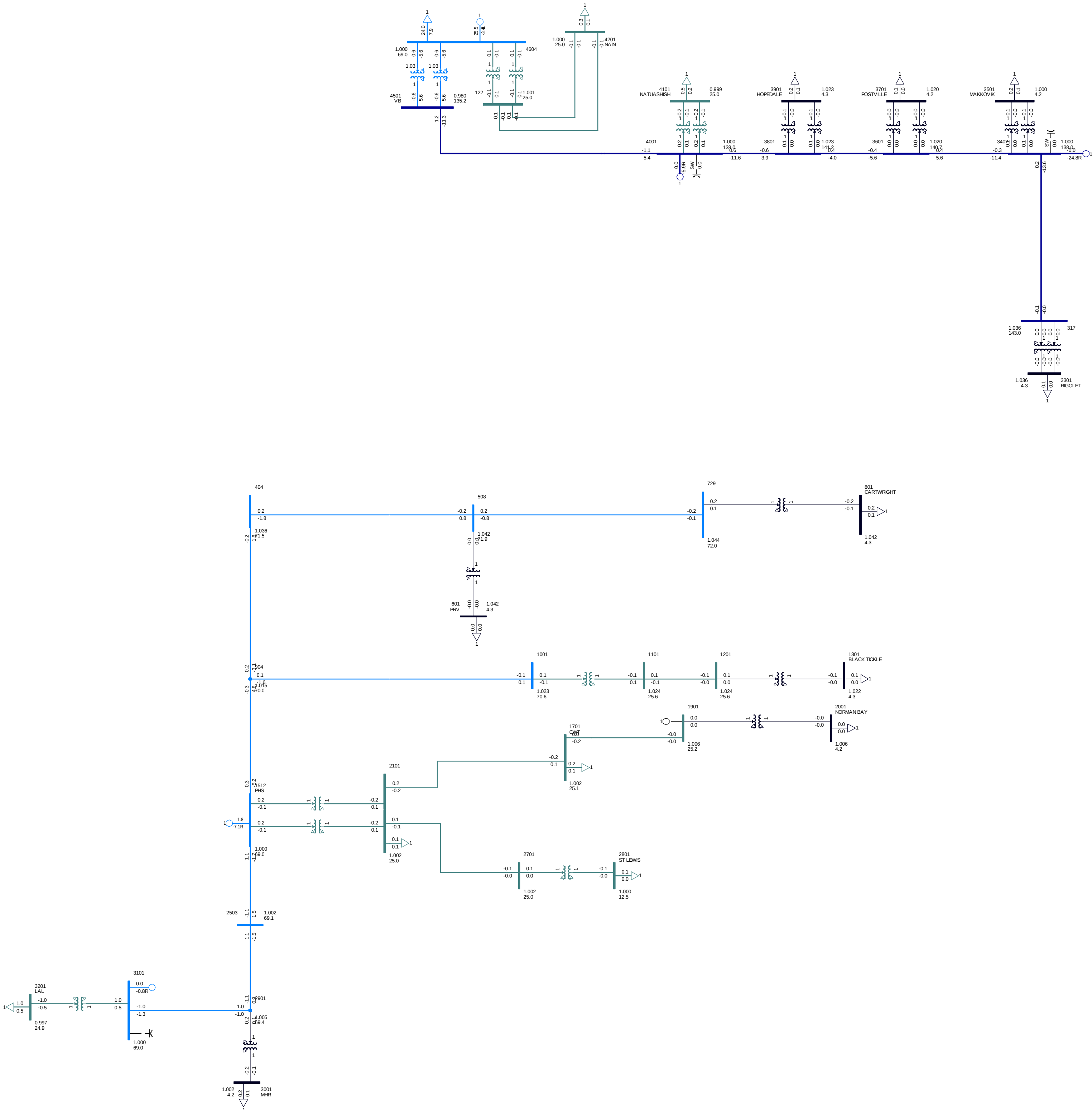
HOPEDALE
POSTVILLE
MAKKOVIK
RIGOLET
MFA_INT
CARTWRIGHT
PRV
BLACK TICKLE
NORMAN BAY
CHT
PHS
ST LEWIS
LAL
MHR

Load Flow Sheets – Option 5

- Sheet 1: Light Load Level
- Sheet 2: Peak Load Level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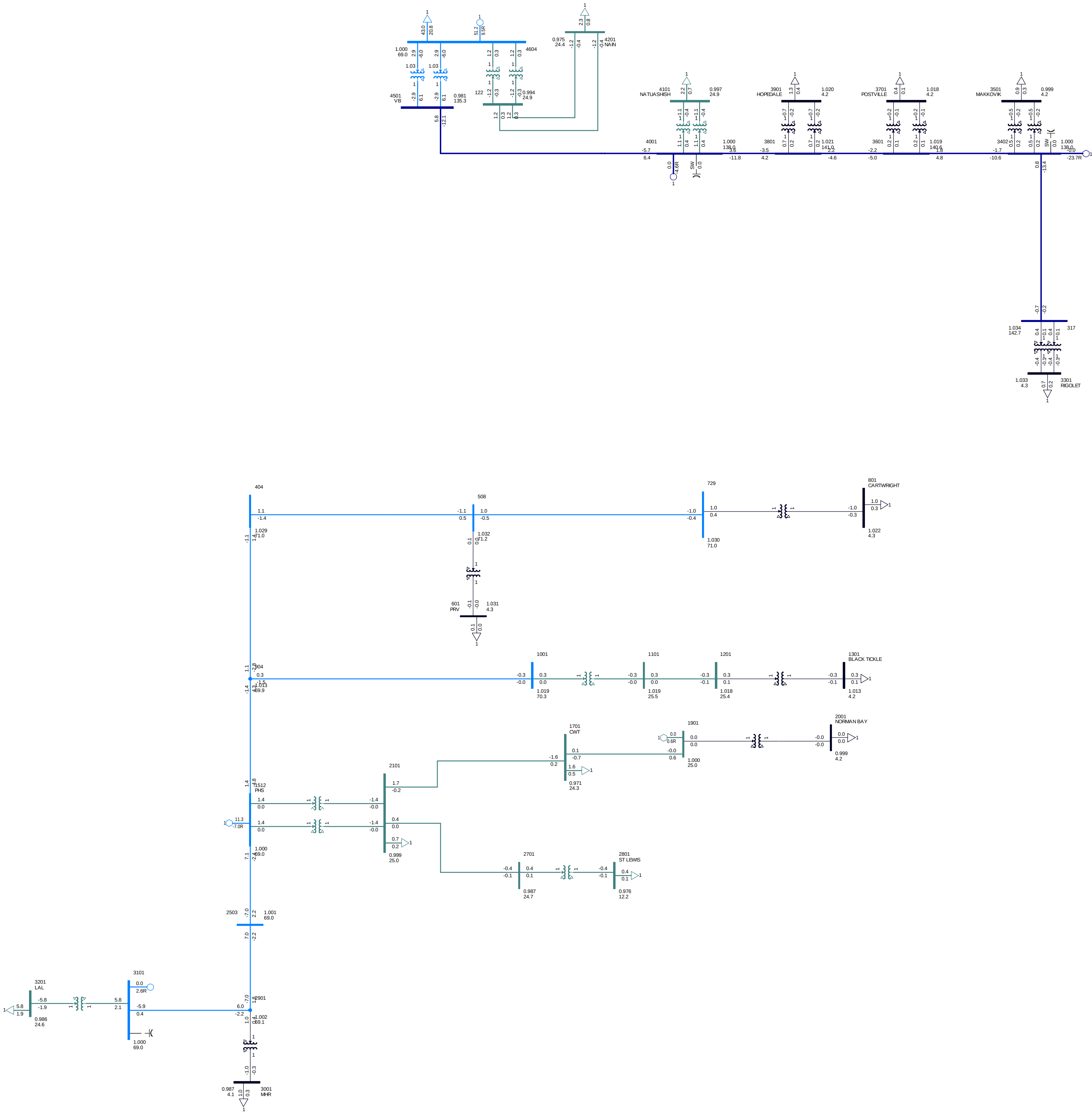
3801
3601
3401
317
3301 RIGOLET
404
508
729
801 CARTWRIGHT
601 PRV
1001
1101
1201
1301 BLACK TICKLE
1901
2001 NORMAN BAY
1701 CHT
2101
1512 PHS
2701
2801 ST LEWIS
2503
3101
3201 LAL
2901
3001 MHR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NATUASHISH
HOPEDALE
POSTVILLE
MAKKOVIK
RIGOLET
CARTWRIGHT
PRV
BLACK TICKLE
CWT
NORMAN BAY
PHS
ST LEWIS
LAL
MHR

Appendix D
Capital Cost Estimate Details

D1. Option 1

D1.1. Northern Loop

Transmission Lines			
Run	**Voltage**	**Distance**	**CAPEX**
Churchill Falls to VB	138 kV	361 km	$306,850,000
VB to Nain - 25 kV line	25 kV	100 km	$23,000,000
VB to Natuashish	138 kV	95 km	$80,750,000
Natuashish to Hopedale	138 kV	118 km	$100,300,000
Hopedale to Postville	138 kV	142 km	$120,700,000
Postville to Makkovik	138 kV	90 km	$76,500,000
Makkovik to Rigolet	138 kV	206 km	$175,100,000
Rigolet to HV Terminal - Muskrat Falls	138 kV	188 km	$159,800,000
Line Tap - 69kV	69 kV		$-
Line Tap - 25kV	25 kV		$-
Reactive Compensation			$5,010,000
TOTAL			$1,048,010,000

Substations		
Community	**Description**	**CAPEX**
Churchill Falls	230 kV to 138 kV; 1 x 37.5/50/62 MVA	$7,500,000
Nain	25 kV to 4.16 kV; 2 x 3.75/5/6 MVA	$4,000,000
Natuashish	138 kV to 25 kV; 2 x 3.75/5/6 MVA transformers	$9,100,000
Hopedale	138 kV to 4.16 kV; 2 x 2/2.7/3.3 MVA transformers	$6,300,000
Postville	138 kV to 4.16 kV; 2 x 1.5/2/2.5 MVA transformers	$5,900,000

Makkovik	138 kV to 4.16 kV 2 x 1.5/2/2.5 MVA transformers	$5,900,000
Rigolet	138 kV to 4.16 kV 2 x 1.5/2/2.5 MVA transformers	$5,900,000
TOTAL		$44,600,000

*assumes VB responsible for their own substation

D1.2. Southern Loop

Transmission Lines			
Run	**Voltage**	**Distance / Units**	**CAPEX**
HV-GB To Muskrat Falls Intersection	138 kV	300 km	$204,000,000
Muskrat Falls Intersection to Paradise River	69 kV	49 km	$14,210,000
Paradise River to Cartwright	69 kV	47 km	$13,630,000
Muskrat Falls Intersection to Charlottetown Tap	69 kV	85 km	$49,300,000
Charlottetown Tap to Black Tickle, last 3 km are underwater	69 kV	83 km	$24,070,000
	25 kV	3 km	$10,500,000
Charlottetown Tap to Port Hope Simpson	69 kV	30 km	$17,516,000
Port Hope Simpson to Charlottetown	25 kV	48 km	$9,101,000
Charlottetown to Norman Bay	25 kV	70 km	$13,300,000
Port Hope Simpson to St. Lewis	25 kV	52 km	$9,804,000
Port Hope Simpson to Mary's Harbour	69 kV	49 km	$28,420,000
Mary's Harbour to L'Anse-au-Loop	69 kV	143 km	$82,940,000
Line Tap - 69kV	69 kV	3	$7,500,000
Line Tap - 25kV	25 kV	1	$1,700,000
Reactive Compensation		As per D1.3	$1,181,000
TOTAL			$487,172,000

Substations		
Community	**Description**	**CAPEX**
Muskrat Falls Intersection	138 kV to 69 kV; 2 x 10/13.3/16.6 MVA	$9,800,000
Paradise River	69 kV to 4.16 kV; 1 x 1.5/2/2.5 MVA	$3,700,000
Cartwright	69 kV to 4.16 kV; 1 x 1.5/2/2.5 MVA	$3,700,000
Black Tickle	69 kV to 25 kV; 1 x 1.5/2/2.5 MVA	$6,100,000
	25 kV to 4.16 kV; 1 x 1.5/2/2.5 MVA	$2,400,000
Port Hope Simpson	69 kV to 25 kV - 12.5 kV; 2 x 2/2.7/3.3 MVA	$7,400,000
Charlottetown*	25 kV to 4.16 kV; 1 x 2/2.7/3.3 MVA	$2,800,000
Norman Bay*	25 kV to 4.16 kV; 1 x 1.5/2/2.5 MVA	$2,400,000
St. Lewis	25 kV to 12.5 kV; 1 x 1.5/2/2.5 MVA	$3,400,000
Mary's Harbour	69 kV to 4.16 kV; 1 x 1.5/2/2.5 MVA	$3,700,000
L'Anse-Au-Loop	69 kV to 25 kV; 1 x 5/6.7/8.3 MVA	$6,700,000
Mobile Substation	x1	$5,500,000
TOTAL		$57,600,000

*NL Hydro exploring conversion of NB and CT to 25 kV, currently 4.16 kV

D1.3. Reactive Compensation

Bus No.	Bus Name (SLD)	Pre - Contingency	Post – Contingency	Technology	Inductive Capacity (Mvar)	Capacitive Capacity (Mvar)	Total Cost
2	CHF 138 kV	-73 Mvar	-73 Mvar	Line Reactors	73	0	$1,679,000
123	Muskrat 138 kV	-17 Mvar	-16 Mvar	Line Reactors	17	0	$391,000
3101	LAL 69 kV	-3/+2 Mvar	-3/+2 Mvar	D-Statcom	3	2	$1,181,000
3402	Makkovik 138	-26 Mvar	-25/20 Mvar	Switched L/C	26	20	$1,258,000

Bus No.	Bus Name (SLD)	Pre - Contingency	Post – Contingency	Technology	Inductive Capacity (Mvar)	Capacitive Capacity (Mvar)	Total Cost
	kV						
4001	Natuashish 138 kV	-15 Mvar	-15/+5 Mvar	Switched L/C	15	5	$750,000
4501*	VB 138 kV	+31 Mvar	+36 Mvar	Switched Capacitor	0	36	$932,000
TOTAL							$6,191,000

*Assumes no generation connected at VB

D2. Option 2

D2.1. Northern Loop

Transmission Lines			
Run	**Voltage**	**Distance**	**CAPEX**
VB to Nain - 25 kV line	25 kV	100 km	$23,000,000
VB to Natuashish	138 kV	190 km	$161,500,000
Natuashish to Hopedale	138 kV	236 km	$200,600,000
Hopedale to Postville	138 kV	284 km	$241,400,000
Postville to Makkovik	138 kV	180 km	$153,000,000
Makkovik to Rigolet	138 kV	412 km	$350,200,000
Rigolet to HV Terminal - Muskrat Falls	138 kV	376 km	$319,600,000
Line Tap - 69kV	69 kV		$-
Line Tap - 25kV	25 kV		$-
Reactive Compensation		As per D2.3	$5,215,000
TOTAL			$1,454,515,000

Substations		
Community	**Description**	**CAPEX**
Nain	25 kV to 4.16 kV; 2 x 3.75/5/6 MVA	$4,000,000
Natuashish	138 kV to 25 kV; 2 x 3.75/5/6 MVA transformers	$9,100,000
Hopedale	138 kV to 4.16 kV; 2 x 2/2.7/3.3 MVA transformers	$6,300,000
Postville	138 kV to 4.16 kV; 2 x 1.5/2/2.5 MVA transformers	$5,900,000
Makkovik	138 kV to 4.16 kV 2 x 1.5/2/2.5 MVA transformers	$5,900,000
Rigolet	138 kV to 4.16 kV 2 x 1.5/2/2.5 MVA transformers	$5,900,000
TOTAL		$37,100,000

D2.2. Southern Loop

Transmission Lines			
Run	**Voltage**	**Distance / Units**	**CAPEX**
HV-GB To Muskrat Falls Intersection	138 kV	300 km	$204,000,000
Muskrat Falls Intersection to Paradise River	69 kV	49 km	$14,210,000
Paradise River to Cartwright	69 kV	47 km	$13,630,000
Muskrat Falls Intersection to Charlottetown Tap	69 kV	85 km	$49,300,000
Charlottetown Tap to Black Tickle, last 3 km are underwater	69 kV	83 km	$24,070,000
	25 kV	3 km	$10,500,000
Charlottetown Tap to Port Hope Simpson	69 kV	30 km	$17,516,000
Port Hope Simpson to Charlottetown	25 kV	48 km	$9,101,000
Charlottetown to Norman Bay	25 kV	70 km	$13,300,000
Port Hope Simpson to St. Lewis	25 kV	52 km	$9,804,000
Port Hope Simpson to Mary's Harbour	69 kV	49 km	$28,420,000
Mary's Harbour to L'Anse-au-Loop	69 kV	143 km	$82,940,000
Line Tap - 69kV	69 kV	3	$7,500,000
Line Tap - 25kV	25 kV	1	$1,700,000
Reactive Compensation		As per D2.3	$1,395,000
TOTAL			$487,386,000

Substations		
Community	**Description**	**CAPEX**
Muskrat Falls Intersection	138 kV to 69 kV; 2 x 10/13.3/16.6 MVA	$9,800,000
Paradise River	69 kV to 4.16 kV; 1 x 1.5/2/2.5 MVA	$3,700,000
Cartwright	69 kV to 4.16 kV; 1 x 1.5/2/2.5 MVA	$3,700,000
Black Tickle	69 kV to 25 kV; 1 x 1.5/2/2.5 MVA	$6,100,000
	25 kV to 4.16 kV; 1 x 1.5/2/2.5 MVA	$2,400,000

Port Hope Simpson	69 kV to 25 kV - 12.5 kV; 2 x 2/2.7/3.3 MVA	$7,400,000
Charlottetown*	25 kV to 4.16 kV; 1 x 2/2.7/3.3 MVA	$2,800,000
Norman Bay*	25 kV to 4.16 kV; 1 x 1.5/2/2.5 MVA	$2,400,000
St. Lewis	25 kV to 12.5 kV; 1 x 1.5/2/2.5 MVA	$3,400,000
Mary's Harbour	69 kV to 4.16 kV; 1 x 1.5/2/2.5 MVA	$3,700,000
L'Anse-Au-Loop	69 kV to 25 kV; 1 x 5/6.7/8.3 MVA	$6,700,000
Mobile Substation	x1	$5,500,000
TOTAL		$57,600,000

*NL Hydro exploring conversion of NB and CT to 25 kV, currently 4.16 kV

D2.3. Reactive Compensation

Bus No.	Bus Name (SLD)	Pre – Contingency	Technology	Post-Contingency	Inductive Capacity (Mvar)	Capacitive Capacity (Mvar)	Total Cost
123	Muskrat 138 kV	-18 Mvar	Line Reactors	-19 Mvar	73	0	$1,679,000
3101	LAL 69 kV	-3/+3 Mvar	D-Statcom	-3/+3 Mvar	3	3	$1,395,000
3402	Makkovik 138 kV	-50 Mvar	Line Reactors	-46 Mvar	50	0	$1,150,000
4001	Natuashish 138 kV	-27 Mvar	Line Reactors	-53 Mvar	53	0	$1,539,000
4501*	VB 138 kV	+31 Mvar	Switched Capacitor	+30 Mvar	0	31	$847,000
TOTAL							$6,610,000

*Assumes no generation connected at VB

D3. Option 3

D3.1. Northern Loop

Transmission Lines			
Run	**Voltage**	**Distance / Units**	**CAPEX**
VB to Nain - 25 kV line	25 kV	100 km	$23,000,000
VB to Natuashish	138 kV	95 km	$80,750,000
Natuashish to Hopedale	138 kV	118 km	$100,300,000
Hopedale to Postville	138 kV	142 km	$120,700,000
Postville to Makkovik	138 kV	90 km	$76,500,000
Makkovik to Rigolet	138 kV	206 km	$175,100,000
Rigolet to HV Terminal - Muskrat Falls	138 kV	188 km	$159,800,000
Line Tap - 69kV	69 kV		$-
Line Tap - 25kV	25 kV		$-
Reactive Compensation		As per D3.3	$3,032,000
TOTAL			$739,182,000

Substations		
Community	**Description**	**CAPEX**
Nain	25 kV to 4.16 kV; 2 x 3.75/5/6 MVA	$4,000,000
Natuashish	138 kV to 25 kV; 2 x 3.75/5/6 MVA transformers	$9,100,000
Hopedale	138 kV to 4.16 kV; 2 x 2/2.7/3.3 MVA transformers	$6,300,000
Postville	138 kV to 4.16 kV; 2 x 1.5/2/2.5 MVA transformers	$5,900,000
Makkovik	138 kV to 4.16 kV 2 x 1.5/2/2.5 MVA transformers	$5,900,000
Rigolet	138 kV to 4.16 kV 2 x 1.5/2/2.5 MVA transformers	$5,900,000
TOTAL		$37,100,000

*assume VB responsible for their own substation

D3.2. Southern Loop

Transmission Lines			
Run	**Voltage**	**Distance / Units**	**CAPEX**
HV-GB To Muskrat Falls Intersection	138 kV	300 km	$204,000,000
Muskrat Falls Intersection to Paradise River	69 kV	49 km	$14,210,000
Paradise River to Cartwright	69 kV	47 km	$13,630,000
Muskrat Falls Intersection to Charlottetown Tap	69 kV	85 km	$49,300,000
Charlottetown Tap to Black Tickle, last 3 km are underwater	69 kV	83 km	$24,070,000
	25 kV	3 km	$10,500,000
Charlottetown Tap to Port Hope Simpson	69 kV	30 km	$17,516,000
Port Hope Simpson to Charlottetown	25 kV	48 km	$9,101,000
Charlottetown to Norman Bay	25 kV	70 km	$13,300,000
Port Hope Simpson to St. Lewis	25 kV	52 km	$9,804,000
Port Hope Simpson to Mary's Harbour	69 kV	49 km	$28,420,000
Mary's Harbour to L'Anse-au-Loop	69 kV	143 km	$82,940,000
Line Tap - 69kV	69 kV	3	$7,500,000
Line Tap - 25kV	25 kV	1	$1,700,000
Reactive Compensation		As per D3.3	$1,284,000
TOTAL			$487,275,000

Substations		
Community	**Description**	**CAPEX**
Muskrat Falls Intersection	138 kV to 69 kV; 2 x 10/13.3/16.6 MVA	$9,800,000
Paradise River	69 kV to 4.16 kV; 1 x 1.5/2/2.5 MVA	$3,700,000
Cartwright	69 kV to 4.16 kV; 1 x 1.5/2/2.5 MVA	$3,700,000
Black Tickle	69 kV to 25 kV; 1 x 1.5/2/2.5 MVA	$6,100,000
	25 kV to 4.16 kV; 1 x 1.5/2/2.5 MVA	$2,400,000

Port Hope Simpson	69 kV to 25 kV - 12.5 kV; 2 x 2/2.7/3.3 MVA	$7,400,000
Charlottetown*	25 kV to 4.16 kV; 1 x 2/2.7/3.3 MVA	$2,800,000
Norman Bay*	25 kV to 4.16 kV; 1 x 1.5/2/2.5 MVA	$2,400,000
St. Lewis	25 kV to 12.5 kV; 1 x 1.5/2/2.5 MVA	$3,400,000
Mary's Harbour	69 kV to 4.16 kV; 1 x 1.5/2/2.5 MVA	$3,700,000
L'Anse-Au-Loop	69 kV to 25 kV; 1 x 5/6.7/8.3 MVA	$6,700,000
Mobile Substation	x1	$5,500,000
TOTAL		$57,600,000

*NL Hydro exploring conversion of NB and CT to 25 kV, currently 4.16 kV

D3.3. Reactive Compensation

Bus No.	Bus Name (SLD)	Pre – Contingency	Technology	Inductive Capacity (Mvar)	Capacitive Capacity (Mvar)	Total Cost
123	Muskrat 138 kV	-16 Mvar	Line Reactors	16	0	$368,000
3101	LAL 69 kV	-3/+3 Mvar	D-Statcom	3	3	$1,284,000
3402	Makkovik 138 kV	-18/+21 Mvar	Switched L/C	18	21	$1,091,000
4001	Natuashish 138 kV	-11/+5 Mvar	Switched L/C	11	5	$658,000
4501*	VB 138 kV	+35 Mvar	Switched Capacitor	0	35	$915,000
TOTAL						$4,316,000

*Assumes no generation connected at VB

D4. Option 4

D4.1. Northern Loop

Transmission Lines			
Run	**Voltage**	**Distance / Units**	**CAPEX**
VB to Nain - 25 kV line	25 kV	100 km	$23,000,000
VB to Natuashish	138 kV	95 km	$80,750,000
Natuashish to Hopedale	138 kV	118 km	$100,300,000
Hopedale to Postville	138 kV	142 km	$120,700,000
Postville to Makkovik	138 kV	90 km	$76,500,000
Makkovik to Rigolet	138 kV	206 km	$175,100,000
Rigolet to HV Terminal - Muskrat Falls	138 kV	188 km	$159,800,000
Line Tap - 69kV	69 kV		$-
Line Tap - 25kV	25 kV		$-
Reactive Compensation		As per D4.3	$2,687,000
TOTAL			$738,837,000

Substations		
Community	**Description**	**CAPEX**
Nain	25 kV to 4.16 kV; 2 x 3.75/5/6 MVA	$4,000,000
Natuashish	138 kV to 25 kV; 2 x 3.75/5/6 MVA transformers	$9,100,000
Hopedale	138 kV to 4.16 kV; 2 x 2/2.7/3.3 MVA transformers	$6,300,000
Postville	138 kV to 4.16 kV; 2 x 1.5/2/2.5 MVA transformers	$5,900,000
Makkovik	138 kV to 4.16 kV 2 x 1.5/2/2.5 MVA transformers	$5,900,000
Rigolet	138 kV to 4.16 kV 2 x 1.5/2/2.5 MVA transformers	$5,900,000
TOTAL		$37,100,000

Generation		
Community	**Wind**	**CAPEX**
Voisey's Bay	11 x 3.5 MW	$135,150,000

D4.2. Southern Loop

Transmission Lines			
Run	**Voltage**	**Distance**	**CAPEX**
HV to Muskrat Intersection	138 kV	300 km	$204,000,000
Paradise River to Junction	69 kV	49 km	$14,210,000
Paradise River to Cartwright	69 kV	47 km	$13,630,000
Junction to Charlottetown Tap	69 kV	85 km	$49,300,000
Charlottetown Tap to Black Tickle, last 3 km are underwater	69 kV	83 km	$24,070,000
	25 kV	3 km	$10,500,000
Charlottetown Tap to Port Hope Simpson	69 kV	30 km	$17,516,000
Port Hope Simpson to Charlottetown	25 kV	48 km	$9,101,000
Charlottetown to Norman Bay	25 kV	70 km	$13,300,000
Port Hope Simpson to St. Lewis	25 kV	52 km	$9,804,000
Port Hope Simpson to Mary's Harbour	69 kV	49 km	$28,420,000
Mary's Harbour to L'Anse-au-Loop	69 kV	143 km	$82,940,000
Line Tap - 69kV	69 kV	3	$7,500,000
Line Tap - 25kV	25 kV	1	$1,700,000
Reactive Compensation			$1,181,000
TOTAL			$487,172,000

Substations

Community	Description	CAPEX
Junction	138 kV to 69 kV; 2 x 10/13.3/16.6 MVA	$9,800,000
Paradise River	69 kV to 4.16 kV; 1 x 1.5/2/2.5 MVA	$3,700,000
Cartwright	69 kV to 4.16 kV; 1 x 1.5/2/2.5 MVA	$3,700,000
Black Tickle	69 kV to 25 kV; 1 x 1.5/2/2.5 MVA	$6,100,000
	25 kV to 4.16 kV; 1 x 1.5/2/2.5 MVA	$2,400,000
Port Hope Simpson	69 kV to 25 kV - 12.5 kV; 2 x 2/2.7/3.3 MVA	$7,400,000
Charlottetown*	25 kV to 4.16 kV; 1 x 2/2.7/3.3 MVA	$2,800,000
Norman Bay*	25 kV to 4.16 kV; 1 x 1.5/2/2.5 MVA	$2,400,000
St. Lewis	25 kV to 12.5 kV; 1 x 1.5/2/2.5 MVA	$3,400,000
Mary's Harbour	69 kV to 4.16 kV; 1 x 1.5/2/2.5 MVA	$3,700,000
L'Anse-Au-Loop	69 kV to 25 kV; 1 x 5/6.7/8.3 MVA	$6,700,000
Mobile Substation	x1	$5,500,000
TOTAL		$57,600,000

D4.3. Reactive Compensation

Bus No.	Bus Name (SLD)	Pre - Con	Post – Con	Technology	Inductive Capacity (Mvar)	Capacitive Capacity (Mvar)	Total Cost
123	Muskrat 138 kV	- 21 Mvar	- 21 Mvar	Line Reactors	21	0	$483,000
317	Rigolet 138 kV	-23 Mvar	-35 Mvar	Line Reactor	35	0	$805,000
3101	LAL 69 kV	- 3/+2 Mvar	- 3/+2 Mvar	D-Statcom	3	2	$1,181,000
3402	Makkovik 138 kV	-18 Mvar	-21 Mvar	Line Reactors	20	0	$780,000
4001	Natuashish 138 kV	- 6 Mvar	- 13 Mvar	Line Reactors	13	0	$619,000
TOTAL							$3,868,000

D5. Option 5

D5.1. Northern Loop

Transmission Lines			
Run	**Voltage**	**Distance / Units**	**CAPEX**
VB to Nain - 25 kV line	25 kV	100 km	$23,000,000
VB to Natuashish	138 kV	95 km	$80,750,000
Natuashish to Hopedale	138 kV	118 km	$100,300,000
Hopedale to Postville	138 kV	142 km	$120,700,000
Postville to Makkovik	138 kV	90 km	$76,500,000
Makkovik to Rigolet	138 kV	206 km	$175,100,000
Reactive Compensation		As per D.5.3	$759,000
TOTAL			$577,109,000

Substations		
Community	**Description**	**CAPEX**
Nain	25 kV to 4.16 kV; 2 x 3.75/5/6 MVA	$4,000,000
Natuashish	138 kV to 25 kV; 2 x 3.75/5/6 MVA transformers	$9,100,000
Hopedale	138 kV to 4.16 kV; 2 x 2/2.7/3.3 MVA transformers	$6,300,000
Postville	138 kV to 4.16 kV; 2 x 1.5/2/2.5 MVA transformers	$5,900,000
Makkovik	138 kV to 4.16 kV 2 x 1.5/2/2.5 MVA transformers	$5,900,000
Rigolet	138 kV to 4.16 kV 2 x 1.5/2/2.5 MVA transformers	$5,900,000
TOTAL		$37,100,000

*assume VB responsible for their own substation

Generation		
Community	**Wind**	**CAPEX**
Voisey's Bay	5 x 3.5 MW	$61,650,000

D5.2. Southern Loop

Transmission Lines			
Run	**Voltage**	**Distance / Units**	**CAPEX**
Paradise River to Junction	69 kV	49 km	$14,210,000
Paradise River to Cartwright	69 kV	47 km	$13,630,000
Junction to Charlottetown Tap	69 kV	85 km	$49,300,000
Charlottetown Tap to Black Tickle - underwater cable for last 3 km	69 kV	83 km	$24,070,000
	25 kV	3 km	$10,500,000
Charlottetown Tap to Port Hope Simpson	69 kV	30 km	$17,516,000
Port Hope Simpson to Charlottetown	25 kV	48 km	$9,101,000
Charlottetown to Norman Bay	25 kV	70 km	$13,300,000
Port Hope Simpson to St. Lewis	25 kV	52 km	$9,804,000
Port Hope Simpson to Mary's Harbour	69 kV	49 km	$28,420,000
Mary's Harbour to L'Anse-au-Loop	69 kV	143 km	$82,940,000
Line Tap - 69kV	69 kV	3	$7,500,000
Line Tap - 25kV	25 kV	1	$1,700,000
Reactive Compensation		As per D5.3	$1,204,500
TOTAL			$283,195,500

Substations		
Community	**Description**	**CAPEX**
Paradise River	69 kV to 4.16 kV; 1 x 1.5/2/2.5 MVA	$3,700,000
Cartwright	69 kV to 4.16 kV; 1 x 1.5/2/2.5 MVA	$3,700,000
Black Tickle	69 kV to 25 kV; 1 x 1.5/2/2.5 MVA	$6,100,000
	25 kV to 4.16 kV; 1 x 1.5/2/2.5 MVA	$2,400,000
Port Hope Simpson	69 kV to 25 kV - 12.5 kV; 2 x 2/2.7/3.3 MVA	$7,400,000

Charlottetown*	25 kV to 4.16 kV; 1 x 2/2.7/3.3 MVA	$2,800,000
Norman Bay*	25 kV to 4.16 kV; 1 x 1.5/2/2.5 MVA	$2,400,000
St. Lewis	25 kV to 12.5 kV; 1 x 1.5/2/2.5 MVA	$3,400,000
Mary's Harbour	69 kV to 4.16 kV; 1 x 1.5/2/2.5 MVA	$3,700,000
L'Anse-Au-Loop	69 kV to 25 kV; 1 x 5/6.7/8.3 MVA	$6,700,000
Mobile Substation	x1	$5,500,000
TOTAL		$47,800,000

*NL Hydro exploring conversion of NB and CT to 25 kV, currently 4.16 kV

Generation			
Community	**Wind**	**BESS**	**CAPEX**
Cartwright or Port Hope Simpson	6 x 3.5 MW	3.5 MW/1.75 MWh	$77,200,000

D5.3. Reactive Compensation

Bus No.	Bus Name (SLD)	Pre – Contingency	Post – Contingency	Technology	Inductive Capacity	Capacitive Capacity	Total Cost
1512	PHS	- 7 Mvar	- 7 Mvar	Line Reactors	7	0	$161,000
1901	Norman Bay (NOB)	+1 Mvar	+1 Mvar	Capacitor	0	1	$76,500
3101	LAL 69 kV	+3/-1 Mvar	+3/-1 Mvar	D-Statcom	1	3	$967,000
3402	Makkovik 138 kV	-20 Mvar	N/A	Line Reactors	20	0	$460,000
4001	Natuashish 138 kV	- 6 Mvar	- 8 Mvar	Line Reactors	8	0	$184,000
?	MAK to POV	-5MVAr	-5MVAr	Line Reactors	5	0	$115,000
TOTAL							$1,963,500

D6. Option 6

D6.1. Northern Loop

Generation			
Community	**Wind**	**BESS**	**CAPEX**
Nain	1 x 3.5 MW	2.5 MW/1.25 MWh	$20,660,000
Natuashish	1 x 3.5 MW	2.5 MW/1.25 MWh	$20,660,000
Hopedale	1 x 3.5 MW	1.5 MW/0.75 MWh	$19,420,000
Makkovik	3 x 800 kW	800kW/400 kWh	$17,848,000
Postville	800 kW	500 kW/250 kWh	$7,420,000
Rigolet	2 x 800 kW	750kW/375 kWh	$12,940,000
TOTAL			$98,948,000

D6.2. Southern Loop

Generation			
Community	**Wind**	**BESS**	**CAPEX**
Paradise River	1 x 100 kW	100 kW/50 kWh	$3,663,000
Cartwright	3 x 800 kW	800kW/400 kWh	$17,848,000
Black Tickle	1 x 800 kW	300 kW/150 kWh	$7,220,000
Port Hope Simpson	2x 800 kW	800kW/400 kWh	$13,048,000
Charlottetown	3 x 800 kW	800kW/400 kWh	$17,848,000
Norman Bay	1 x 100 kW	50 kW/25 kWh	$3,219,000
St. Lewis	1 x 800 kW	400 kW/200 kWh	$7,634,000
Mary's Harbour	3 x 800 kW	800kW/400 kWh	$17,848,000
L’Anse-au-Loop	None	None	N/A
TOTAL			$88,328,000

D7. Option 7

D7.1. Northern Loop

Transmission Lines			
Connected Communities	**Voltage**	**Distance**	**CAPEX**
Nain & Natuashish	69-kV	145 km	$84,100,000
Hopedale, Postville Makkovik	69-kV	232 km	$134,560,000
TOTAL			$218,660,000

Substations		
Community	**Description**	**CAPEX**
Nain	69 kV to 4.16 kV; 2 x 3.75/5/6 MVA	$5,000,000
Natuashish	69 kV to 25 kV; 2 x 3.75/5/6 MVA transformers	$7,700,000
Hopedale	69 kV to 4.16 kV; 2 x 2/2.7/3.3 MVA transformers	$5,000,000
Postville	69 kV to 4.16 kV; 2 x 1.5/2/2.5 MVA transformers	$4,700,000
Makkovik	69 kV to 4.16 kV 2 x 1.5/2/2.5 MVA transformers	$4,700,000
TOTAL		$27,100,000

*assume VB responsible for their own substation

Generation			
Community	**Wind**	**BESS**	**CAPEX**
Nain & Natuashish	2 x 3.5 MW	3.5 MW/ 1.75 MWh	$36,072,000
Hopedale, Postville Makkovik	2 x 3.5 MW	3.5 MW/ 1.75 MWh	$36,072,000
Rigolet	2 x 800 kW	750 kW/ 375 kWh	$12,940,000
TOTAL			$85,084,000

D7.2. Southern Loop

Transmission Lines			
Connected Communities	Voltage	Distance	CAPEX
Cartwright & Paradise River	69-kV	47 km	$13,630,000
Port Hope Simpson, Charlottetown, Norman Bay, St. Lewis, Mary's Harbour	25-kV	220 km	$41,800,000
TOTAL			$55,430,000

Substations		
Community	Description	CAPEX
Paradise River	69 kV to 4.16 kV; 1 x 1.5/2/2.5 MVA	$3,700,000
Cartwright	69 kV to 4.16 kV; 1 x 1.5/2/2.5 MVA	$3,700,000
Port Hope Simpson	69 kV to 25 kV - 12.5 kV; 2 x 2/2.7/3.3 MVA	$7,400,000
Charlottetown*	25 kV to 4.16 kV; 1 x 2/2.7/3.3 MVA	$2,800,000
Norman Bay*	25 kV to 4.16 kV; 1 x 1.5/2/2.5 MVA	$2,400,000
St. Lewis	25 kV to 12.5 kV; 1 x 1.5/2/2.5 MVA	$3,400,000
Mary's Harbour	25 kV to 4.16 kV; 1 x 1.5/2/2.5 MVA	$2,400,000
Mobile Substation		$5,500,000
TOTAL		$31,300,000

*NL Hydro exploring conversion of NB and CT to 25 kV, currently 4.16 kV

Generation			
Community	Wind	BESS	CAPEX
Cartwright & Paradise River	3 x 800 kW	800 kW/400 kWh	$17,848,000
Black Tickle	1 x 800 kW	300 kW/ 150 kWh	$7,220,000
Port Hope Simpson, Charlottetown, Norman Bay, St. Lewis, Mary's Harbour	2 x 3.5 MW	3.5 MW/ 1.75 MWh	$36,072,000

L'Anse-au-Loop	None	None	N/A
TOTAL			$61,140,000