Government of Northwest Territories
Inuvik High Point Wind Feasibility Study

Final Report

12 May 2017
Executive Summary

This report studies the feasibility of adding one or more wind turbines and energy storage devices at the town of Inuvik, in the Northwest Territories, Canada. Overall the Project Team finds that while challenging, it is technically and economically feasible to add the proposed components to the Inuvik grid.

The Project Team analyzed the wind resource and examined the energy output of several wind turbines. A grid model was then assembled to evaluate how well wind energy could blend to serve the local load. It was found that the moderate wind resource and the relatively large local electrical demand allow the effective use of commercial size turbines on site.

The supporting infrastructure was designed at a high level to cost both the civil components (access road and wind turbine foundation) and electrical components (transmission line, upgrades to substations and distribution network). The logistics required to bring equipment and machinery to Inuvik were investigated and a construction schedule was assembled.

The Project Team concludes that even with realistic assumptions and contingencies built into the model, there are significant potential benefits to the Project. Based on preliminary modelling SgurrEnergy estimates that considerable financial and greenhouse gas (GHG) savings can be achieved by the Project, ranging from $1.6 million to nearly $3 million in fuel savings and from nearly 4,000 tonnes to 7,000 tonnes of GHG offset annually. Renewable energy penetration for the new system is expected in the range of 18% to 28%. Depending on the configuration selected, the levelized cost of electricity at Inuvik is expected to either remain the same or go down slightly.
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Glossary

<table>
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<th>Definition</th>
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<td>AC</td>
<td>Alternating current</td>
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<tr>
<td>BoP</td>
<td>Balance of Plant</td>
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<td>CAPEX</td>
<td>Capital expenditure</td>
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<td>DC</td>
<td>Direct current</td>
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<td>Greenhouse gas</td>
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<td>Geological Survey of Canada</td>
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<td>Inuvik Engineering Ltd.</td>
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<tr>
<td>kV</td>
<td>Kilovolt</td>
</tr>
<tr>
<td>kWh</td>
<td>Kilowatt-hour</td>
</tr>
<tr>
<td>LCOE</td>
<td>Levelized cost of energy</td>
</tr>
<tr>
<td>LNG</td>
<td>Liquefied Natural Gas</td>
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<td>MERRA</td>
<td>Modern-Era Retrospective Analysis for Research and Applications</td>
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<tr>
<td>MW</td>
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<td>MWh</td>
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<td>Northwest Territories Power Corp.</td>
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<td>Point of common coupling</td>
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<td>Peak Ground Acceleration</td>
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<td>WACC</td>
<td>Weighted average cost of capital</td>
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<td>WASP</td>
<td>Wind Atlas Analysis and Application Program</td>
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<td>WTG</td>
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1 Introduction

The Government of Northwest Territories (GNWT or “the Client”) has appointed the Project Team to conduct a feasibility assessment for the potential integration of wind generation and energy storage equipment into the existing electrical grid that serves the town of Inuvik (the Project or Inuvik High Point). Inuvik is located in the Northwest Territories (NWT) of Canada.

The Project Team comprises Nihtat Corporation (Nihtat), SgurrEnergy Ltd. (SgurrEnergy), Inuvik Engineering Ltd. (IEL), and Hemmera Envirochem Inc. (Hemmera).

This report presents the methodology used and the results obtained by the Project Team.

An overview of the proposed Project location is shown on the map below.
Figure 1-1: Project Overview Map
2 Project Overview

The objective of the feasibility study undertaken by the Project Team is to determine whether it is technically feasible to install a wind turbine generator (WTG) and electricity storage components at the Inuvik site and to estimate the levelized cost of the energy (LCOE) produced by the new components. The Project context is described below.

2.1 Inuvik Community

Inuvik is a town in the NWT with a population of approximately 3,400. It is located along the Mackenzie River, approximately 200 km north of the Arctic Circle. It was officially established in 1954 and serves as the administrative headquarters for the Inuvik region.

Inuvik is accessible year round via air travel through the Mike Zubko Airport. For most of the year it is also accessible through the Dempster Highway, a 737 km road connecting Yukon and the Northwest Territories to southern Canada. The Dempster Highway closes for about a month twice a year, in late fall and late spring, when the route transitions from ice bridges to ferries and back. During summer the town can be accessed via barge along the Mackenzie River.

It is generally accepted that Inuvik uses approximately half of all the diesel burned in NWT for electricity generation. As such it is a significant producer of greenhouse gas and has been identified by the government as a prime target for improving the local energy generation scheme.

2.2 Local Stakeholders

In order to assess the viability of the Project, the following key Project participants have been engaged:

- The Client – Government of Northwest Territories Department of Public Works and Services (GNWT).
- The Utility – Northwest Territories Power Corporation (NTPC).

Feasibility Study Partners (the Project Team):

- Gwich’n Tribal Council - Nihtat Corporation (Nihtat).
- Renewable Energy Consultancy - SgurrEnergy Ltd. (SgurrEnergy).
- Environmental Consultancy - Hemmera Envirochem Inc. (Hemmera).
- Civil/structural Engineering Consultancy - Inuvik Engineering Ltd. (IEL).

According to the NWT Bureau of Statistics, the population in Inuvik is made up of over 38% Inuvialuit, 18% First Nations, 4% Metis and 36% of non-native inhabitants. In order to adequately reflect the interests of the local people, it was deemed critical that the Project be led by the Gwich’n Tribal Council.

A number of potential local and extra-territorial suppliers and contractors were contacted in the development of this feasibility report in order to provide input and support.
3 Wind Resource and Energy Yield Analysis

Previous wind resource monitoring campaigns and analysis have been completed at Inuvik by the Aurora Research Institute. Assessments of the local wind regime began in the area in 2012 in an attempt to find renewable generation to offset fossil fuel generation. This campaign began at a site named Storm Hills, approximately 60 km north of Inuvik. Measurements at this site appeared positive; however, the development cost for a project at this site was determined to be prohibitive by the Aurora Research Institute and the GNWT. Thereafter the GNWT and Aurora identified the Inuvik High Point location as a candidate development site closer to the town.

The Project Team has since been tasked to assess the viability of the Project including a review of the wind regime and potential energy yield for the site. This section discusses the results of the analysis of the wind resource collected at the High Point site.

3.1 Meteorological Measurement Campaign and Data Analysis

As part of the assessment process SgurrEnergy undertook a high-level analysis of the wind resource at the Project Site. Wind data were collected from a single 60 m meteorological (met) mast at the project site. The mast was installed on 30 November 2015 and removed on 9 September 2016 after it collapsed due to deficient anchoring. It should be noted that the amount of data collected amounts to less than a full year, which leads to increased uncertainty in resource modelling.

The mast was equipped with sensors at three different levels, including one heated sensor at 50 m. It should be noted that SgurrEnergy reviewed the installation report, but was unable to physically confirm the sensor set up as the tower collapsed prior to the Project Team’s site visit.

Based on a review of the mast installation report, it is noted that installed anemometers included three NRG Class 1, one WindSensor P2546C-OPR, and one NRG Icefree3. After data screening, approximately nine months of data were available for the analysis.

The observed wind characteristics are summarized in Table 3-1 below. The wind speed value presented is for the heated sensor at 50 m, which was later used in the analysis as the primary sensor because it showed the best data recovery rate at 97%. Non-heated sensors showed significantly lower data recovery rates that ranged between 34% and 41%. These sensors were primarily used for calculating shear at the site.

Figure 3-1 shows the monthly average wind speeds measured at the met mast, and Figure 3-2 contains the monthly wind roses.
Figure 3-1 Measured Monthly Wind Speeds

Figure 3-2 Monthly Wind Roses - 60 m Anemometers
Table 3-1: Overview of Mast 0602

<table>
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<tr>
<td>Measurement Period</td>
<td>30 November 2015 to 9 September 2016</td>
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<td>Duration (months)</td>
<td>9.7</td>
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<tr>
<td>Met Mast Height (m)</td>
<td>60</td>
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<tr>
<td>Location</td>
<td>68.3572°N 133.408407°W</td>
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<tr>
<td>Elevation (m)</td>
<td>245</td>
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<tr>
<td>Wind Shear</td>
<td>0.13</td>
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<tr>
<td>Average Measured Wind Speed at 50 m (m/s)</td>
<td>6.12</td>
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<tr>
<td>Long Term Wind Speed (m/s)</td>
<td>6.08</td>
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3.2 Long Term Wind Resource Adjustment and Extrapolation

There are multiple methods to apply a long term correction to the measured wind speed dataset. The most suitable methodology for a specific site is dependent on the quality of the long term data set and correlation between the on-site data and the reference source. Ideally the reference data should be correlated with the site data on an hourly basis, such that the wind speed distribution and direction data are also corrected during the long term correction procedure. Considering this, SgurrEnergy reviewed reference data from two available sources: Modern-Era Retrospective Analysis for Research and Applications, Version 2 (MERRA-2) reanalysis provided by NASA and NOAA rawinsonde data provided to SgurrEnergy by the client.

After careful consideration and analysis of both data sets, SgurrEnergy elected to use MERRA data as this data provided better temporal resolution as well as sufficiently good correlation on an hourly basis. Furthermore, the method and data set used are more readily acceptable by the lenders.

The long-term wind resource at the measurement location was predicted based on the measured wind distributions, which were then scaled to the predicted long-term wind speed using reference data from MERRA-2.

Concurrent datasets and relationships were examined on an hourly basis. Wind speeds were averaged directly while wind directions were averaged using a vector averaging technique. The quality of the synthesized data depends upon the quality of the correlation within each direction sector, and these sector-wise relationships were subsequently used to generate the synthesized datasets.

Wind direction data were plotted against the corresponding wind direction data from the concurrent mast datasets to check for wind veer trends between the locations.
A 15-year (January 2001 to December 2015) dataset from the nearest MERRA grid node (68.5 N; 133.75° W) was used to establish long-term wind speed adjustments for the site mast. The calculated hourly correlation coefficient of 0.58 was low, and therefore the monthly average correlations were also examined. The calculated monthly correlation coefficient is 0.67, which is also considered poor. Since both correlations would result in very similar long-term corrections in wind speeds, but the monthly analysis is based on only 18 data points, SgurrEnergy decided to use hourly MCP correlations for the long-term adjustment of the short-term wind resource measured at the Project site. This process led to a -0.7% correction and an average long term wind speed of 6.08 m/s representing the estimated long-term average wind speed on site at 50 m above ground. This value at the Project mast location was then extrapolated using directional shear values calculated from wind data measured at different heights of the 60 m mast to the proposed hub heights of 69 m, 75 m, 80 m and 98 m.

3.3 Wind Flow Modelling

A wind flow model was built for the Project area using the Wind Atlas Analysis and Application Program (WAsP) software package, which is considered suitable for the Project site due to its simple terrain and ground cover. Elevation data and photos taken during the site visit were used to create the topographic and roughness map used as input to the WAsP model.

In addition, the long term adjusted and extrapolated wind data at the Project mast location were used to initiate the wind flow model. In the absence of a full year of measurements, the energy yield values reported are considered indicative only and should be updated when a full year of wind data becomes available. The current wind map of the proposed Project location is shown in Figure 3-3.
Figure 3-3: Wind Resource at High Point at 98 m
3.4 WTG Selection Energy Yield Analysis

SgurrEnergy previously analyzed several WTG models that were compared based on energy yield, cost of purchase, transportation and operational track record in cold climate. Based on the information available at the time, SgurrEnergy recommended shortlisting Goldwind (GW82 - 1.5 MW), Enercon (E103 - 2.35 MW), EWT (DW61 - 900kW) and GE (1.85 MW – 87) WTGs as initially listed in the Wind Turbine Generator Sizing and Interconnection Recommendations report issued in December 2016 (document number: 6.16.11251.VAN.R.002).

During the course of the feasibility study, SgurrEnergy updated its recommendations based on additional information provided by WTG vendors and more optimized WTG location using the same methodology as previously described in the WTG Screening and Recommendation Report.

Goldwind was ranked as the world top WTG manufacturer based on total installed capacity in 2015 by Navigant Research. 98% of turbines sold by Goldwind in 2015 were installed in the Chinese market, which shows how little success the manufacturer has obtained outside its native country. Goldwind WTGs are generally very competitively priced which is one of the main reasons why SgurrEnergy decided to shortlisted initially. However in the course of the research performed for the current study, Goldwind provided further clarification on the availability of WTG models and stated that WTG with de-icing will not be available for the North American market in the foreseeable future. Based on this information, the Goldwind WTG was removed from the considered options.

GE was ranked at the number 3 position among all WTG manufacturers in 2015. Further to this, over 48% of all turbines installed in the USA in 2015 were made by GE according to the American Wind Energy Association and GE ranked third in Canada for the same year. These facts confirm that the USA based GE is very strong in North America. Initially the 1.8 MW WTG from GE was used for modeling. However further discussion GE suggested that the 1.8 MW line would shortly be discontinued and that the 3.8 MW WTG model would take its place around 2018. This new WTG would be more suitable for the site and be available with a true de-icing capability. Modeling showed it to be a great performer in producing a lot of energy in the site wind resource, however since this is a new model there is no track record to review. Based on the reputation of manufacturer GE and its success in Alaska, SgurrEnergy decided that it was acceptable to use this new model for the modeling even without having a specific history for the 3.8 MW model.

Germany based Enercon ranked sixth for worldwide installed capacity and fourth Canada in 2015. Enercon is generally recognized as one of the best manufacturers for the reliability of their products. Enercon WTGs are normally considered to have an expensive initial cost but to make up for it in the high level of performance they provide. The 2.35 MW E103 has a good track record and Enercon has experience working in remote northern environment in Canada. This WTG also boasts a demonstrated blade de-icing system that would be suitable for the conditions likely found at Inuvik.

EWT is a much smaller manufacturer compared to GE, Goldwind and Enercon, and primarily focuses on smaller niche markets, such as isolated grids. Headquartered in the Netherlands, EWT offers WTG models that have a smaller nameplate capacity than most of the main WTG suppliers while still carrying the full suite of control systems found in large WTGs. EWT does not offer a full de-icing system for the proposed turbines but can supply black blades, which will be a considerable disadvantage at Inuvik compared to the other options, given that solar resource is extremely limited in wintertime. The EWT models were quoted
at the highest per kW price, however their smaller nameplate capacities offer flexibility in the sizing of the whole wind farm, and there might be further economy of scale if multiple WTGs are purchased. It should be stated that EWT was the most responsive of the manufacturers contacted for the current study. The company also has significant remote grid and cold climate track record.

The results of updated analysis are presented in Table 3-2 and are used as an input for the HOMER model, which is described in Section 4.

Table 3-2: WTG Performance Summary

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<th>Model</th>
<th>Capacity (MW)</th>
<th>Rotor Diameter (m)</th>
<th>Hub Height (m)</th>
<th>Total Installed Capacity (MW)</th>
<th>Indicative Annual Energy Production* (MWh)</th>
<th>Gross Capacity Factor (%)</th>
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<td>103</td>
<td>98</td>
<td>2.35</td>
<td>7,228</td>
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<td>EWT</td>
<td>DW 61-900 kW (4 units)</td>
<td>0.90</td>
<td>61</td>
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<td>GE</td>
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</table>

*Includes only topographic and wake losses.

It should be noted that the annual energy production and gross capacity factor provided in the table above don’t account for other losses, such as WTG availability, icing, collection system, soiling and others. These additional losses are applied in the HOMER model to account for additional losses. The capacity factor is shown as a measure of how suited the WTG model is for the specific resource, but in itself it is not a useful financial metric. The values are presented here to show that the performance of the selected models is in the range expected for modern wind farms. See Section 4.3 for further details.

Based on the updated site and WTG information collected, individual manufacturer track record and WTG performance, SgurrEnergy recommends shortlisting turbines E103-2.35 MW from Enercon and 3.85 MW from GE and DW 61-900 kW from EWT for the Project.
4 Preliminary System Design

In order to ensure a seamless integration of the new proposed components into the existing grid, an integration/hybrid model study is critical. This study typically takes into account the specifications of the existing diesel and liquefied natural gas (LNG) generators and their limited and preferred operating parameters as well as the daily and seasonal electrical load profiles. The results of the study facilitate the selection and appropriate sizing of system components including the WTG(s) and the energy storage system (ESS), with the objective of maximizing fuel savings while maintaining adequate operation of the existing grid.

SgurrEnergy also considered a wind-diesel/LNG network, meaning a system not including batteries. Preliminary results suggested that such a system is feasible only when an advanced microgrid controller is used; this is further discussed in Section 4.2.

The overall objective of the system is to reduce the use of diesel fuel used for electricity generation in the community of Inuvik, but it also needs to make economic sense. Reducing dependence on fossil fuels will help make the community more sustainable and reduce its exposure to fuel shortage during the times when deliveries are not possible.

While in operation, the WTG system, supported by the ESS, is expected to cover the peak demand that is currently typically met by one or two diesel generators, allowing the diesel generators to be switched off completely for some time during windy days. It should be noted that that the LNG generator that is preferentially used to meet the base load will need to remain operating at all times.

SgurrEnergy has optimized the Project size based on the simulated monthly and daily load profiles using HOMER software, which is a standard tool for microgrid modelling that is developed in the National Renewable Energy Laboratory in the United States. SgurrEnergy has used this software effectively for several similar feasibility assignments and is of the opinion that the results provide a reasonable view of the system performance. The inputs for the model are described in more detail in the subsections below.

4.1 Load Profile

The Client and NTPC have provided SgurrEnergy with some level of load and generation data for the on-site diesel and LNG generation plant for the period from 2007 to 2016. Based on a review of the historical monthly generation records and 10-min daily load samples, SgurrEnergy simulated a 12 x 24 community load profile to be used in system integration design and modelling.

In recent years the community’s daily average electricity demand peaks in winter at about 4.0 MW, and drops to around 2.9 MW in spring and summer. Figure 4-1 shows the simulated monthly variations in electricity demand and Figure 4-2 shows a sample load profile of a winter day. The hourly demand rises from 3,500 kW in early morning to over 4,800 kW in late morning and stays relatively constant until early evening, when it starts to drop back again. The daily load profile of Inuvik resembles the typical load fluctuations of a residential community.

Based on these numbers, for the purpose of modeling the total yearly power requirement for the community was established at 31.5 GWh.
The Client has indicated that recent years may not be representative of future load at Inuvik as a downward trend has been observed. The impacts of load decrease on system operations are discussed in Section 4.5.

4.2 Existing System Configuration

The power system at Inuvik is a remote isolated grid, with all electricity generated locally from the NTPC Power Plant located in the center of the town close to the Mackenzie River (grid reference: 68.355251°N,
133.730171°W). The facility is made up of three large warehouse buildings, a small substation, diesel and LNG storage and associated heat recovery infrastructure.

4.2.1 Gensets

Two of the buildings on site house generators: the EMD plant has three large diesel generators and the K-Plant has one diesel generator and two natural gas generators. The specifications of the generating equipment are provided below in Table 4-1, as provided to the Project Team by NTPC personnel.

Table 4-1 Inuvik Generator Specifications

<table>
<thead>
<tr>
<th>Generator Name</th>
<th>Fuel Type</th>
<th>Rated Capacity (kw)</th>
<th>Allowed Capacity (kw)</th>
<th>Start up (mins)</th>
</tr>
</thead>
<tbody>
<tr>
<td>G3</td>
<td>Diesel</td>
<td>2500</td>
<td>2250</td>
<td>1 minute all year round (retrofitted with oil heater)</td>
</tr>
</tbody>
</table>
| G7             | Diesel    | 2800                | 2550                  | Summer: 4 – 5 minutes  
                          |            |                     | Winter: 15 – 30 minutes |
| G8             | Diesel    | 2500                | 2250                  | 1 minute all year round (retrofitted with oil heater) |
| G10            | LNG       | 2800                | 2520                  | Summer: 8 – 12 minutes  
                          |            |                     | Winter: 10 – 40 minutes |
| G11            | Diesel (Convert from LNG) | 2100 | 1890 | Summer: 4 – 5 minutes  
                          |            |                     | Winter: 15 – 30 minutes |
| G12            | LNG       | 2800                | 2520                  | Summer: 8 – 12 minutes  
                          |            |                     | Winter: 10 – 40 minutes |

Since diesel fuel costs more than LNG at Inuvik, the natural gas generators are typically used to meet the base load while the diesel units provide standby capacity. Generators G3 and G8 have been retrofitted with oil heaters which allows them to ramp up to full load within one minute of being fired up.

The control of the plant is effectively a manual system with inbuilt automated processes. The plant operator selects the desired generation unit(s) required to meet the electricity load for the town based on expected electricity consumption and the current generator maintenance schedule (see Section 4.2.3). Usually one natural gas generator is run to take the base load, and the remaining generators are stacked in advance to handle the expected load change, ready to be brought online automatically should the control systems detect any issues with the running generators. To transition between two units, the control system starts with reducing the output from both the running generators while simultaneously ramping up the incoming generator. Then when the departing generator nears shutdown the two
remaining generators take on the full load together. The control system manages the electrical load fluctuations by constantly maintaining an operating reserve. During system integration modelling (detailed in Section 4.5), the minimum load allowed for the diesel generators is set to 25% and to 40% for the natural gas generators.

4.2.2 Fuel Delivery and Storage

Natural gas was supplied to Inuvik from the Mackenzie Delta gas field until 2012, when this supply became restricted. Now the community has to rely completely on diesel and LNG delivered from southern Canada along the Dempster Highway at considerable costs. Twice a year, there is a period of approximately one month when the ice bridges that exist along the Dempster Highway do not have the capacity to carry any vehicles and the river is still frozen, preventing barge services. During this time Inuvik is cut off from any fossil fuel delivery. During these periods, the community’s 5,000,000 liter capacity diesel tank is fully utilized. The complete reliance on fossil fuels combined with the complexity of fuel delivery process is recognized as a risk to Inuvik in terms of the power system’s reliability and logistical complexity.

4.2.3 Maintenance

Table 4-2 below shows the maintenance events’ intervals and the associated costs as provided by the Client. Note that the natural gas generators G10 and G12, as well as G11 which currently runs on diesel but was converted from a natural gas generator, require substantially higher costs for overhauls.
Table 4.2 Generator Maintenance Intervals and Costs

<table>
<thead>
<tr>
<th>Unit #</th>
<th>G3</th>
<th>G7</th>
<th>G8</th>
<th>G10</th>
<th>G11</th>
<th>G12</th>
</tr>
</thead>
<tbody>
<tr>
<td>Fuel Source</td>
<td>Diesel</td>
<td>Diesel</td>
<td>Diesel</td>
<td>LNG</td>
<td>Diesel*</td>
<td>LNG</td>
</tr>
<tr>
<td>Oil Sample/Cost</td>
<td>500HR/ $2,000</td>
<td>500HR/ $2,000</td>
<td>500HR/ $2,000</td>
<td>500HR/ $2,000</td>
<td>625HR/ $2,000</td>
<td>625HR/ $2,000</td>
</tr>
<tr>
<td>Oil Filter Change/</td>
<td>1,400HR/ $3,000</td>
<td>1,400HR/ $3,000</td>
<td>1,400HR/ $3,000</td>
<td>1,500HR/ $3,000</td>
<td>1,250HR/ $3,000</td>
<td>1,250HR/ $3,000</td>
</tr>
<tr>
<td>Routine Service/Cost</td>
<td>2,000HR/ $5,000</td>
<td>2,000HR/ $5,000</td>
<td>2,000HR/ $5,000</td>
<td>3,000HR/ $50,000</td>
<td>2,500HR/ $40,000</td>
<td>2,500HR/ $40,000</td>
</tr>
<tr>
<td>Service Overhaul/Cost</td>
<td>4,000HR/ $10,000</td>
<td>4,000HR/ $10,000</td>
<td>4,000HR/ $10,000</td>
<td>6,000HR/ $75,000</td>
<td>5,000HR/ $70,000</td>
<td>5,000HR/ $75,000</td>
</tr>
<tr>
<td>Overhaul/Cost</td>
<td>8,000HR/ $60,000</td>
<td>8,000HR/ $60,000</td>
<td>8,000HR/ $60,000</td>
<td>12,000HR/ $440,000</td>
<td>10,000HR/ $450,000</td>
<td>10,000HR/ $450,000</td>
</tr>
<tr>
<td>Overhaul/Cost</td>
<td>16,000HR/ $80,000</td>
<td>16,000HR/ $80,000</td>
<td>16,000HR/ $80,000</td>
<td>24,000HR/ $600,000</td>
<td>20,000HR/ $650,000</td>
<td>20,000HR/ $700,000</td>
</tr>
<tr>
<td>Overhaul/Cost</td>
<td>24,000HR/ $400,000</td>
<td>24,000HR/ $400,000</td>
<td>24,000HR/ $400,000</td>
<td>48,000HR/ $850,000</td>
<td>40,000HR/ $750,000</td>
<td>40,000HR/ $800,000</td>
</tr>
<tr>
<td>Overhaul/Cost</td>
<td>48,000HR/ $600,000</td>
<td>48,000HR/ $600,000</td>
<td>48,000HR/ $600,000</td>
<td></td>
<td></td>
<td></td>
</tr>
</tbody>
</table>

*Converted from a NG generator.
Information regarding the current fleet age has also been requested but has not been provided to SgurrEnergy. The Maintenance Service Manager of NTPC at Inuvik, Kelly McLeod, has provided the approximate information shown below in Table 4-3.

### Table 4-3 Generator Usage

<table>
<thead>
<tr>
<th>Generator</th>
<th>Equipment Usage (Hours)</th>
</tr>
</thead>
<tbody>
<tr>
<td>G3 – Diesel (with oil heating)</td>
<td>~120,000</td>
</tr>
<tr>
<td>G7 – Diesel (without oil heating)</td>
<td>~20,000</td>
</tr>
<tr>
<td>G8 – Diesel (with oil heating)</td>
<td>~120,000</td>
</tr>
<tr>
<td>G10 – LNG</td>
<td>~40,000</td>
</tr>
<tr>
<td>G11 – Diesel (converted from LNG)</td>
<td>~10,000</td>
</tr>
<tr>
<td>G12 - LNG</td>
<td>~97,000</td>
</tr>
</tbody>
</table>

The specifications of the generators and all the information above regarding the operations and maintenance (O&M) schedule and costs have been considered in the system integration modelling (Section 4.5) and the Project’s financial model (Section 8). However because it was not possible to get an accurate account of the maintenance status of each generators with regards to their run hour history, SgurrEnergy did not account for the age of the generators in the model. The assumption was that each generator basically started the simulation as if it was brand new. This assumption is considered to be conservative because it lowers the actual cost of running the generators on site and thus reduces the modeled cost of energy from fossil fuels, which makes it harder for renewable energy to compete.

### 4.3 WTG Output and Losses

The estimated site wind speeds (1 year time series of data at 10-min resolution) that have been extrapolated to the proposed WTG hub heights are input into HOMER. Referring to the specifications and the power curves of the selected WTGs, the software simulates a power output profile for each WTG, which is then manually inspected and adjusted to match the estimated energy yield amounts discussed in Section 3.4 and to include the anticipated production losses.

All wind farms will experience some level of losses. The degree to which these losses are experienced depends on the WTG technology, O&M practices and contractors, environmental factors, grid considerations, and various other issues.
Table 4-4 outlines an initial list of losses anticipated for the Project. The losses will vary based on the final selected project design but the losses below are broadly considered applicable to a wind project in Inuvik. Note that a high level of uncertainty remains in the losses estimate at this stage.
<table>
<thead>
<tr>
<th>Corrections &amp; Losses</th>
<th>Correction factor</th>
<th>Loss (%)</th>
</tr>
</thead>
<tbody>
<tr>
<td>WTG Availability</td>
<td>0.950</td>
<td>5%</td>
</tr>
<tr>
<td>Grid Availability (24 hrs Downtime Assumed)</td>
<td>0.980</td>
<td>2%</td>
</tr>
<tr>
<td>Wake Losses (Internal)</td>
<td>1.000</td>
<td>none</td>
</tr>
<tr>
<td>Power Curve Performance (Impact of Conditions outside Performance Test Conditions)</td>
<td>0.975</td>
<td>2.5%</td>
</tr>
<tr>
<td>Electrical Transmission Efficiency</td>
<td>0.980</td>
<td>2%</td>
</tr>
<tr>
<td>Ancillary Systems</td>
<td>0.990</td>
<td>1%</td>
</tr>
<tr>
<td>Blade Contamination, Degradation &amp; Off-Design</td>
<td>0.990</td>
<td>1%</td>
</tr>
<tr>
<td>Icing Effects on WTG</td>
<td>0.92</td>
<td>8%</td>
</tr>
<tr>
<td>Overall Conversion Efficiency [%]</td>
<td>80.0</td>
<td>20.0%</td>
</tr>
</tbody>
</table>

4.4 Storage System Configuration

ESS’s, in the form of batteries or flywheels, are routinely used on a variety of micro-grid projects in order to shape and improve the stability of small grid systems. In recent years, significant funding has been directed towards research in the field of energy storage systems and various technologies are now available, each with their individual strengths and weaknesses.

In Inuvik, the use of the storage component in the ESS would be twofold: it would help smooth out the wind energy production by compensating for fluctuations in the WTG’s energy output, and also occasionally store some of the excess energy produced by the WTG when production would exceed the ability of the local grid to accept it. To minimize supply shortage, ensure system stability, and maximize renewable energy utilization, an advanced microgrid system controller should also be utilized.

Many ESS suppliers are considered suitable for the Project and offer customizable products that can be adapted to the energy and capacity specifications for the Project. The capability of each ESS configuration will both dictate the ability to control and respond to grid stability needs and balance system generation goals and priorities. An advanced control solution will be necessary in order to integrate the wind generation in a manner that results in effective load reduction in the thermal generation systems.

The overall architecture of the ESS will include the storage equipment, an inverter for changing the battery’s electrical input and output from DC to AC, an advanced controller, and physical storage system – likely a containerized system. As presently envisioned, the ESS will be installed within or adjacent to the
NTPC thermal generation station in order to best make use of site real estate, O&M operator monitoring and control, and injection closer to the Inuvik load center.

The component pieces of an ESS are described in the following subsections.

### 4.4.1 Energy Storage

Storage systems can be designed from a broad range of technologies such as pumped hydro energy storage, compressed air energy storage, and various types of batteries, flywheels, superconducting magnetic energy storage, chemical energy storage such as hydrogen energy storage systems, and finally thermal energy storage. A summary of the characteristics of energy storage technologies is shown in Figure 4-3.

Given the commercial and remote nature of the Project, it is assumed that any energy storage technology selected will need to be either mature or close to maturity in order to have an acceptable level of risk to the community, the utility, the developer, the investors and the lenders.

![Figure 4-3 Characteristics of Energy Storage Technologies](image)

Electricity storage technologies can provide a range of services to the electric grid and can be grouped around their power and energy relationship. Two of the key variables are output power (kW or MW) and energy stored (kWh or MWh).
Given the wide range of storage technologies and characteristics it is important to consider the specific application required for the Project. In order to maximize the use of wind power generation while also minimizing short-term response from the generators, the ideal ESS must be able to store power during peak generation and to release power to the grid during ‘calm’ periods, which requires technology that responds in short (second) to medium (several hours) timescales.

For the current project the Project Team considers that batteries are the most appropriate type of storage to be used. Multiple battery technologies have been considered, and further research will be needed as the Project advances to the detailed design stage because of the fast pace of advance in battery technology.

Batteries are expected to be housed in sea containers and are assumed to be located in the yard adjacent to the main powerhouses. This location is central on the Inuvik grid and would allow easier access for the system operators.

4.4.2 Inverters

Inverters are used to convert direct current (DC) that comes from the ESS’s battery cells to alternating current (AC) that is used on the distribution grid. Modern inverters are very efficient at converting energy but always cause some energy to be lost in the process.

In the Inuvik Project, the ESS would use a dedicated inverter specifically designed to accommodate the specifications of the batteries as well as to meet grid requirements.

4.4.3 Control System

The control system (controller) acts as the brain of any microgrid system such as the one considered at Inuvik. Advanced control systems allow for optimal operation of the various grid components and harmonious interaction between them. The controller typically monitors many data points, including the charge level of the battery cells in the ESS, power output of the WTG(s), the available generation from diesel generators and balances all of it with the instantaneous electrical demand on the grid. Advanced controllers are also capable of shutting down or activating the generators to streamline diesel and natural gas consumption and insure that an adequate baseload is maintained to provide required power quality on the grid.

In order to minimize BoP costs, maximize the use of existing facilities, and to allow easier operator access, it has been assumed that the control system will be placed either in the same containers as the batteries or in the climate-controlled building where the existing generators are kept. Current common practice is for ESS suppliers to provide containerized solutions with built-in fire prevention and suppression features. For example, Younicos’ Y. Cube 250/1 (250 kW/222 kWh) system is a 3 m x 2.4 m x 3.7 m enclosure with two compartments – the upper one housing the power conversion system and the lower section housing the battery array. If the ESS unit cannot be placed in a climate-controlled building, the suppliers would be able to provide a customised insulated ESS container. The cost of this winter package option has been factored into the financial model.

The design of the control system is a complex process and it must be performed based on complete information about all the other system components. At the current development stage, a placeholder has been set in the budget to allow for the controller but no discussions have taken place about which form
it will take. More detailed research on the controller for the system will need to be performed at a later date.

4.4.4 Suppliers

SgurrEnergy has considered a number of ESS suppliers, each of which has track record in microgrid and/or renewable energy ESS applications. Discussion of specific solutions is provided in Appendix B. ESS system original equipment manufacturers considered include:

- S&C Batteries
- Younicos
- Saft
- ABB
- EnSync
- Aquion

4.5 Scenarios Analysis

SgurrEnergy has optimized the Project size based on the simulated monthly and daily load profiles using HOMER software, which is a standard tool for microgrid modelling that is developed in the National Renewable Energy Laboratory in the United States.

Site wind conditions and WTG specifications input into HOMER were adjusted to match SgurrEnergy’s estimates detailed in Section 4.2. Generic efficiency curves were assumed for the existing diesel and natural gas generators because none were provided to SgurrEnergy for review.

The list of ESS products shown below were modeled into HOMER and results were compared to that of a business-as-usual scenario in which the community is powered by diesel and natural gas generators only, as well as a base case where the WTG(s) is integrated into the system without an ESS component.

- S&C SMS-250.
- Younicos Y.Cube.
- Aquion salt water battery systems.
- EnSync EnerStore 50 Agile Flow battery by EnSync.
- Primus Power EnergyPod.

For the feasibility study SgurrEnergy groups the ESS’s into two general categories: high power/short duration and low power/long duration. Three off-the-shelf products (though all can be customized) offered by three different suppliers are selected to be representative of each category, as shown in Table 4-5 below.
Table 4-5 Comparison of High Power/Short Duration and Low Power/Long Duration ESSs

<table>
<thead>
<tr>
<th>Category</th>
<th>Low Power / Long Duration Ratio</th>
<th>High Power / Short Duration Ratio</th>
<th>Extra High Power /Short Duration Ratio</th>
</tr>
</thead>
<tbody>
<tr>
<td>Product</td>
<td>Y.Cube 250/2 by Younicos</td>
<td>SMS-250 by S&amp;C</td>
<td>Intensium Max 20P by Saft</td>
</tr>
<tr>
<td>Max Power (kW)</td>
<td>250</td>
<td>340</td>
<td>144</td>
</tr>
<tr>
<td>Energy Content (kWh)</td>
<td>555</td>
<td>250</td>
<td>55</td>
</tr>
<tr>
<td>Duration @ Full Power (hours)</td>
<td>2</td>
<td>0.75</td>
<td>0.25</td>
</tr>
</tbody>
</table>

The configurations of the ESS products above were provided by the suppliers directly. The minimum allowed state of charge range between 5 to 20%. Cycle charging is assumed in the modelling. It should be noted that manufacturers typically customize their products based on specific site requirements. A rule of thumb is to equip the wind turbine with an ESS half of the turbine’s capacity, but project specific variables – average capacity factor, relative capacities of the wind turbine versus those of the generators and desired role of the wind-ESS component among others – ultimately decide the optimal ESS configurations. The selection of systems offered by manufacturers is also quickly evolving, meaning that the specifications shown above will likely differ from those of the ESS selected in the detailed design phase of the Project.

The potential fuel savings calculated using HOMER for each scenario featuring different combinations of WTG(s) and representative ESS products are summarized in Table 4-6. HOMER decides the stacking of generators based primarily on relative fuel costs, generators’ O&M costs, size of the gap between WTG output and the community’s load, and the generators’ operating constraints such as their minimum load. Note that no seasonal fuel availability constraints has been considered due to lack of relevant information.

Costs and savings estimates are based on fuel costs of $1.19/L for diesel fuel, and $0.85/m³ for natural gas which are the figures provided by the Client. Due to lack of information on the fuel curve and the actual performance of the generators, the model assumes generic generator fuel curves and automatically optimizes generator performance for economic considerations. The simulations are adjusted so that generators are operated at a load ratio between 80% and 90% average for the year. Greenhouse gas (GHG) estimates are based on IPCC emission factors and generic diesel and natural gas energy densities.

Scenarios A1, B1, and C1 assume no ESS component, but include advanced microgrid controllers. These systems are expected to manage the fluctuations in demand and WTG output by keeping an operating reserve on the generators with the help of smart signaling from the microgrid controller.

In A2 the 2.35 MW Enercon turbine is paired with 8 S&C’s high-capacity SMS-250 batteries, whose maximum discharge power is equivalent to the WTG capacity. More diesel saving is predicted in A2 than in A3, where the Y.Cube batteries have a total energy content equivalent to those of SMS-250 in A2 but a smaller total capacity (i.e. charge and discharge power).
In B2 the EWT turbines are accompanied by 5 SMS-250 batteries, whose maximum discharge power is about one third of the WTGs’ total capacity. More diesel saving is predicted in B2 than in B3, due to the much larger total discharge power of the SMS-250 batteries. The differences in fuel saving are also larger between B2 and B3 compared to those between A2 and A3, because the simulated system performance time series suggest that the storage capacity is not sufficient to temporarily “replace” the diesel generators when sudden drops in the wind farm’s output or increases in load occur.

The GE model has a maximum capacity larger than the system’s average load, which means potential for large amount of fuel savings, but it also demands powerful ESS configured to smooth out the WTG’s power output in order to limit the operational pressure exerted on the existing generator fleet. C2 and C3 both include large capacity battery packs. With a larger maximum discharge power and smaller overall energy content, the Saft batteries in C3 is shown to be the case in which the amount of diesel saving can be maximized.
### Table 4-6 Battery Configurations and Corresponding Annual Fuel Savings

<table>
<thead>
<tr>
<th>Scenario</th>
<th>Diesel (1,000 L/year) [1,000/year]</th>
<th>NG (1,000 m³/year) [1,000/year]</th>
<th>Cost/Savings (1,000/year)</th>
<th>GHG Cost/Savings¹ (Tonnes/year)</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>A</strong> Enercon E-103 2.35 MW (19% Renewable Penetration) - Savings</td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>A1</td>
<td>879 [1,046]</td>
<td>640 [544]</td>
<td>1,590</td>
<td>3,980</td>
</tr>
<tr>
<td>A2</td>
<td>1181 [1406]</td>
<td>493 [419]</td>
<td>1825</td>
<td>4545</td>
</tr>
<tr>
<td>A3</td>
<td>1046 [1244]</td>
<td>636 [540]</td>
<td>1785</td>
<td>4459</td>
</tr>
<tr>
<td><strong>B</strong> 4 x EWT DW-61 900 kW (24% Renewable Penetration) - Savings</td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>B3</td>
<td>927 [1103]</td>
<td>1191 [1012]</td>
<td>2115</td>
<td>5326</td>
</tr>
<tr>
<td><strong>C</strong> GE 3.8-130 (29% Renewable Penetration) - Savings</td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>C1</td>
<td>1141 [1358]</td>
<td>1222 [1038]</td>
<td>2396</td>
<td>6020</td>
</tr>
<tr>
<td>C2</td>
<td>1850 [2201]</td>
<td>689 [585]</td>
<td>2787</td>
<td>6935</td>
</tr>
<tr>
<td>C3</td>
<td>2492 [2965]</td>
<td>70 [60]</td>
<td>3025</td>
<td>7465</td>
</tr>
</tbody>
</table>

¹ GHG emissions reduction is calculated based on savings from fuel savings.
SgurrEnergy made the following observations during the system integration modelling for Inuvik using HOMER:

- The bulk of fuel savings are driven by the capacity of the WTG installed – for the three WTG models investigated, the ranking of fuel savings is the same as that of the installed capacities. For example, Using the 3.8 MW GE machine instead of Enercon 2.35 MW machine may increase the savings by 50%.
- With a smart microgrid controller, a substantial amount of diesel savings is achievable (scenario A1, B1, and C1), but the savings in diesel is much smaller compared to scenarios in which ESSs are installed. This is due to the fact that even if the level of power output from the WTGs is high during a short period on a given day, diesel generators cannot be shut down since they must run with an operating reserve to manage the fluctuations in load and wind power output.
- The ESS is expected not only to smooth the output from the WTGs, but sometimes also to pick up load swings, which currently are almost exclusively handled by the diesel generators (Figure 4-4). The simulation also shows that the ESS is used in the transition periods when the additional generator is starting up or shutting down, providing buffer and helping to reduce the generators runtime (Figure 4-5).
- The larger the maximum power and/or the energy content of the ESS is, the larger the fuel savings are. However, the ESS that is able to release larger amount of instantaneous power leads to more savings in diesel (comparing A2 and A3, B2 and B3, or C2 and C3). This is consistent with the fact that high-power ESS functions more like diesel generators in the whole system and both of them can respond to instantaneous fluctuations in demand more efficiently than the natural gas generators. It is also consistent with the current operation protocol that one natural gas generator runs almost full time to take the base load while a diesel generator is run at varying output levels to fulfil the rest of the load.
Figure 4-4  ESS Taking Swing Load

Figure 4-5  ESS Used during Generators' Transition
The model also shows that the total annual runtime of the generators decreases substantially at the presence of the WTG(s) and ESS: an estimated 2,000 hours of runtime reduction for diesel generators and 4,000 hours for natural gas generators under scenario B2 (four EWT DW-61 and five S&C SMS-250). However, since the information on historical annual runtime of the generators was not available, these estimated runtime reductions are highly uncertain.

It should be emphasized that without sufficient and accurate information about the current power generation system (no data on current generator annual run time, generator fuel curve, or exact fuel consumption level), there are significant uncertainties the estimated fuel savings in Table 4-6. Specifically, the sources of uncertainties and bias include:

- The performance of the diesel and natural gas generators is modelled based on generic fuel curves due to lack of information on the specific units currently serving the community. Also due to the lack of accurate data on historical fuel (especially natural gas) consumptions, the model has only been validated to a limited extent.
- The output profiles of the WTG(s) were modelled based on 10-min time series of wind speeds extrapolated to the proposed hub heights. In reality the wind is constantly changing, so the power outputs from WTG(s) are likely to have greater fluctuations than the modelled power output profiles. As a result, the benefit (and suitability) of high power ESSs might be underestimated in the current model.
- The trend of load at Inuvik is uncertain. The model is based on the electricity demand at Inuvik recorded in the period of 2011-2013 (average 3.6 MW), which is slightly higher than that of 2014 and 2015 (3.3 MW). This is based on the fact that more economic activities and electrification may occur in the coming years. Small differences in average load may lead to larger variations in fuel savings.
- Currently the operations of fossil fuel generators are semi-manually controlled by NTPC operators, who put generators on- or off-line based on their O&M schedule, expected load change, ramp-up time and personal experience. In HOMER modelling, the software optimizes the system performance based on iterations of calculations, but it does not use the same logic as the operators. The software assumes that by using a smart microgrid controller, operational issues such as block loading or blackstarts can be avoided. In reality, the performance of the system would depend heavily on how NTPC handles the daily operation and what role the controller is allowed to play.
- By the same token, with the incorporation of WTGs and ESS into the system, the mismatch between the generation and performance profile of a manually controlled system and an optimizer controlled system is likely to be greater.

The modelled scenarios which estimated fuel savings help understand the mechanism of the system and are fed into the preliminary project financial model discussed in Section 8, but the system integration and performance modelling will need to be revisited during detailed system analysis when the Project moves forward.

As suggested by the Client, SgurrEnergy has investigated the potential impacts resulting from a slowly decreasing electrical load at the Inuvik community. Due to the lack of confirmed information, the evaluation is not quantitative. When the combined output from the WTG(s) and the generators exceeds the load, the excess energy will be wasted unless the ESS absorbs it and/or the generators reduce their
output accordingly. It was found that due to the relatively low average capacity factors of the larger capacity WTG models studied (30% for 4x DW 61-900 kW and 28% for GE 3.8-130), the cases in which the wind picks up so that the total generation exceeds the load will become more frequent as average load level decreases. However periods of excess are expected to be generally short and the total amount of excess energy would be typically small enough to be balanced by generators’ load reduction and/or to be absorbed by the ESS. Therefore, the WTG and ESS configured to meet today’s demand at Inuvik are expected to still be suitable approaching the end of project life assuming a small or moderate rate of load decrease.

4.6 Fuel and Greenhouse Gases Savings

SgurrEnergy reviewed the load and generation data from the current diesel and LNG generation plant as well as the prospective generation from various WTGs located on site.

The typical load at Inuvik peaks in winter at about 4.0 MW and load variations resemble the typical load fluctuations of a small residential community. The current annual fuel use at Inuvik for electrical generation is estimated at 5,000,000 liters of diesel and 3,700,000 m$^3$ of natural gas which amounts to nearly $9$ M dollars, a figure that is highly susceptible to variations in fuel prices.

Based on preliminary modelling SgurrEnergy estimates that considerable financial and GHG savings can be realized by the Project. At the low end this includes $1.6$ million in annual fuel savings and nearly 4,000 tonnes of GHG offsets; at the high end this could be nearly $3$ million in fuel savings and 7,000 tonnes of GHG offsets annually. These figures are discussed in more detail in Section 8.

Considerable uncertainty remains in the fuel savings estimated due to a lack of data available for the analysis and limitations of software tools to take into account generator variations on a sub 10 minute time interval. SgurrEnergy recommends that the system integration and performance modelling be revisited during detailed system analysis should the Project move forward.
5 Preliminary Site Design

With consideration to wind resource, civil, and electrical design requirements, SgurrEnergy and IEL have created the preliminary project map as illustrated in Figure 5-1 and Figure 5-2.

The site selected for the location of the WTG(s) is a secondary hill just south of the present met mast location. Based on wind flow modelling for the Project, this area was found to be more energetic than the present mast location. As a base case, one WTG has been suggested at this location. Should two smaller WTGs be located at or near this site additional allowances will need to be made for road lengths and appropriate WTG spacing.

The construction map, Figure 5-2, depicts the approximate construction footprint for the Project. This includes assembly areas and crane pads, which typically have to match specific WTG manufacturer design specifications. Additional considerations for levelling or ground protection may be needed for vehicle parking and turnarounds, as well as for the area covered by the WTG rotor assembly if the assembly is completed in one lift (note that single blade lifts may reduce the level area required for the lift).
Figure 5-1: High Point Overview Map
Figure 5-2: High Point Construction Layout
5.1 Site Visit

The proposed turbine site visit was conducted on October 14th, 2016, from 10:30 to 11:30. The Project Team flew over the proposed road alignment and Project site by helicopter, and landed on the Project site for a walking tour. The ground was frozen but free of snow. Weather conditions allowed for good visibility, with an overcast sky but no fog or precipitation. Ground cover was primarily made up of moss, small shrubs, and other low vegetation. The southern end of the proposed road route was sparsely-treed muskeg with moss and small shrubs. Very little tree growth was observed on High Point.

5.1.1 Site Observations

A wind measurement campaign has been ongoing at this location over the past few years, however the met mast has collapsed twice, most recently in September 2016. A 10 m tower was erected to replace it and further met measurement is in the planning stage.

The terrain at the Project Site is effectively a plateau that slopes away gently to the north, east and west with small water bodies located 300 m to the east, 300 m to the west and 650 m to the north-west of the mast location. The length of the site (N-S) is approximately 500 m and the width (E-W) is 300 m.

The following series of images Figure 5-3, Figure 5-4, Figure 5-5 and Figure 5-6 provide a first-hand perspective from each of the cardinal directions taken from the location of the 60 m NRG met mast previously erected at the proposed project site.

![Figure 5-3: Northern View](image-url)
Figure 5-4: Western View

Figure 5-5: Southern View
5.1.2 Site Visit Findings

The Project Team carried out a site visit of the Project, including a helicopter fly-over of the proposed road alignment and Project area, and walk-about of project area. The main observations arising from these activities are as follows:

- The terrain at the proposed project site is a relatively flat plateau that slopes away gently in all directions. The ground was frozen but free of snow. Ground cover was primarily made up of moss, small shrubs, and other low vegetation. There were very few trees at the proposed project site.
- There are minor water bodies located 300 m to the east, 300 m to the west and 650 m to the northwest of the center point of the proposed project site.
- The length of the site (N-S) is approximately 500 m and the width (E-W) is 300 m.
- A collapsed NRG 60 m XHD tower was lying on the ground at the proposed project site.
- SgurrEnergy has been informed that a replacement 10 m tower was erected the weekend after the site visit was completed. This tower has heated instruments so that icing does not affect the data recovery.
- The proposed access road follows a route directly south from the proposed project site approximately 4.5 km to the point at which it intersects with the Dempster Highway.
- The slope of the terrain along the proposed route is gradual with an elevation gain of approximately 100 m from the Dempster Highway to the proposed project site.
- There are no major obstacles along the route of the proposed road such as rocky outcrops or deep ravines.
• Two small water courses were noted along the proposed route, the widest of which was approximately 2 m. Large bodies of muskeg terrain are near the route. Based on this preliminary survey it is thought that these water bodies and muskeg terrains can be avoided with relative ease.

• Tree cover on the proposed route ranges in height from approximately 0.5 m to 7 m. The cover is dense close to the Dempster Highway and becomes extremely sparse away from the road. At the project site there are very few trees growing.

• The ground conditions along the proposed route are consistent with the typical tundra landscape in the region which consists of thick vegetation, layer of mosses and lichens covering ice rich soil deposits.

The Project Team also visited key areas around the town of Inuvik that would assist with the compilation of the feasibility report:

• The NTPC power plant is in the center of the town of Inuvik. The plant is made up of multiple buildings, a substation and fuel storage facilities.

• There have been issues with birds hitting the voltage cables in the substation causing short circuits and resulting in outages and bird fatalities. This issue must be addressed to stop any future occurrences.

• While there is considerable heavy equipment available in the town of Inuvik, certain machinery such as cranes of the capacity to lift large WTG components will need to be brought to site. This will depend on the size of the WTG selected.
5.2 Preliminary Electrical Design

SgurrEnergy performed a high-level review of the interconnection configuration for the proposed system to the Inuvik grid. The review was based on information collected during the site visit, various documents provided by the Client and discussions with NTPC. The preliminary interconnection scheme for the WTGs and ESS is discussed below.

5.2.1 Collector Line and Interconnection to Airport Substation

The WTG will be located on High Point because it has the best resource near Inuvik. However, it is approximately 10 km away from the nearest interconnection to the grid. An electrical interconnection line will be required to bring the power produced to the existing grid. This line will likely be a three phase, 25 kV overhead cable to minimize losses and installation costs. The proposed layout goes south along the new access road from High Point to the Dempster Highway and then west along the Dempster Highway to the Inuvik airport substation.

There are five circuits that feed 25 kV electricity to the greater Inuvik area. The point of common coupling (PCC) with the Inuvik distribution network is planned on the 25 kV bus at the airport interconnection substation, which forms part of feeder 5. Some interconnection equipment including a circuit breaker and communication systems will be needed at the PCC to provide adequate protection both to the grid and to the WTG. The airport substation would be an ideal location for the PCC as it would allow easy addition of new infrastructure to existing facilities and would provide several options for connection configuration. It is also the closest point to the proposed WTG site. Figure 5-7 shows where the interconnection point would be on the airport substation single-line diagram (SLD). The full SLD is shown in Appendix D.

![Figure 5-7 Indicative Airport Substation Interconnection Point](image-url)
Some upgrades to existing equipment will likely be required depending on the nameplate capacity of the WTG installed and exact location of the PCC. In an e-mail dated 2 December 2016 NTPC’s transmission and distribution director listed the following potential facilities constraints:

- The 4.16 kV/25 kV transformer at the substation has a rated capacity of 1.5 MVA, which means that it may need to be replaced if the PCC is on the 4.16 kV bus and WTG capacity is greater than 1.5 MW.
- The distribution line from the airport to the town is made of #2 cable, which is insufficient to carry the power produced by the WTGs. An upgrade to 1/0 cable would likely be required.
- A new circuit breaker will be needed at the PCC to isolate the WTGs from the existing grid. A new transfer trip will be needed at the main feeder 5 breaker to avoid islanding.
- The addition of a battery system would facilitate ramp up and ramp down of wind generation.

The approximate cost of the new infrastructure and network upgrades was discussed with NTPC and figures were provided to SgurrEnergy. These cost estimates were used in the financial analysis presented in Section 8.

**Table 5-1 Collector Line and Electrical Upgrades Cost**

<table>
<thead>
<tr>
<th>Description</th>
<th>Total Cost</th>
</tr>
</thead>
<tbody>
<tr>
<td>New Powerline Cost per km</td>
<td>$250,000 / km</td>
</tr>
<tr>
<td>New Powerline length</td>
<td>10.3 km</td>
</tr>
<tr>
<td>New Powerline Cost Total</td>
<td>$2,575,000</td>
</tr>
<tr>
<td>New 25kV circuit breaker including transfer trip &amp; installation</td>
<td>$300,000</td>
</tr>
<tr>
<td>Additional substation work (ground grid, fencing etc.)</td>
<td>$10,000</td>
</tr>
<tr>
<td>Upgrade of Feeder 5 cable from #2 to 1/0 cost per km</td>
<td>$75,000 / km</td>
</tr>
<tr>
<td>Upgrade of Feeder 5 cable from #2 to 1/0 length</td>
<td>5.5 km</td>
</tr>
<tr>
<td>Upgrade of Feeder 5 cost total</td>
<td>$412,500</td>
</tr>
<tr>
<td>Replacement of Feeder 5 transformer to 6 MVA capacity</td>
<td>$500,000</td>
</tr>
<tr>
<td>WTG Step up transformer</td>
<td>Included with WTG</td>
</tr>
<tr>
<td><strong>Electrical system upgrades total cost</strong></td>
<td><strong>$3,797,500</strong></td>
</tr>
</tbody>
</table>
5.2.2 Energy Storage System

The proposed location of the ESS equipment is outside the existing powerhouse facility housing the diesel and LNG generators. Through conversation with NTPC and from the site visit it is apparent that this area includes a yard large enough to accommodate up to two 40’ shipping containers, which is what the ESS is likely to be housed in. The PCC for the ESS is assumed to be on the 4.2 kV bus at the powerhouse. This location is convenient because it is central on the Inuvik grid and physically near the grid operators.

The alternate PCC location is at the airport substation on the 4.2 kV bus. There is ample space available in that area and connecting to the grid very close to the WTG PCC would be beneficial, as the ESS would be better positioned to compensate any adverse impacts caused by the WTG on feeder 5. However this location is much more remote on the Inuvik grid, which would be detrimental if the battery is used for routine optimization of generator efficiency and power quality as more electrical losses would be incurred along the length of feeder 5.

The SLD showing interconnection of the ESS is shown in Appendix D.

Protection systems have not been evaluated at this stage and will be discussed with NTPC when a size has been finalized for the ESS. It is expected that a circuit breaker and remote control capabilities will be required.

5.3 Preliminary Civil Design

The location of the Project within the Arctic Circle and local permafrost conditions impose a very specific set of constraints on the civil engineering design. A preliminary presentation of design considerations and recommendations for the Project is outlined in the discussion below. Detailed project design will require the mixed expertise from civil and structural engineers experienced in northern construction standards and norms as well as specialists of the static and dynamic loading scenarios of WTGs and an understanding of the transportation and access needs for the Project.

5.3.1 Ground Conditions

5.3.1.1 Solid Geology

Surveys of the underlying solid geology are made publicly available by the Canada Geological Survey\(^2\). An excerpt from Map 178 (Geology, Inuvik, Northwest Territories) is shown in Figure 5-8 below\(^3\). The site and access route are marked in red.

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\(^3\) © Her Majesty the Queen in Right of Canada, as represented by the Minister of Natural Resources Canada, 2015
Both the site and access route are underlain by the Horton River Formation (Arctic Red Subsurface). This formation is a marine Lower Cretaceous unit described by Norris (1981) as consisting of shale and siltstone.

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Figure 5-8: Excerpt of geological mapping CGM 178 ©
5.3.1.2 Surficial Soils

The Geological Survey of Canada (GSC) provide mapping of the surficial soils and glacial features that can be expected on the site, including permafrost and drainage features. An excerpt of Map 31 (Aklavik) is shown in Table A-1 below.

![Figure 5-9: Extract of Geological Survey of Canada Map 31 (1979)](image)

The surficial soils on the site were deposited during the late Wisconsin glaciation that ended around 11,000 years ago. The valley shows glacial fluting (ridges) in an east to west direction indicating the direction of the glaciation, and the water bodies also reflect this movement.

The site is described as generally covered in clayey diamicton, which is a sediment resulting from dry-land erosion that is unsorted to poorly sorted and containing pockets of sorted silty and clayey materials. The diamicton is 4 – 12 m thick at the High Point (unit Mh), and 2–10 m thick on the upper access route (unit Mn). Depressions contain 2-8 m of lacustrine sediment and peat, with isolated areas of unmapped outwash. The lower section of the access road nearer the valley floor is described as 2-10 m thick clayey diamicton (unit Mv/Rp).

The upper diamicton in the active layer was exposed in an anchor point excavation for the meteorological mast (Figure 5-10). This shows as poorly sorted clayey till as predicted by the mapping, albeit this is not a representative survey and gives no indication of depth.
5.3.1.3 Seismic Intensity

The National Building Code of Canada 2015 defines the design criteria for ground motions, with a 2% probability of exceedance in 50 years (0.000404 per annum). These are interpolated for the site from 11 surrounding points using the Natural Resources Canada website facility as shown in Figure 5-11 below. The records shown in the image are for Peak Ground Acceleration (PGA), measured in units of gravity, g (9.81 m/s²).

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5 Image from SgurrEnergy site visit of 12th October 2016

The results show a PGA of 0.121g, which is considered a very high value that would be used for residential buildings. For industrial plant such as a WTG it is normal to use a lower return period for design, usually the 10%/50 year (1/475 year or 0.0021 per annum probability), and these values are summarized in Table 5-2 below. It is recommended that these values are used for design purposes, although it is also noted that seismic forces rarely exceed extreme wind overturning forces in WTG design. Values for other return periods are shown in Table 5-2.

Table 5-2: Seismic Criteria for the WTG Location

<table>
<thead>
<tr>
<th>Spectral acceleration (g) by period (s)</th>
<th>PGA</th>
<th>PGV</th>
</tr>
</thead>
<tbody>
<tr>
<td>0.05 0.1 0.2 0.3 0.5 1.0 2.0 5.0 10.0</td>
<td>g</td>
<td>m/s</td>
</tr>
<tr>
<td>0.060 0.087 0.112 0.110 0.093 0.063 0.035 0.012 0.0047</td>
<td>0.050 0.064</td>
<td></td>
</tr>
</tbody>
</table>
5.3.1.4 Permafrost

Permafrost is ground that remains continuously frozen throughout the year. The upper layers can, however, thaw seasonally and refreeze (active zone), giving rise to a number of engineering challenges to the design of foundations and roads.

Natural Resources Canada compiles ground temperature data from across the Canadian North and this data can be found on the National Snow and Ice Data Centre’s website (Figure 5-12). This shows the Project site lying in a zone of continuous permafrost.

Figure 5-12: National Snow and Ice Data Centre borehole plan

The boreholes nearest the site have been interrogated, and these are described in Appendix A, with a visual summary in Figure 5-13 overleaf. This predicts a permafrost depth between 5 m and 9 m by interpolation, however the boreholes rarely extended below 10 m depth and so it may be deeper in places.

GSC mapping describes the upper site as an area of continuous permafrost. Rare taliks (areas of unfrozen ground) can be found in depressions, and these would be expected to lie under the larger waterbodies.

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7 http://nsidc.org/data/G02190
The ice content of diamicton is described as low to medium due to presence of ice lenses (commonly having reticulate pattern) with rare occurrences of massive ice accumulation possible under the site.

Figure 5-13 : Superimposed NSIDC borehole data

Where the ground is rich in ice a polygonal structure forms due to the creation of ice wedges, and this is visible on aerial imagery. An example is shown adjacent to the WTG site in Figure 5-14 below.
There are ice rich areas scattered across the area and the access corridor. They are generally to be found on gentler slopes of 2 - 3% and adjacent to seasonal watercourses. It is unlikely that they can be wholly avoided by the access road.

5.3.1.5 Surface Water

There are isolated waterbodies around the subject site formed by trapped water in the undulating terrain. It is anticipated that all of the smaller bodies will freeze in winter, but the larger lochan of c42Ha area nearer the Dempster Highway may have sufficient depth to insulate the ground beneath leading to a talik, a section of ground that does not freeze. It is recommended that these are avoided by the access route, which appears feasible though this may result in an increase in road cost.

Seasonal watercourses generally link these water bodies and drain them during the spring thaw and summer storms. It is anticipated that some culverted crossings shall be required for the access route.

5.3.2 WTG Foundations

The permafrost and the climate are the main considerations when considering foundation solutions. The key aims are to:

- Avoid reliance on the active layer, which may increase in depth due to annual variations or climate change.
- Consider the uplift forces produced when the active layer refreezes during winter.
- Recognize that concreting works are very challenging during extreme cold.
- Recognize the very high overturning and rotational forces induced by WTG operation, as well as the dynamic nature of the load created by the blade rotation.

Note it is possible to build a foundation on permafrost provided it is ensured that it shall remain frozen.

Based on desktop and online information it is anticipated the ground conditions at the selected WTG location shall consist of:
1. 150-250 mm topsoil.
2. 1-2 m active layer of clay diamicton.
3. 6-10 m layer of clay diamicton permafrost.
4. Bedrock of shale/siltstone to depth exceeding 40 m.

The depth of the bedrock and the permafrost layer are the key engineering parameters that shall require intrusive investigation. At present there are three suggested foundation solutions that depend on the depth of bedrock/permafrost:

- If bedrock is less 10 m depth, consider a steel piled solution that has a suitable rock socket to take tensile forces. If a suitable socket length is problematic, the use of grouted rock anchors is effective in clamping the foundation to the rock, with a counteracting wall thickness of steel pile. The WTG tower may be supported on an elevated platform of steel or concrete to isolate from the active layer.

- If bedrock is greater than 10 m consider the use of adfreeze piles that actively mobilize the mass and rigidity of permafrost for both tensile and compressive forces. These specialist products require active thermocouples to ensure that the permafrost remains frozen, including against the risk of warming by the pile either through absorption of radiant heat or from transformers in the base of the tower. This may require more research on the dynamic effect of the tower movement on the freezing process. The WTG tower may be supported on an elevated platform of steel or concrete to isolate from the active layer.

- If bedrock is less than 2 m consider a traditional gravity foundation placed on prepared rock, supplemented with rock anchors to allow a reduction in concrete quantities to the minimum.

5.3.3 Access Road

The geometric and strength requirements for the access road to the plant are normally determined by the turbine supplier as the lengths and weights of components, and the size and traction of the vehicles delivering them, are the determining factors.

In the operational phase there will be a need to maintain four season access to the WTG for fault fixing and routine maintenance, as well as to deliver potentially large and heavy replacement parts. This makes the option of building the WTG using only a winter road much less attractive. It is further estimated that since there isn’t enough snow on site to build a 4 km road, snow and water would need to be trucked in, causing the cost for a winter road to be higher than usual. The assumption was made that it would be preferable to the Project to build a four season road.

In the case of this Project the access road exceeds 4 km over challenging ground conditions (permafrost lenses, saturated clays, seasonal watercourses) for a single turbine installation, which is not a standard approach. It is reasonable to assume that non-standard equipment may be used to complete the deliveries of the main components that would allow the geometry constraints to be relaxed. This may include the use of tracked equipment such as large dozers to assist deliveries, or even transfer the trailer to the tracked equipment to complete the delivery. In winter when all ground is frozen it may be possible to access the site with tracked machinery without the need for a formal road.

It is expected that the access road shall meet the constraints listed below;
• Consideration of floating roads using geogrids on the softened sections of till.
• Use of embankments of 1.2 m+ depth of engineered granular fill over ice rich areas.
• Limit culverted crossings where possible, and detailing to allow culverts to perform in the thaw even when partly frozen themselves.
• Gradients limited to 10% for unassisted vehicle delivery, up to 20% for assisted towed deliveries.
• Minimum road width of 4.5 m ideally with intervisible passing lanes.
• Visibility splay and turning radii at the Dempster Highway junction to be agreed with the relevant Roads Authority.
• No turnaround included at the WTG location in order to save on aggregate quantity. This is based on the assumption that delivery trucks can either back out all the way to the Dempster Highway or that the site crane can be used flip the trailers and allow trucks to drive out. Since the total number of deliveries is low this assumption is considered feasible.

5.3.3.1 Road Layout

The road layout and fill requirements were designed by IEL. The location of the proposed access road was selected based on the alignment to the site and the access to quarry locations in the vicinity to the proposed Project site. The proposed alignment of the access road to the site intersects the existing Dempster Highway near km 253.5 at approximately 90 degrees and has a bearing directly north with a straight alignment. The approximate distance of the site is 4.8 km. Appendix E shows detailed drawings of the access road plan, profile and cross-section as prepared by IEL.

The road has been designed to minimize horizontal and vertical curves and can most likely maintain a desired vertical curvature at road crests and sags for the movement of oversized loads to the site. The gradients along the alignment can also most likely be designed to provide desirable grades less than 10%, with no switchbacks along the proposed alignment.

The approximate area of the site, identified by the general topography and the subsequent GPS waypoints taken on the site visit, was 53,454 m². The length (N-S) was approximately 177 m and the width (E-W) was 302 m. The vertical elevation variation was approximately 1.0 to 1.5 m from the midpoint of the site to the outside limits of the site area. The proposed alignment for the access road does not intersect any substantial water bodies, such as lakes or rivers. There were some noticeable drainage channels and potential muskeg, although quite possibly outside of the road embankment footprint.

The ground conditions along the proposed alignment are consistent with the typical tundra landscape in the region, which consists of thick vegetation layer of mosses and lichens covering ice rich soil deposits. This project site and proposed alignment will be constructed in an area comprised of entirely permanently frozen ground, i.e. permafrost. Permafrost is susceptible to ground disturbances. Ground disturbances, such as the construction of a road and a site pad, will alter the ground thermal regime and usually results in the permafrost melting and degrading. Conventional arctic construction practices aim to minimize road movements resulting from the melting of the permafrost, and include a minimum embankment thickness to project the permafrost. The minimum embankment thickness in permafrost conditions is typically greater than the minimum embankment thickness required to support loads in non-permafrost ground conditions.
The construction of the road embankment and the grading of the site pad on permafrost ground would consist of a fill-only design with geotextile between the original ground and the constructed embankment to minimize disturbance of the original ground and movement of embankment. The original ground vegetation should remain in place and intact to provide an insulated mat for the permafrost within the original ground. A detailed geotechnical investigation and analysis, prior to the detailed design, would provide an understanding of the existing ground conditions and temperatures, as well as a recommended embankment thickness for the construction of the new access road to attempt to preserve the underlying permafrost. IEL road and design specifications are noted in Table 5-3.

### Table 5-3 Road Specifications

<table>
<thead>
<tr>
<th>Road Design Option</th>
<th>Detail</th>
</tr>
</thead>
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<tr>
<td>Length</td>
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</tr>
<tr>
<td>Max vertical slope (K value)</td>
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</tr>
<tr>
<td>Max. Grade</td>
<td>10 %</td>
</tr>
<tr>
<td>Design Speed</td>
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</tr>
<tr>
<td>Lane Width</td>
<td>3 m</td>
</tr>
<tr>
<td>Crossfall %</td>
<td>2%</td>
</tr>
<tr>
<td>Road Width</td>
<td>6 m</td>
</tr>
<tr>
<td>Side Slope - Vertical : Horizontal</td>
<td>1 : 1.3</td>
</tr>
<tr>
<td>Fill volume - Road</td>
<td>84,525 m³</td>
</tr>
<tr>
<td>Fill volume – WTG Pad Area</td>
<td>1,145 m³</td>
</tr>
<tr>
<td>Total Fill</td>
<td>85,670 m³</td>
</tr>
<tr>
<td>Road cost at $60/m³</td>
<td>$5,140,200</td>
</tr>
</tbody>
</table>

The current road design would permit transport of equipment with minimal issues. Further study on road design options, including routing and design refinement may result in a more cost effective road design. Significant cost savings may exist where the fill volume can be reduced by relaxing road gradient requirements and reducing the road width.
5.3.3.2 Proposed Construction Methodology

The quarry locations that would be proposed for the construction of the access road are in close proximity to the access from the Dempster Highway and located at km 251 and km 260. These two quarry locations would provide frost free materials from local bedrock outcroppings. Within the use of these materials, the construction of the proposed access road would not be seasonally dependent. It should be noted that both quarries are expected to have materials available in quantities greater than required for this Project by an order of magnitude.

The typical construction methodology for this type of road construction would consist of the drilling and blasting of bedrock materials within the quarry, followed by the stockpiling of embankment materials. Once the tree cover has been removed and geotextile placed at the base of the proposed road embankment, these materials would be loaded and hauled to site, dumped and placed on the layer of geotextile covering the existing ground. The material would be spread by a dozer to design grades in lifts not exceeding one meter in thickness. The placed material would then be track packed and rolled with a steel drum vibratory roller. Once the embankment is complete, manufacture crushed aggregate required for the subbase and base materials can be placed and compacted conventionally to design grades. If any culverts are required to channel drainage, they would be installed during the construction of the embankment.

5.4 Conclusions

Based on the information collected from site and exchanges with NTPC, no major hurdles have been identified on the electrical side. A new 25 kV line of approximately 10 km will be required to interconnect the WTG to the airport substation. Upgrades will be required at the airport substation to connect the WTG, at the main powerhouse to connect the ESS, and potentially on some section of the collection system. The estimated costs for new infrastructure as well as anticipated upgrades to the existing grid have been accounted for in the financial model. Further design work will be required at a later stage of the Project, and more detailed requirements will be needed from NTPC as to how the process should take place.

The new road length to the Project is expected to be 4.85 km with a maximum grade of 10%. This grade is slightly above the typical maximum grade permissible for the transport of large WTG components. However, travel on these grades should still be possible with the proper equipment. Grades may further be relaxed where necessary if a towing tractor is used to assist the transport of large equipment on steeper slopes. In this scenario, less fill may be necessary reducing road costs.

Several concepts are being considered for the turbine foundation depending on the actual subgrade conditions at the site. Further geotechnical investigation will be required to select the adequate design, but the Project Team considers that all cases are feasible.

The civil design component of the Project represents the single largest cost for development. Consequently, additional studies and geotechnical work could better quantify and qualify design options available for the Project and reduce overall costs. These studies would bring sizeable benefits in terms of reduced uncertainty with regards to the overall cost of development.
6 Regulatory Approvals and Permitting Review

Hemmera Envirochem Inc. (Hemmera) was contracted to conduct a review of potential regulatory constraints for the Project. To identify requirements and assess potential risk, the analysis focuses on the environmental assessment process, permitting requirements, and land tenure and resource use.

The Mackenzie Valley Environmental Impact Review Board (Review Board) is the main instrument responsible for the environmental impact assessment process in the Mackenzie Valley (Review Board, 2004). The first step in the EIA process, the preliminary screening, is generally conducted by a land and water board (e.g. the Gwich’in Land and Water Board (GLWB) for projects in the GSA). If the preliminary screening concludes that the proposed development might cause significant adverse impacts or generate public concern, then the development is sent to the Review Board for an environmental assessment (Review Board, 2004).

It is anticipated that the Project will undergo a preliminary screening, with the GLWB as the primary reviewing agency. It is Hemmera’s view that the Project is unlikely to be referred for environmental assessment as few items and effects are emerging as high-risk. Overall, environmental and community risks associated with the Projects are considered low. Effects to biological components were considered of moderate risk due to potential impacts to migratory birds during Project operations and potential direct and indirect impacts on boreal caribou. Additional understanding of these issues is recommended. Consultation with agencies and Aboriginal groups will be required to gain a better understanding of issues specific to the Project. Risks associated with permitting and tenuring are expected to be low.

This regulatory review is a precursor to necessary baseline studies and environmental assessment based on a project description, and is not considered a legal opinion with respect to named legislations.

For further details see Appendix B.
7 Preliminary Construction Schedule and Logistics

The construction of the Project within the Arctic Circle and on permafrost creates a number of construction and logistical constraints that are not typical of wind farm construction. This results in increased importance of adequate project planning, adaptation of typical project designs and schedules, and increased Project costs as compared to typical wind farm construction scenarios.

The Project Team has decided to take a conservative approach when estimating Project time requirements. The full development process and timeline for the Project is expected to last 2.5 years with the construction phase lasting 15 months. Favorable circumstances and more detailed planning could reduce these lead times.

7.1 Construction Schedule

Paramount consideration must be given to the seasonal constraints imposed by the location of the Project. The effects of cold weather, transport and equipment access (discussed in Section 7.2) will dictate the construction logistics. In addition, the erection of a single WTG (or two) in a small remote project leaves little flexibility for reorganizing work stages where individual tasks or deliveries are delayed in order to maintain the original construction schedule and limit the impact of delays.

An indicative Project schedule is provided in Figure 7-1. The basis for the project schedule comes from discussions with local contacts, equipment suppliers, and internal SgurrEnergy and IEL knowledge of the practicalities of constructing and commissioning wind farms in cold climates. The project schedule is divided into three main sections:

- Pre-Development stage: where the Client is anticipated to make a decision and mobilize the administrative and financial aspects of the Project.
- Development stage: where the project design is expanded from the high level concept described herein to a mature project with all the relevant contracts and permits applicable for development and engineering documents in place.
- Construction stage: where civil, electrical, and mechanical works can be undertaken in advance of operations.
### Figure 7-1: Indicative Project Schedule

<table>
<thead>
<tr>
<th>Name</th>
<th>Begin date</th>
<th>End date</th>
<th>Duration</th>
</tr>
</thead>
<tbody>
<tr>
<td>Barging Operations Window 2018</td>
<td>02/07/18</td>
<td>30/06/18</td>
<td>43</td>
</tr>
<tr>
<td>Barging Operations Window 2019</td>
<td>06/07/19</td>
<td>30/06/19</td>
<td>43</td>
</tr>
<tr>
<td>Winter Road Transport Window 2018</td>
<td>01/12/17</td>
<td>26/02/18</td>
<td>02</td>
</tr>
<tr>
<td>Winter Road Transport Window 2019</td>
<td>03/12/18</td>
<td>28/02/19</td>
<td>02</td>
</tr>
<tr>
<td>Inuvik Project</td>
<td>01/05/17</td>
<td>14/08/19</td>
<td>082</td>
</tr>
<tr>
<td>Pre-Development</td>
<td>01/05/17</td>
<td>25/07/17</td>
<td>60</td>
</tr>
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<td>GNTT Project Request</td>
<td>01/05/17</td>
<td>25/07/17</td>
<td>60</td>
</tr>
<tr>
<td>GNTT Project Confirmation</td>
<td>01/05/17</td>
<td>01/05/17</td>
<td>0</td>
</tr>
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<td>Development Stages</td>
<td>26/07/17</td>
<td>10/04/10</td>
<td>100</td>
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<tr>
<td>Wind Resource Refinement</td>
<td>26/07/17</td>
<td>08/02/18</td>
<td>140</td>
</tr>
<tr>
<td>Detailed Design</td>
<td>26/07/17</td>
<td>17/11/17</td>
<td>60</td>
</tr>
<tr>
<td>Detailed Design Complete</td>
<td>18/10/17</td>
<td>18/11/17</td>
<td>0</td>
</tr>
<tr>
<td>Environmental Studies and Per...</td>
<td>07/08/17</td>
<td>18/04/18</td>
<td>180</td>
</tr>
<tr>
<td>Geotechnical Studies</td>
<td>07/08/17</td>
<td>25/08/17</td>
<td>15</td>
</tr>
<tr>
<td>NTPC System Impact Modelling</td>
<td>18/10/17</td>
<td>12/12/17</td>
<td>40</td>
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<tr>
<td>Construction Stage</td>
<td>19/04/18</td>
<td>14/08/19</td>
<td>334</td>
</tr>
<tr>
<td>Civil Works</td>
<td>10/04/18</td>
<td>07/02/19</td>
<td>203</td>
</tr>
<tr>
<td>Roads</td>
<td>18/04/18</td>
<td>22/01/18</td>
<td>150</td>
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<tr>
<td>Cleared</td>
<td>16/04/18</td>
<td>15/06/18</td>
<td>40</td>
</tr>
<tr>
<td>Road Construction</td>
<td>03/05/18</td>
<td>22/11/18</td>
<td>140</td>
</tr>
<tr>
<td>Foundation (Piling/Anchoring)</td>
<td>23/11/18</td>
<td>07/02/19</td>
<td>53</td>
</tr>
<tr>
<td>Drill Rig Mobilization</td>
<td>23/11/18</td>
<td>09/12/18</td>
<td>10</td>
</tr>
<tr>
<td>Drilling and pile install</td>
<td>07/02/18</td>
<td>24/12/18</td>
<td>12</td>
</tr>
<tr>
<td>Capping</td>
<td>26/12/18</td>
<td>26/10/19</td>
<td>1</td>
</tr>
<tr>
<td>Freeze protection</td>
<td>27/12/18</td>
<td>24/04/19</td>
<td>20</td>
</tr>
<tr>
<td>Ring/Base Installation</td>
<td>25/01/19</td>
<td>07/02/19</td>
<td>10</td>
</tr>
<tr>
<td>Crane Pad and Lift Down</td>
<td>23/11/18</td>
<td>04/12/18</td>
<td>8</td>
</tr>
<tr>
<td>Electrical (NTPC)</td>
<td>04/05/18</td>
<td>10/12/18</td>
<td>132</td>
</tr>
<tr>
<td>Circuit Breaker at Airport</td>
<td>04/01/18</td>
<td>06/06/18</td>
<td>5</td>
</tr>
<tr>
<td>Upgrade Feeder 5 Code</td>
<td>11/05/18</td>
<td>05/09/18</td>
<td>60</td>
</tr>
<tr>
<td>Replacement of Feeder 5 Tr.</td>
<td>06/09/18</td>
<td>14/08/18</td>
<td>7</td>
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<tr>
<td>25KV Overhead Line Installa</td>
<td>17/09/18</td>
<td>19/10/18</td>
<td>80</td>
</tr>
<tr>
<td>Erection and Commissioning</td>
<td>10/05/19</td>
<td>10/08/19</td>
<td>60</td>
</tr>
<tr>
<td>Mobilization and Weather Co.</td>
<td>10/05/19</td>
<td>15/07/19</td>
<td>45</td>
</tr>
<tr>
<td>Assembly and Lift</td>
<td>16/08/19</td>
<td>02/08/19</td>
<td>14</td>
</tr>
<tr>
<td>Commissioning</td>
<td>05/08/19</td>
<td>14/08/19</td>
<td>7</td>
</tr>
<tr>
<td>COD</td>
<td>16/08/19</td>
<td>15/08/19</td>
<td>0</td>
</tr>
</tbody>
</table>
The pre-development stage consists of a three month period for the ultimate go/no-go decision by the Client and the mobilization of financing tools to advance for the Project. Currently this is expected to begin in the Client’s 2017 fiscal year although the timeline is only estimated and will be subject to change. At present, SgurrEnergy understands that the Project will be spearheaded by the GNWT with potential funding support from the Government of Canada.

The development stage is anticipated to last approximately nine months. The critical path for this stage is related to the detailed design, permit confirmations, and procurement schedule for the Project.

Environmental and interconnection permits could require considerable time to secure. Environmental permits will depend on indicative design plans as well as seasonal impacts related to flora and fauna surveys. Interconnection permits will depend on system impact studies which will require various parts of the detailed design work to be completed, however the well-established relationship between the GNWT and the NTPC could make the process smoother than in other locations. Detailed design work will be completed using an iterative process with adaptations from the environmental and interconnection studies as well as on the ground and geotechnical surveys.

The construction stage is anticipated to last approximately 15 months. This timeline is strongly dependent on the initiation of construction activities and seasonal impacts. The majority of the construction stage for the Project is related to civil and electrical activities, some of which can be completed in parallel. It is also possible to reduce the construction period by planning for WTG erection during the winter months. However, delivery of heavy equipment (discussed in Section 7.2) and crane operation may require a summer installation schedule. Further investigation will be required once components and machinery are firmed up.

Road construction to provide access to the WTG location(s) is what will ultimately drive the construction schedule. This new road access is needed in order to install the WTG foundation(s) and the Project’s overhead electrical lines and is estimated to take between 6-8 months of primarily winter construction. Thereafter the process of drilling piles or installing rock anchoring (see Section 5.3.2) will take place. This work is also recommended to take place during the winter months in order to minimize impacts to permafrost and to ensure the foundation is well anchored in advance of full WTG loading.

In parallel with this, the electrical system will be built. This will include the construction of the 25 kV line envisioned for the Project and the network upgrades needed to accommodate the new energy injection at the PCCs for both the WTG and the ESS.

The erection of the WTGs themselves is expected to last approximately two to three weeks with the two WTG configuration requiring additional time in order to permit relocation of cranes equipment. This includes:

- Three days for equipment offload and preassembly.
- Four days for tower installation.
- One day for nacelle lift and installation.
- Two days for rotor pre-assembly.
- One day for rotor lift.
- Three days for down-tower wiring.
The work for the erection period has been scheduled for summer to limit the risk of down days related to weather events (cold temperatures, adverse conditions, high winds). Should the construction schedule shift and cause the lift and installation to happen in the winter months, then the erection is likely to require more time and would also run a greater risk of facing weather delays. However, the schedule as currently envisioned would offer the option of moving the erection to winter and achieve an earlier COD. If that option was selected, the erection of the WTG(s) would take place in mid-February 2019 contingent on equipment being shipped and stored at the Inuvik Port (see Section 7.2). This would advance the COD date by five months; however it would also incur additional construction and storage costs. All this would need to be accounted for to determine whether this should be the preferred path forward.

7.2 Logistical Considerations

Logistical challenges to the project arise from two primary and interrelated issues: the fact that this is a small, remote project, and the fact that is in a northern climate. These will affect both equipment transport and construction.

7.2.1 Equipment Transport

The first consequence of these challenges relates to large equipment transportation. WTG components can be transported several different ways, including road, rail, and barge. All of these may be used at various stages for the Project depending on final WTG manufacturer selection and their manufacturing/assembly locations.

Typically, WTG manufacturers negotiate the transfer of equipment ownership and the associated liability of WTG components with project owners. Most commonly the transfer location is at the Project site; in the current case and given the Project’s remote location this may not be possible. Consequently this will require additional interfaces in the transport of equipment which will need to be appropriately managed. Large loads for WTG components are common with the following transport requirements being typical:

- WTG blades with length of between 29 to 65 m in length, 11 – 17 tonnes.
- WTG nacelle between 55 and 115 tonnes depending on type and assembly during transport (i.e. whether shipped assembled with the generator and gearbox).
- WTG tower sections: varying but up to approximately 30 m in length, 60 tonnes in weight and approximately 4.5 m in diameter.

Note that the weights above are per component and not gross vehicle weights. Consequently, there are two envisioned transport scenarios for the Project:

- Overland travel from British Columbia, via the Yukon, and to Inuvik.
- Mixed mode transport via Alberta and the NWT where the components are barged via Hay Port to Inuvik.

Assuming a common starting point for transport in Edmonton, Alberta, road transportation would require roughly 3,200 km of travel via road. Major challenges are unlikely throughout Alberta and British Columbia. Issues may arise during long stretches in the Yukon or NWT where services stations are limited or where infrastructure was not designed for heavy or large loads.
Load restrictions associated with Yukon Hwy 1 and 2 would limit the ability to transport heavy loads in the Yukon and NWT during spring (March-April). The Dempster Highway (Yukon Hwy 5, NWT Hwy 8) also includes weight restrictions of up to 63.5 tonnes gross vehicle weight; it is likely that some loads will be heavier than this limit. Additionally, two ferry crossings would need to be made with the WTG components in the NWT near Fort McPherson and Tsiigehtchic if transport of components occurs between June and October. It has not been determined whether ferries or barges capable of handling the oversized loads exist at these location. It may be that during deep winter (December – February) the river crossings may allow heavy traffic. Consequently, overland travel is not expected to be the preferred option for the Project, however winter transport of equipment may be viable provided that permission is received from the various territorial and provincial governments for heavy loads and if the ice road crossings can handle the heavy loads.

Transportation of equipment by truck or rail from Edmonton to Hay River followed by barge to Inuvik may be a viable option for component transport. This route is only passable in the summer time (June to August) when the Mackenzie is ice free. SgurrEnergy understands that the Northern Transportation Company Ltd. which operated barging operations on the Mackenzie prior to its bankruptcy, was purchased by the Government of the Northwest Territories. This being the case, the Client may be in the best position to identify if and when these operations will resume and what the potential costs associated with barge operations may be.

An alternative approach to allow winter construction would be to transport and store WTG components at the Inuvik port. This would increase project costs but should this permit an earlier COD then the increased costs may be fully if not partially, offset by energy sales from the Project. It should be noted however that transport contacts via barge must be confirmed six months in advance.

Estimated transportation costs from western Canada to the Inuvik are provided in Table 7-1 below.

Table 7-1: Estimated Transport Costs (Source: Logisiticus)

<table>
<thead>
<tr>
<th>WTG Platform</th>
<th>Truck from POI to Site</th>
<th>Truck to Hay River / Barge to Inuvik</th>
</tr>
</thead>
<tbody>
<tr>
<td>GE</td>
<td>$1,149,250</td>
<td>$1,202,333</td>
</tr>
<tr>
<td>Enercon</td>
<td>$1,477,300</td>
<td>$1,562,200</td>
</tr>
<tr>
<td>EWT*</td>
<td>$837,000</td>
<td>$846,800</td>
</tr>
</tbody>
</table>

*Quoted for 2 WTGs. The price is scaled to be used in the Project’s financial model (Section 8)

The decision on the preferred transport route will depend on final WTG selection, planned construction schedule, and the findings of the transportation study. As of the time of writing, SgurrEnergy expects a rail and barge transport system to be best option for the Project as it negates storage requirements. This is based on the assumption that barging operations on the Mackenzie resume in 2018 or 2019.

7.2.2 Sources of Granular Fill

There are two quarries near the proposed site. The closest quarry is located at km 251 along the Dempster Highway, approximately 4km to the south-east of the proposed site access road. A second quarry located to
the west of the airport is approximately 6.5 km from the proposed site access road and 1.5 km from the proposed interconnection point. Based on IEL discussions with local operators, the estimated cost of granular fill is $60/m³.

Figure 7-2: Airport quarry

Figure 7-3: KM251 Quarry
### 7.2.3 Construction Logistics

Logistical challenges for the project are generally related to the Project’s remote location and size. The issues resulting from these challenges can be simplified by adequate construction scheduling. Key construction constraints are listed below.

#### Table 7-2: Construction Logistical Challenges

<table>
<thead>
<tr>
<th>Logistical Challenge</th>
<th>Potential Solution and Net Impact.</th>
</tr>
</thead>
</table>
| Limited or inexistent passing ability on the access road from the Dempster Highway to site | 1. Large equipment would need to be delivered and unloaded one trip at a time.  
2. Daily scheduling would be required to manage site ingress and egress.  
3. Trucks may need to back out from the site all the way to the highway.  
Net impact: increased cost during transport and mobilization times offset by anticipated savings in larger road construction costs. |
| High slopes on roadway required in order to limit use of embankment fill.            | 1. Where slopes exceed the 10% grade a tow vehicle will be needed to help oversized deliveries access the site.  
2. The rate of change of the road gradient will need to be appropriately designed in order to ensure that no oversized loads bottom out when entering or cresting gradients along the road.  
Net impact: additional construction equipment will be needed on site and additional time will be required for equipment deliveries though the additional cost is anticipated to be less than that for additional fill to reduce road gradients. |
| Winter civil works                                                                   | 1. Use of northern contractors where possible.  
2. Contingency scheduling to allow for weather delays and reduced pace of work.  
3. Use of artificial lighting to allow continued construction works as needed.  
Net impact: Longer than average construction schedule offset but reduced risk of cost overruns due to delays particularly during erection of the WTG(s). |
| Permafrost foundation conditions resulting in a non-standard WTG base.                | 1. Use of prefabricated steel or concrete platform to avoid winter or site concreting activities (see Section 5.3.2).  
Net impact: increased cost and assembly time for the Project but avoidance of permafrost impacts and winter concreting. |
| Limited availability of construction staging and adaptation of construction works due to delays | 1. Regular communication and close monitoring of construction contractors.  
2. Contingency buffer included in Project schedule to allow for potential delays without overall impact on the Project schedule and costs.  
Net impact: longer than typical construction schedule in order to avoid cost associated with extra mobilization, demobilization or down days where work for a previous task cannot be completed as planned. |
7.3 Construction Schedule and Logistics Conclusions

Site specific constraints are associated with the proposed size and location of the Project and these must be carefully accounted for in the early planning and design stages.

Construction of the Project is expected to take 15 months starting in April 2018. While the construction schedule is considered very long for a Project of this capacity, it is dictated by local site conditions. The timeline for building the road is the main driver for the Project schedule as it will be the most time consuming activity. Consequently most of the Project construction staging is sequential with the exception of much of the electrical installation and upgrade works which can be performed in parallel with as road construction.

The Project will require a detailed transportation study once the preferred WTG technology is confirmed and initial negotiations with the WTG manufacturers have taken place. This will better qualify the logistical challenges and costs of WTG transportation. At this stage it is assumed that bargeing components via the Mackenzie River will be the most cost effective transport solution provided that the GNWT re-initiates bargeing activities from Hay River to Inuvik in time for the Project.

Construction challenges are related to the scale, timing, and location of the Project and can be mitigated by the use of experienced contractors and a long construction schedule that includes buffers. This may lead to higher initial construction and CAPEX costs but will result in greater certainty for the Project and less risk of unexpected costs due to construction delays.

Ultimately, while there are complexities related associated with the Project, none of the construction or logistical challenges encountered cannot be addressed using good development and design practices, construction management, and contingency planning.
8 Preliminary Financial Analysis

SgurrEnergy has created a preliminary financial model in order to compare the various scenarios discussed in Section 4.5. The model inputs are based on details provided by the Client, quotations provided by potential equipment suppliers and service providers, and estimates based on SgurrEnergy experience.

In this section, the key inputs and outputs in terms of capital expenditure (Capex), operational expenditure (Opex) as well as revenue and avoided costs are discussed.

8.1 Financial Assumptions

The model assumes a 15 year project life. Although 20 years is the typical accepted design life of modern WTGs and is widely used in financial models for wind farms, SgurrEnergy assumes a 15 year project life to account for challenging site conditions which are likely to cause premature wear of the WTG(s). It should be noted that the 15 year life is a conservative working assumption that adversely impacts the Project economics; the effective LCOE for the Project would come down should the turbine effectively survive for 20 years or more.

The Weighted Average Cost of Capital (WACC) value of 4.91% to be used for the Project was provided by the Client, and is included in the model as the discount rate.

8.2 Capex

The Capex for the project is the initial investment made at the site for new equipment, plus all temporary expenditure associated with development and construction of the project. Specifically:

- The new generating assets, i.e. WTG and battery energy storage system.
- All associated design, transportation, installation, and integration work (and potentially the training of local technicians) provided by third-party suppliers.
- Foundations and other non-generating components of the Project, such as access roads and collector lines (civil and electrical BoP).
- Development expenditures made by the client to date and those expected in the future.
- Contingency.

No land acquisition or leasing cost has been assumed; rather it is expected that the land will be granted to the Project at no or nominal cost.

8.3 Capex Scenarios

The overall project economics are strongly influenced by the Capex, which is largely driven by the costs of the WTG(s), construction of the access road, and the powerline connecting the Project site to the Inuvik Airport.

Table 8-1 below shows a summary of the different Capex breakdown of the three major groups of scenarios set up for different WTGs. Within each group the impacts on project economics by employing different ESS products are discussed in Section 8.4 and 8.5.
Table 8-1: Capex Costs for Various Configurations

<table>
<thead>
<tr>
<th>Capex</th>
<th>4 x EWT DW-61</th>
<th>Enercon E-103 2.35MW</th>
<th>GE 3.8M130</th>
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<tbody>
<tr>
<td>WTG Cost</td>
<td>$6,967,000</td>
<td>$2,750,000</td>
<td>$4,643,000</td>
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<tr>
<td>WTG Delivery to Site</td>
<td>$1,694,000</td>
<td>$1,563,000</td>
<td>$1,203,000</td>
</tr>
<tr>
<td>WTG Installation</td>
<td>$1,205,000</td>
<td>$1,014,000</td>
<td>$1,038,000</td>
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<tr>
<td>WTG Foundation</td>
<td>$1,013,000</td>
<td>$450,000</td>
<td>$450,000</td>
</tr>
<tr>
<td>ESS*</td>
<td>$1,290,000</td>
<td>$1,962,000</td>
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<td>Road</td>
<td>$6,600,000</td>
<td>$5,141,000</td>
<td>$5,141,000</td>
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<tr>
<td>Electrical</td>
<td>$4,248,000</td>
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<tr>
<td>Development Costs**</td>
<td>$942,000</td>
<td>$942,000</td>
<td>$942,000</td>
</tr>
<tr>
<td>Subtotal*</td>
<td>$23,959,000</td>
<td>$17,620,000</td>
<td>$18,281,000</td>
</tr>
<tr>
<td>Contingency (20% of total minus WTG cost and delivery)</td>
<td>$2,300,000</td>
<td>$2,000,000</td>
<td>$1,870,000</td>
</tr>
<tr>
<td>Total*</td>
<td>$26,259,000</td>
<td>$19,620,000</td>
<td>$20,151,000</td>
</tr>
<tr>
<td>LCOE (/kWh)*</td>
<td>$0.26</td>
<td>$0.26</td>
<td>$0.18</td>
</tr>
</tbody>
</table>

*Approximate costs depending on the ESS selected, however there is little cost variation between the different options within each configuration.

** Development costs include permits, EA, detailed engineering, topo and surveys, due diligence and geotech and represent average values based on normal developer process.

8.4 Opex

After the Capex has been spent and the Project is commissioned, additional funds must be allocated every year for the duration of the Project life to cover operations and maintenance of the WTG and ESS. Renewable energy projects are typically financially front heavy, meaning that they require a large investment up-front but little additional spending over their lifetime.

SgurrEnergy has based our Opex assumptions on some limited estimates from suppliers, and our own experience of wind farm operation and maintenance budgets.
Table 8-2: Opex Costs for Project

<table>
<thead>
<tr>
<th>Category</th>
<th>Value (or lifetime range) per year</th>
<th>Comment</th>
</tr>
</thead>
<tbody>
<tr>
<td>WTG maintenance</td>
<td>$65,000 to $100,000, ranging over the project lifetime</td>
<td>This is at the high end of SgurrEnergy experience, reflecting the site conditions.</td>
</tr>
<tr>
<td>ESS maintenance</td>
<td>$10,000 with an additional $15,000 every five years.</td>
<td>ESS are designed to require very limited maintenance.</td>
</tr>
<tr>
<td>Civil BoP maintenance</td>
<td>$24,500</td>
<td>Based on 5,000 per km of road, and an estimate of 4.85 km roads.</td>
</tr>
<tr>
<td>Electrical BOP maintenance</td>
<td>$25,000</td>
<td>Based on 2,500 per km of collector line an estimate of 10 km collector line.</td>
</tr>
<tr>
<td>Consultants</td>
<td>$10,000</td>
<td>Additional environmental and engineering specialists to be contracted as required.</td>
</tr>
<tr>
<td>Insurance</td>
<td>0.25% of capex</td>
<td>Estimated based on SgurrEnergy experience and industry average.</td>
</tr>
<tr>
<td>Operator wages</td>
<td>$150,000</td>
<td>On top of current operator wages. Estimated and can be updated if NTPC provides the current rates of labour.</td>
</tr>
<tr>
<td>Contingency</td>
<td>10% of other Opex</td>
<td>Based on SgurrEnergy experience.</td>
</tr>
</tbody>
</table>

The total base case Opex assumption is in the region of $355,000 per year initially, increasing gradually over the project lifetime as components age and require more maintenance.

8.5 Benefits ("Revenue")

The Project is not intended to generate revenue in terms of new additional cashflow to the Project owner. Instead it is aimed at adding renewable energy to the current electricity supply mix and reducing the use of the existing diesel generators, which indirectly yields the following two financial benefits:

- Reduced fossil fuel consumption.
- Less frequent and delayed maintenance activities and overhauls of the existing generators due to a reduced number of run hours every year.
To quantify these two benefits, SgurrEnergy has used the inputs and made the assumptions outlined in this section.

8.5.1 Reduced Fuel Consumption

The two fuels currently used for electricity generation are diesel and LNG. The Client has indicated that the 2016 cost of each are $1.186 per liter and $24.16 per gigajoule respectively. At a conversion rate of 0.0353 gigajoules per cubic meter, the LNG has a cost of $0.853 per cubic meter.

For each scenario (different combinations of WTGs and ESS products), these unit costs are multiplied by the fuel consumptions estimated during system integration modelling (Section 4.5) and compared to the business-as-usual (BAU) case in order to derive the financial benefits.

8.5.2 Delayed Maintenance of Generators

As discussed in Section 4.2.3, the generator maintenance intervals and costs provided by the Client shows that as the generators age, the maintenance and overhaul costs can be considerable. For example, at the milestone of 24,000 operational hours (approximately 2.75 years), the overhauls required for the generators would cost between $400,000 and $700,000, with the natural gas generators at the high end.

Adding WTG(s) to the microgrid, especially two of the larger models considered (GE and Enercon) with appropriately sized ESSs would allow one of the generators to sometimes be turned off, especially during summer nights when the load is relatively low and the wind speed is relatively high. Based on the system performance time series simulated using HOMER, SgurrEnergy is able to estimate the generators’ annual operational hours, which are then combined with the maintenance interval and costs from Table 4-2 to derive the generators’ annual maintenance cost for each scenario. Finally, these costs are compared with the average annual maintenance and overhaul costs in the BAU case to calculate the maintenance cost “savings”.

8.6 Sensitivity Analysis

In order to evaluate the importance of several key variables in the financial results, a sensitivity analysis was performed. Some of the relationships identified are listed below.

- Capex to LCOE has a coefficient of 1; for a 10% or roughly $2M change in capex, there will be slightly less than 10% change in cost of energy (both up and down).
- Capex to benefit has a coefficient of -2; a 25% increase in capex, gives a 50% hit to net benefit.
- Opex to LCOE has a coefficient of -0.05; a 25% or $20,000 change in the amount of annual Opex results in 2% change to net benefit by means of altering the avoided generators’ maintenance costs, while the cost of energy is estimated to change by slightly less than 1%.
- Energy production to LCOE has a coefficient of -1; a 10% change in annual wind energy generation results in approximately 10% change on LCOE.
- Fuel cost to benefit has a coefficient of 3; a 10% change in flat lifetime fuel cost (diesel going from $1.186/L up to $1.245/L, for example) will lead to approximately 30% change in net benefit of the new renewables investment (both up and down).
8.7 Summary of Results

Table 8-3 shows a summary of the economics associated with selected illustrative scenario results. It shows a description of the components associated with each scenario, Capex and O&M costs and the total amount of energy produced by the WTG(s) in each case. The renewable penetration represents the proportion of total energy used that comes from renewable energy. The maximum wind penetration using Enercon E-103 2.35 MW is expected to be around 80% and is observed during summer nights.

The cost of renewable energy is the sum of the initial Capex and the lifetime discounted Opex, divided by the lifetime sum of energy generated. It can be interpreted as the cost of the power, or the price per kWh of energy generated from the WTG(s) to pay for the Opex and the initial Capex of the wind and storage related components in the system. This calculation does not take into account any avoided fuel or maintenance costs from using the existing diesel and natural gas generators, but rather exclusively evaluates the cost of power from the WTG-ESS system.

The system LCOE shows the resulting cost of energy at Inuvik community including the benefit of reduced fuel consumptions and the deferred maintenance activities and overhauls for the generators over the 15 years of project life. In several scenarios, the combined benefits outweigh the costs brought by the WTG-ESS system. In other words, the integrated system is able to “pay back” the initial capex using this “revenue”, and the cost of energy is potentially lower than the current level (the BAU case).

Figures are also provided for fuel consumption and savings compared to the base case on both the diesel and LNG fronts as well as the monetary value of the savings. The percentage number represents the fraction of each fuel type that is saved in each configuration. The bottom two lines show greenhouse gases (GHG) emissions and savings compared to the base case.

Figure 8-1 shows a visual summary of some of the key parameters of each scenario, namely fuel consumption, value of saved fuel and GHG emission reductions. Details of each scenario modeling is presented in Appendix C.
Table 8-3: Summary of Project Economics for Optimal Configurations

<table>
<thead>
<tr>
<th>Scenario</th>
<th>1</th>
<th>2</th>
<th>3</th>
<th>4</th>
<th>5</th>
<th>6</th>
<th>7</th>
</tr>
</thead>
<tbody>
<tr>
<td>WTG</td>
<td>BAU</td>
<td>4 x EWT DW-61</td>
<td>Enercon E-103 2.35 MW</td>
<td>GE 3.8-130</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>ESS</td>
<td>5 x SMS-250</td>
<td>2 x Y.Cube 250/2</td>
<td>8 x SMS-250</td>
<td>4 x Y.Cube 250/2</td>
<td>4 x SMS-250</td>
<td>4 x Saft IM 20P</td>
<td></td>
</tr>
<tr>
<td>Capex ($)</td>
<td>0</td>
<td>$26.3M</td>
<td>$26.0M</td>
<td>$19.6M</td>
<td>$19.5M</td>
<td>$20.1M</td>
<td>$19.9M</td>
</tr>
<tr>
<td>Fuel + O&amp;M/year ($)</td>
<td>$7.4M</td>
<td>$5.8M</td>
<td>$5.8M</td>
<td>$6.2M</td>
<td>$6.1M</td>
<td>$5.4M</td>
<td>$5.3M</td>
</tr>
<tr>
<td>Usable Renewable Energy (MWh)</td>
<td>N/A</td>
<td>7,434</td>
<td>5,782</td>
<td>8,730</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Renewable Penetration</td>
<td>0</td>
<td>24%</td>
<td>18%</td>
<td>28%</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Cost of RE ($/kWh)</td>
<td>N/A</td>
<td>0.27</td>
<td>0.26</td>
<td>0.26</td>
<td>0.26</td>
<td>0.18</td>
<td></td>
</tr>
<tr>
<td>System LCOE ($/kWh)</td>
<td>0.24</td>
<td>0.24</td>
<td>0.24</td>
<td>0.23</td>
<td>0.24</td>
<td>0.22</td>
<td>0.21</td>
</tr>
<tr>
<td>Fossil Fuel Used (1,000 L Diesel /1,000 m³ NG per Year)</td>
<td>5,048 / 3,760</td>
<td>3,914 / 2,763</td>
<td>4,121 / 2,570</td>
<td>3,867 / 3,268</td>
<td>4,003 / 3,125</td>
<td>3,199 / 3,072</td>
<td>2,557 / 3,690</td>
</tr>
<tr>
<td>Fossil Fuel Savings (1,000 L Diesel /1,000 m³ NG per Year)</td>
<td>0</td>
<td>1,228 / 882</td>
<td>927 / 1,191</td>
<td>1,181 / 493</td>
<td>1,046 / 636</td>
<td>1,850 / 689</td>
<td>2,492 / 70</td>
</tr>
<tr>
<td>Value of fossil fuel savings ($1,000/year)</td>
<td>0</td>
<td>1,462 / 750</td>
<td>1,103 / 1012</td>
<td>1,406 / 419</td>
<td>1,244 / 540</td>
<td>2,201 / 585</td>
<td>2,965 / 60</td>
</tr>
<tr>
<td>GHG emissions (Tonnes/Year)</td>
<td>23,042</td>
<td>17,504</td>
<td>17,713</td>
<td>18,498</td>
<td>18,583</td>
<td>16,108</td>
<td>15,577</td>
</tr>
<tr>
<td>GHG Savings (Tonnes/Year)</td>
<td>0</td>
<td>5,534</td>
<td>5,326</td>
<td>4,545</td>
<td>4,459</td>
<td>6,935</td>
<td>7,465</td>
</tr>
</tbody>
</table>

Notes:
- For all the cases over the Project lifetime, the annual electricity supply is assumed to be 31.5 GWh as discussed in Section 4.1.
- The system integration modelling shows that if an advanced microgrid controller is employed, the amount of excess electricity is negligible.
Figure 8-1: Comparison of Scenarios
8.8 Conclusions

A variety of configurations are possible for the proposed site and a large number of them were simulated and put into the financial model to obtain optimal results. Options were ranked according to the cost of power, quantity and value of fuel savings as well as GHG reductions.

It is the conclusion of the Project Team that the best scenario found is a single GE 3.85/130 with 4 x Saft batteries. It presents the best cost of energy at approximately $0.17/kWh, generates nearly $3M in fuel savings and eliminates over 7,000 tonnes of GHG emissions per year. Furthermore, the use of this battery over the S&C model allows virtually all of the fuel savings to be made on diesel as opposed to LNG. Under this configuration, the level of renewable energy penetration is 28% and the overall cost of energy at Inuvik is reduced from $0.24/kWh to $0.21/kWh.

Modeling performed using the Enercon 2.35 MW WTG and EWT 900 kW in conjunction with the SMS batteries also yielded favorable results, with the energy produced costing basically the same as the business as usual scenario. These configuration eliminate 4,500 tonnes of GHG emissions per year. While not as attractive as the GE 3.85 MW case, these results are encouraging because they confirm the existence of multiple acceptable WTG models for the site.

The sensitivity analysis showed that the key Project variables impacting LCOE and benefit are the initial Capex and the annual energy output of the WTG. The cost of fuel also has a strong impact on Project benefit but doesn’t affect LCOE.
9 Optimization Opportunities

Several working assumptions had to be established during the completion of the feasibility study to limit the scope of work. Some avenues for Project improvement have been found but not investigated in detail at this point. This section presents some of the most promising options for improving various aspects of the Project.

9.1 Alternate Turbine Location

The Project Team briefly reviewed the opportunity of moving the WTG to a different location in order to reduce the cost of the access road. While the turbine located next to the met tower is the one that produces the most energy, it also requires a 4 km long access road.

An alternate site has been identified for the Project. This site is located closer to the highway in an area of lower wind resource, but construction at this site would likely result in reduced civil costs. The difference in cost has not been quantified herein and while access would be roughly halved, the steep drop and climb to the site from the existing prospective road may result in no net savings due to high fill volumes. However, this does illustrate that there are a variety of locations in the area that may prove viable if optimizing against civil costs is studied in further detail.

The alternate location would be expected to generate up to 10% less energy than the main option, with the potential offsetting benefit of halving the road construction cost. See Figure 9-1 and Figure 9-2 for an overview of the proposed alternate location and associated wind resource.
Figure 9-1 : Project Overview Map Showing Alternate WTG Location
Figure 9-2: Project Overview Map Showing Wind Resource at Alternate WTG Location
9.2 Adding an Additional Turbine

The proposed system concept was for a single large WTG or several small ones to be added at Inuvik in order for the local grid to be able to absorb almost all of the energy generated. During the assembly of the feasibility study the Project Team realized that once the infrastructure was in place to allow the installation of a turbine on site, incremental costs for additional turbines would be very low. Since such a large proportion of the Capex comes from the BoP components, it might be beneficial to investigate a system where several WTGs are installed. Such a configuration would likely result in energy production higher than what the grid could absorb, but low incremental costs might make economic sense. Various uses could also be imagined for excess energy, including building and water heating.

9.3 Scaling Up the Storage and Using Diesel as Backup

Taking the concept from Section 9.2 further, the ESS could be scaled up to a level where it becomes grid forming. This would imply using the ESS as the central component supporting the Inuvik grid and represents a radical change from the current mode of operation where generators support the grid. Under this operational scheme, additional WTGs would be beneficial to inject significant renewable energy in the system, and generators are only fired up when the battery level becomes too low. While there are very few such grids operating under this configuration around the globe, the fossil fuel savings associated would be much higher, potentially ranging up to 90% of the current consumption.

The Project Team believes that while it would be premature to consider this approach at present, the opportunity could be revisited once a single WTG and ESS has been in successful operation at the site for some time.
10 Conclusion and Recommendations

The Government of Northwest Territories appointed the Project Team to conduct a feasibility assessment for the potential integration of wind generation and energy storage equipment into the existing electrical grid that serves the town of Inuvik located in the Northwest Territories, Canada.

This section summarizes findings and recommendations from the Project Team for the next steps in the Project.

Wind resource and energy generation

As part of the assessment process SgurrEnergy undertook a high-level analysis of the wind resource at the Project site. Wind data were collected from a single 60 m meteorological (met) mast at the Project site. The wind speed value measured by the heated sensor at 50 m was 6.12 m/s. A 15-year dataset from MERRA was used to establish long-term wind speed adjustments for the site mast. This process led to a -0.7% correction and an average long term wind speed of 6.08 m/s representing the estimated long-term average wind speed on site at 50 m above ground.

It should be noted that the short duration of the measured wind and weather data led to considerable uncertainty in the energy yield assessment. SgurrEnergy strongly suggests installing a met mast at least ¾ of the hub height proposed WTG(s) with heated instruments. The energy yield assessment shall be updated when a full year of data become available.

Based on the updated site and WTG information collected, individual manufacturer track record and WTG performance, SgurrEnergy recommends shortlisting turbines E103-2.35 MW from Enercon, 3.85 MW from GE and DW 61-900 kW from EWT for the Project.”

System integration

SgurrEnergy modeled the load and generation data from the current diesel and LNG generation plants as well as their interaction with the generation from a WTG located on site. The typical load at Inuvik peaks in winter at about 4.0 MW and load variations resemble the typical load fluctuations of a small residential community. The current fuel costs for annual generation in Inuvik is estimated at nearly $9 million dollars, a figure that is highly susceptible to variations in fuel prices. Based on preliminary modelling SgurrEnergy estimates that considerable financial and GHG savings can be achieved by the Project, ranging from $1.6 million in fuel savings and nearly 4,000 tonnes of GHG offset to nearly $3 million in fuel savings and 7,000 tonnes of GHG offset annually.

Considerable uncertainty remains in the fuel savings estimated due to a lack of data available for the analysis and limitations of software tools to take into account generator variations on a sub 10 minute time interval. SgurrEnergy recommends that the system integration and performance modelling be revisited during detailed system analysis should the Project move forward.

Electrical and civil design

Based on the information collected from site and exchanges with NTPC, no major hurdles have been identified on the electrical design side. A new 25 kV line of approximately 10 km will be required to interconnect the WTG to the airport substation. Upgrades will be required at the airport substation to connect the WTG, at the main powerhouse to connect the ESS, and potentially on some section of the
collection system. The estimated costs for new infrastructure as well as anticipated upgrades to the existing grid have been accounted for in the financial model. Further design work will be required at a later stage of the project, and more detailed requirements will be needed from NTPC as to how the process should take place.

The new road length to the project is expected to be 4.85 km with a maximum grade of 10%. This grade is slightly above the typical maximum grade permissible for the transport of large WTG components. However, travel on these grades should still be possible with the proper equipment. Grades may further be relaxed where necessary if a towing tractor is used to assist the transport of large equipment on steeper slopes. In this scenario, less fill may be necessary reducing road costs.

Several concepts are being considered for the turbine foundation depending on the actual subgrade conditions at the site. Further geotechnical investigation will be required to select the adequate design, but the Project Team considers that all cases are feasible.

The civil design component of the Project represents the single largest cost for development. Consequently, additional studies and geotechnical work could better quantify and qualify design options available for the Project and reduce overall costs. These studies would bring sizeable benefits in terms of reduced uncertainty with regards to the overall cost of development.

**Regulatory**

It is anticipated that the Project will undergo a preliminary screening, with the GLWB as the primary reviewing agency. It is Hemmera’s view that the Project is unlikely to be referred for environmental assessment as few items and effects are emerging as high-risk. Overall, environmental and community risks associated with the Projects are considered low. Effects to biological components were considered of moderate risk due to potential impacts to migratory birds during Project operations and potential direct and indirect impacts on boreal caribou. Additional understanding of these issues is recommended. Consultation with agencies and Aboriginal groups will be required to gain a better understanding of issues specific to the Project. Risks associated with permitting and tenuring are expected to be low.

**Construction Schedule and Logistics**

Site specific constraints are associated with the proposed size and location of the Project and these must be carefully accounted for in the early planning and design stages.

Construction of the Project is expected to take 15 months starting in April 2018. While the construction schedule is considered very long for a Project of this capacity, it is dictated by local site conditions. The timeline for building the road is the main driver for the Project schedule as it will be the most time consuming activity. Consequently most of the Project construction staging is sequential with the exception of much of the electrical installation and upgrade works which can be performed in parallel with as road construction.

The Project will require a detailed transportation study once the preferred WTG technology is confirmed and initial negotiations with the WTG manufacturers have taken place. This will better qualify the logistical challenges and costs of WTG transportation. At this stage it is assumed that barging components via the Mackenzie River will be the most cost effective transport solution provided that the GNWT re-initiates barging activities from Hay River to Inuvik in time for the Project.
Construction challenges are related to the scale, timing, and location of the Project and can be mitigated by the use of experienced contractors and a long construction schedule that includes buffers. This may lead to higher initial construction and CAPEX costs but will result in greater certainty for the Project and less risk of unexpected costs due to construction delays.

Ultimately, the Project is complex but none of the construction or logistical challenges encountered cannot be addressed using good development and design practices, construction management, and contingency planning.

**Financial**

A variety of configurations are possible for the proposed site and a large number of them were simulated and put into the financial model to obtain optimal results. Options were ranked according to the cost of power, quantity and value of fuel savings as well as GHG reductions.

It is the conclusion of the Project Team that the best scenario found is a single GE 3.8/130 with 4 x Saft batteries. It presents the best cost of energy at approximately $0.17/kWh, generates nearly $3M in fuel savings and eliminates over 7,000 tonnes of GHG emissions. Furthermore, the use of this battery over the S&C model allows virtually all of the fuel savings to be made on diesel as opposed to LNG. Under this configuration, the level of renewable energy penetration is 28% and the overall cost of energy at Inuvik is reduced from $0.24/kWh to $0.21/kWh.

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### Appendix A  National Snow and Ice Data Centre excerpt

**Table A-1: NSIDC borehole excerpt**

<table>
<thead>
<tr>
<th>Country BH ID</th>
<th>Borehole Name</th>
<th>Elevation (m)</th>
<th>BH (m)</th>
<th>Depth (m)</th>
<th>Class</th>
<th>PF Thickness (m)</th>
<th>MAGT (°C)</th>
<th>MAGT Depth (m)</th>
<th>MAGT Date/Period</th>
<th>Year Drilled</th>
<th>Comments</th>
</tr>
</thead>
<tbody>
<tr>
<td>CA 116</td>
<td>T5 upland</td>
<td>40</td>
<td>10</td>
<td>SH</td>
<td></td>
<td>-5.5</td>
<td>10.0</td>
<td></td>
<td>Aug 2007-08</td>
<td>2006</td>
<td>MAGT determined at deepest sensor (above zero annual amplitude)</td>
</tr>
<tr>
<td>CA 115</td>
<td>T4 upland</td>
<td>81</td>
<td>10</td>
<td>SH</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td>2006</td>
<td></td>
</tr>
<tr>
<td>CA 120</td>
<td>Norris Creek NC-01</td>
<td>23</td>
<td>8.75</td>
<td>SU</td>
<td>&gt;9</td>
<td>-4.7</td>
<td>8.8</td>
<td></td>
<td>Aug 2008-09</td>
<td>2007</td>
<td>MAGT is calculated for deepest sensor which is above the level of zero annual amplitude.</td>
</tr>
<tr>
<td>CA 121</td>
<td>Campbell Lake CaL-01</td>
<td>123</td>
<td>4.6</td>
<td>SU</td>
<td>&gt;4.6</td>
<td>-1.1</td>
<td>4.6</td>
<td></td>
<td>Aug 2008-09</td>
<td>2007</td>
<td>MAGT is calculated for deepest sensor which is above the level of zero annual amplitude.</td>
</tr>
<tr>
<td>CA 123</td>
<td>Campbell Lake CaL-03</td>
<td>123</td>
<td>3</td>
<td>SU</td>
<td>&gt;3</td>
<td>-2.4</td>
<td>3.0</td>
<td></td>
<td>Aug 2008-09</td>
<td>2007</td>
<td>MAGT is calculated for deepest sensor which is above the level of zero annual amplitude.</td>
</tr>
<tr>
<td>CA 122</td>
<td>Campbell Lake CaL-02</td>
<td>123</td>
<td>5</td>
<td>SU</td>
<td>&gt;5</td>
<td>-0.8</td>
<td>5.0</td>
<td></td>
<td>Aug 2008-09</td>
<td>2007</td>
<td>MAGT determined at sensor close to zero annual amplitude</td>
</tr>
<tr>
<td>CA 124</td>
<td>North Caribou Lake NCL-01</td>
<td>214</td>
<td>5</td>
<td>SU</td>
<td>&gt;5</td>
<td>-1.6</td>
<td>5.0</td>
<td></td>
<td>Aug 2008-09</td>
<td>2007</td>
<td>MAGT is calculated for deepest sensor which is above the level of zero annual amplitude.</td>
</tr>
</tbody>
</table>
Appendix B  Storage System Providers

B.1  S&C Batteries

S&C Electric Company is a global provider of equipment and services for electric power systems. S&C was founded in 1911 and has been a pioneer in the advanced energy storage market. They are considered a top provider of advanced energy storage solutions and have collaborated with many other industry leaders on market-leading projects.

The main specifications of the proposed S&C system include 104 kWh storage and a maximum of 260 kW discharge power. The components can be shipped separately in regular transport aircrafts. The combined unit has a -45 degrees minimum operating temperature.

Figure B-10-1: The S&C Power Storage Management System (source: S&C Electric)
B.2 Younicos

Younicos is a global energy storage provider headquartered in Germany and founded in 2009 which currently operates approximately 100 MW of energy storage projects across the globe. Younicos expanded their base of operating assets by 60 MWs through the purchase of bankrupt company Xtreme Power in 2014. Younicos is chemistry-agnostic and purchases based on the Project need. This provides flexibility in tailoring solutions to the local market and each business case. While the advanced energy storage market is still relatively young, Younicos is considered one of the top providers with a varied base of project types across different markets.

For this Project, Younicos proposed the Y.Cube system (Figure B-10-2), a containerized and configurable product that includes the battery block, system converter, and a smart control system.

![Figure B-10-2: Younicos Y-Cube System (source: Younicos)](image-url)
ABB is a global multidisciplinary industrial equipment and systems supplier. The company has demonstrated experience in supplying ESS to challenging environments. In 2014, they installed a flywheel based ESS to a 28 MW microgrid on Kodiak Island in Alaska. ABB started collaborating with battery supplier Samsung SDI in 2015 to target the growing global microgrid market. Currently ABB has not completed any ESS projects in Canada, but has indicated clear interests in Canadian market with an office set up in Toronto.

![Figure B-10-3: ABB Battery Solutions (source: ABB)](image_url)
B.4 Saft

Saft specializes in the design, development, and manufacturing of a wide range of batteries. A well-established company headquartered in France, Saft North America is based in Jacksonville, Florida in North America. Saft offers Intensium® Max, a series of ready-to-install containerized energy storage products designed for renewable energy integrated systems and grid management. Saft commits to customizing their products and training of local technicians to ensure smooth transition into and the operation of the new integrated system.

Figure B-10-4: Saft Intensium Max (source: Saft)
B.5 EnSync

EnSync Energy Systems provide power control, management, and energy storage solutions to a wide range of customers. Headquartered outside of Milwaukee, Wisconsin, EnSync owns several global subsidiaries. Their Agile Hybrid Storage System™ features EnSync’s flow battery based on Zinc Bromide flow chemistry that allows long duration and deep discharge, while integrated with Li-ion and other short-discharge, high-power batteries as complementary storage technology for balanced applications.

Figure B-10-5 EnSync's Agile Hybrid Series (source: EnSync)
Appendix C  Financial Model Overview
### Capex Scenario: Business-as-Usual

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<td>(10,274,938)</td>
<td>(9,777,938)</td>
<td>(10,792,938)</td>
<td>(9,478,938)</td>
<td>(10,511,938)</td>
<td>(10,001,938)</td>
<td>(11,060,938)</td>
<td>(10,749,938)</td>
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<td>(9,757,938)</td>
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<td>Development Capex</td>
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<tr>
<td><strong>Sum of discounted lifetime opex</strong></td>
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<tr>
<td><strong>BAU LCOE</strong></td>
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<td>31,500</td>
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#### Average of discounted lifetime opex

(7,438,658)
### Capex Scenario:

**WTG**
- 2 x EWT OW-61: $10,876,550
- 2 x EWT OW-65: $7,434/MWh

**Electrical BOP**
- Median EWT: $4,247,500

**Civil BOP**
- High: $6,000,000

**Development Capex**
- Base Case: $342,000

**Contingency**
- 20% of total minus WTG: $230,000

**Total Capex**: $26,255,500

### Yearly Summary

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<td>Discount Factor at WACC</td>
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<td>LCOE pure cost $/MWh</td>
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<td>LCOE with benefits $/MWh</td>
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<tr>
<td>Reduced OPEX &amp; Fuel cost</td>
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<td>$(7,063,627)</td>
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<td>$(6,697,627)</td>
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<td>Production (same as BAU)</td>
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<td>System LCOE</td>
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### Capex Scenario:

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<th>Scenario</th>
<th>WTG</th>
<th>4 x EWT-DW-61</th>
<th>7,434 MWh</th>
<th>ESS</th>
<th>2 x Y.Cube 250/4</th>
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<th>Median EWT</th>
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#### Yearly Avoided Cost

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#### Operating Costs (Opex)

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#### System LCOE

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#### Additional Renewables Opex

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#### System LCOE

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### Capex Scenario:

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<td>Civil BOP</td>
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<td>Development Capex</td>
<td>Base Case</td>
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<td>Contingency</td>
<td>20% of total minus WTG</td>
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### Avoided cost value ("revenue")

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<tr>
<td>Avoided cost value (&quot;revenue&quot;)</td>
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<tr>
<td>Discount Factor at WACC</td>
<td>4.91%</td>
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<td>∑ Pure Cost NPV</td>
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<td>NPV with Benefits</td>
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### Production degradation curve

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<td>Production (same as BAU)</td>
<td>86,736 MWh</td>
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### LCOE pure cost

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<tbody>
<tr>
<td>LCOE pure cost</td>
<td>$0.268/MWh</td>
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### System

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<td>Reduced Op+ Fuel cost</td>
<td>$0.268/MWh</td>
<td>positive means it pays for itself</td>
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### Additional Renewables Opex

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<td>Additional Renewables Opex</td>
<td>$0.268/MWh</td>
<td>positive means it pays for itself</td>
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### Additional Renewables Capex, plus discount

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<td>Additional Renewables Capex, plus discount</td>
<td>$0.268/MWh</td>
<td>positive means it pays for itself</td>
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### Production (same as BAU)

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### System LCOE

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<td>$0.268/MWh</td>
<td>positive means it pays for itself</td>
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### Capex Scenario:

#### WTG

- Enercon E-103 2.35 MW
- 5,775,440

#### ESS

- 4 Y.Cube 250/2
- 1,861,500

#### Civil BOP

- Median
- 5,140,200

#### Development Capex

- Base Case
- 942,000

- Contingency
  - 20% of total minus WTG cost and delivery
  - 200,000

#### Total Capex

- 19,516,640

### Revenue

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<tr>
<td>Avoided cost value (&quot;revenue&quot;)</td>
<td>1,891,244</td>
<td>1,921,244</td>
<td>2,501,244</td>
<td>1,966,244</td>
<td>1,497,244</td>
<td>1,973,244</td>
<td>2,428,244</td>
<td>3,428,244</td>
<td>539,244</td>
<td>1,306,244</td>
<td>1,522,244</td>
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### Opex

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<tbody>
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<td>Discount Factor at WACC</td>
<td>4.91%</td>
<td>1.00</td>
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<td>1.21</td>
<td>1.27</td>
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### Pure Cost NPV

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<tr>
<td>Production degradation curve</td>
<td>1.00</td>
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### LCOE pure cost

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</thead>
<tbody>
<tr>
<td>Production (same as BAU)</td>
<td>472,500</td>
<td>5,782</td>
<td>5,782</td>
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<td>5,782</td>
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### System LCOE

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<tbody>
<tr>
<td>Reduced Opex &amp; Fuel cost</td>
<td>(7,631,004)</td>
<td>(8,353,004)</td>
<td>(7,578,004)</td>
<td>(8,008,004)</td>
<td>(8,338,004)</td>
<td>(7,981,004)</td>
<td>(8,538,004)</td>
<td>(7,142,004)</td>
<td>(8,589,004)</td>
<td>(7,221,004)</td>
<td>(8,601,004)</td>
<td>(8,402,004)</td>
<td>(6,235,004)</td>
<td>(6,824,004)</td>
<td>(6,392,004)</td>
<td>(10,755,004)</td>
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<tr>
<td>Additional Renewables Opex</td>
<td>(311,902)</td>
<td>(313,057)</td>
<td>(314,197)</td>
<td>(312,843)</td>
<td>(338,995)</td>
<td>(325,152)</td>
<td>(326,316)</td>
<td>(335,735)</td>
<td>(339,277)</td>
<td>(349,545)</td>
<td>(352,743)</td>
<td>(351,948)</td>
<td>(368,159)</td>
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<tr>
<td>Production (same as BAU)</td>
<td>472,500</td>
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<td>System LCOE</td>
<td>(239.08)</td>
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## Capex Scenario:

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<tbody>
<tr>
<td><strong>WTG</strong></td>
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<tr>
<td>GE 3.8-130</td>
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<td>4 S&amp;C SMS-250</td>
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<td><strong>Electrical BOP</strong></td>
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<td><strong>Civil BOP</strong></td>
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<td><strong>Total Capex</strong></td>
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<td>Contingency</td>
<td>187,000</td>
<td>203,000</td>
<td>219,000</td>
<td>235,000</td>
<td>251,000</td>
<td>267,000</td>
<td>283,000</td>
<td>300,000</td>
<td>317,000</td>
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<td>370,000</td>
<td>388,000</td>
<td>406,000</td>
<td>424,000</td>
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### Avoided cost value ("revenue")

- 2016: 2,890,114
- 2017: 2,920,114
- 2018: 3,500,114
- 2019: 2,965,114
- 2020: 2,496,114
- 2021: 2,972,114
- 2022: 3,858,114
- 2023: 3,011,114
- 2024: 4,427,114
- 2025: 2,521,114
- 2026: 2,905,114
- 2027: 2,521,114
- 2028: 4,149,114
- 2029: 1,255,114

### Opex

- (2016): (319,253)
- (2017): (320,424)
- (2018): (321,601)
- (2019): (330,284)
- (2020): (346,473)
- (2021): (332,658)
- (2022): (343,326)
- (2023): (346,982)
- (2024): (357,289)
- (2025): (358,526)
- (2026): (359,769)
- (2027): (376,019)
- (2028): (357,289)
- (2029): (358,526)
- (2030): (376,019)
- (2031): (357,289)

### Discount Factor at WACC

- 2016: 4.91%
- 2017: 1.00
- 2018: 1.05
- 2019: 1.10
- 2020: 1.15
- 2021: 1.21
- 2022: 1.27
- 2023: 1.33
- 2024: 1.40
- 2025: 1.47
- 2026: 1.54
- 2027: 1.61
- 2028: 1.69
- 2029: 1.78
- 2030: 1.86
- 2031: 1.96

### Pure Cost NPV

- 2016: (23,875,901)
- 2017: (20,147,558)
- 2018: (319,253)
- 2019: (305,428)
- 2020: (292,202)
- 2021: (286,047)
- 2022: (286,024)
- 2023: (281,774)
- 2024: (250,423)
- 2025: (245,464)
- 2026: (234,402)
- 2027: (234,402)
- 2028: (217,714)
- 2029: (190,714)
- 2030: (182,349)
- 2031: (174,984)

### NPV with Benefits

- 2016: 8,844,856
- 2017: (20,147,558)
- 2018: (2,570,861)
- 2019: (2,478,019)
- 2020: (2,887,513)
- 2021: (2,634,830)
- 2022: (2,149,641)
- 2023: (2,639,446)
- 2024: (3,524,245)
- 2025: (2,667,789)
- 2026: (4,082,576)
- 2027: (1,177,357)
- 2028: (2,558,132)
- 2029: (2,163,826)
- 2030: (2,633,588)
- 2031: (3,789,345)

### Production degradation curve

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<td>LifeTime Wind production</td>
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### LCOE with Benefits

- 2016: 67.55
- 2017: (negative means you need a PPA this size to break even)
- 2018: positive means it pays for itself
- 2019: positive means it pays for itself
- 2020: positive means it pays for itself
- 2021: positive means it pays for itself
- 2022: positive means it pays for itself
- 2023: positive means it pays for itself
- 2024: positive means it pays for itself
- 2025: positive means it pays for itself
- 2026: positive means it pays for itself
- 2027: positive means it pays for itself
- 2028: positive means it pays for itself
- 2029: positive means it pays for itself
- 2030: positive means it pays for itself
- 2031: positive means it pays for itself

### System LCOE

- 2016: (217.43)
- 2017: (217.43)
- 2018: (217.43)
- 2019: (217.43)
- 2020: (217.43)
- 2021: (217.43)
- 2022: (217.43)
- 2023: (217.43)
- 2024: (217.43)
- 2025: (217.43)
- 2026: (217.43)
- 2027: (217.43)
- 2028: (217.43)
- 2029: (217.43)
- 2030: (217.43)
- 2031: (217.43)

### System LCDE

- 2016: (217.43)
### Capex Scenarios:

<table>
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<tr>
<th>Scenario</th>
<th>W/G</th>
<th>Electrical BOP</th>
<th>Civil BOP</th>
<th>Development Capex</th>
<th>Contingency</th>
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<tbody>
<tr>
<td>2</td>
<td>GE 3.6-130</td>
<td>727,669</td>
<td>3,797,500</td>
<td>5,140,200</td>
<td>242,000</td>
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<tr>
<td>3</td>
<td>GE 7-150</td>
<td>727,669</td>
<td>3,797,500</td>
<td>5,140,200</td>
<td>242,000</td>
</tr>
</tbody>
</table>

#### WTG Costs

- **GE 3.8-130**
  - **Inst. Cost**: 3,732,298
  - **MWh**: 8,730

#### ESS Costs

- **4 Saft Intensium Max 20P**
  - **Inst. Cost**: 727,669

#### BOP Costs

- **Median**
  - **Electrical BOP**: 3,797,500
  - **Civil BOP**: 5,140,200

#### Development Capex

- **Base Case**: 242,000

#### Contingency

- **20% of total minus WTG**: 187,000

### Total Capex

- **19,809,666**

#### Yearly Breakdown

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<tr>
<td>Cost</td>
<td>3,124,014</td>
<td>3,141,014</td>
<td>3,725,014</td>
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<td>3,031,014</td>
<td>3,343,014</td>
<td>4,814,014</td>
<td>1,768,014</td>
<td>1,777,014</td>
<td>3,825,014</td>
<td>3,321,014</td>
<td>2,755,014</td>
<td>2,888,014</td>
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<tr>
<td>WACC</td>
<td>4.91%</td>
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<td>1.27</td>
<td>1.33</td>
<td>1.40</td>
<td>1.47</td>
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<td>1.61</td>
<td>1.69</td>
<td>1.78</td>
<td>1.86</td>
<td>1.96</td>
</tr>
<tr>
<td>NPV with Benefits</td>
<td>$11,354,527</td>
<td>(19,809,666)</td>
<td>2,805,135</td>
<td>2,688,938</td>
<td>3,092,637</td>
<td>2,473,569</td>
<td>1,977,078</td>
<td>2,123,610</td>
<td>2,729,133</td>
<td>2,144,933</td>
<td>3,049,205</td>
<td>2,846,955</td>
<td>1,665,910</td>
<td>1,284,702</td>
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#### Lifetime Wind Production

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<td>8,730</td>
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<td>8,730</td>
<td>8,730</td>
<td>8,730</td>
<td>8,730</td>
<td>8,730</td>
</tr>
</tbody>
</table>

### LCOE Breakdown

#### LCOE pure cost

- **$/MWh**: (179.72)
- **Negative means you need a PPA this size to break even**

#### LCOE with benefits

- **$/MWh**: 86.71
- **Positive means it pays for itself**

### System

#### Reduced Opex & Fuel cost

- **Lessed Opex**: (6,783,803)
- **Fuel cost**: (6,783,803)

#### Additional Renewables Opex

- **Lessed Opex**: (318,879)
- **Fuel cost**: (318,879)

#### Additional Renewables Capex, plus discount

- **Installed cost**: (100,225,346)
- **Discounted**: (25,533,789)

#### Production (same as BAU)

- **MWh**: 472,500

### Production 11-22

- **$/MWh**: 212.12

---

6.16.11251.MON.R.001

Revision B2

Appendix C  Page 7 of 7
Appendix D  Proposed Electrical Interconnection for WTG and ESS
Appendix E  Access Road Plan, Profile and Cross-section
HIGH POINT WIND
PROPOSED ACCESS ROAD
PLAN AND PROFILE

Legend
- Plan L-line Location
- Profile Subgrade
- Plan P-line Location
- Profile Stripped Surface
- Plan Slope Stakes
- Culverts
- Plan Road Edges
- Bridge Abutments
- Profile Topo

Curve Table

<table>
<thead>
<tr>
<th>Radius</th>
<th>Cut Dp.</th>
<th>Strip V.</th>
<th>SG Cut V.</th>
<th>SG Fill V.</th>
<th>Mass H.</th>
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Pg. Tot. | 0.0 | 14.0 | 4485.1
Cum. Tot. | 0.0 | 14.0 | 4485.1

OPTION 2
6 METER ROAD SURFACE
1.3:1 SIDE SLOPE
MAX. GRADE 10%

NOT FOR CONSTRUCTION

Field Surveyor : CW
Road Designer : NB
Approved By: NB

Plan Scale : 1:2000
Profile Vert Scale : 1:200
Profile Horz Scale : 1:2000
HIGH POINT WIND
PROPOSED ACCESS ROAD
PLAN AND PROFILE

Legend

- Plan L-line Location
- Profile Subgrade
- Plan P-line Location
- Profile Stripped Surface
- Plan Slope Stakes
- Culverts
- Plan Road Edges
- Bridge Abutments

Plan Scale 1:200
Profile Vert Scale 1:200
Profile Horz Scale 1:2000

Curve Table

<table>
<thead>
<tr>
<th>Radius</th>
<th>Cut Dp.</th>
<th>Strip V.</th>
<th>SG Cut V.</th>
<th>SG Fill V.</th>
<th>Mass H.</th>
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Cum. Tot. 0.0 14.0 8341.2
Pg. Tot. 0.0 0.0 3856.1

CL Elkev
99.7
99.1
99.1
99.3
100.2
100.0
100.6
101.8

Gnd Elev
98.4
97.9
97.9
98.1
98.0
100.2
100.6
101.8

OPTION 2
6 METER ROAD SURFACE
1.3:1 SIDE SLOPE
MAX. GRADE 10%

NOT FOR CONSTRUCTION

Field Surveyor: CW
Road Designer: NB
Approved By: NB

Plan Scale 1:2000
Profile Vert Scale 1:200
Profile Horz Scale 1:2000
HIGH POINT WIND
PROPOSED ACCESS ROAD
PLAN AND PROFILE

Legend

<table>
<thead>
<tr>
<th>Plan L-line Location</th>
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<tr>
<td>Plan P-line Location</td>
<td>Profile Stripped Surface</td>
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<tr>
<td>Plan Slope Stakes</td>
<td>Culverts</td>
</tr>
<tr>
<td>Plan Road Edges</td>
<td>Bridge Abutments</td>
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<table>
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<th>L-Stn</th>
<th>Cut Dp.</th>
<th>Strip V.</th>
<th>SG Cut V.</th>
<th>SG Fill V.</th>
<th>Mass H.</th>
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<tbody>
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<td>-9891.2</td>
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<td>715.3</td>
<td>-10571.4</td>
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<td>0.0</td>
<td>0.0</td>
<td>715.3</td>
<td>-11322.5</td>
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<td>0.0</td>
<td>715.3</td>
<td>-12037.8</td>
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Cum. Tot. | 0.0 | 14.0 | 12051.8
Pg. Tot. | 0.0 | 0.0 | 3710.6

Curve Table

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Legend
- Plan L-line Location
- Profile Subgrade
- Profile Stripped Surface
- Plan Slope Stakes
- Culverts
- Plan Road Edges
- Bridge Abutments

Field Surveyor: CW
Road Designer: NB
Approved By: NB
Plan Scale: 1:2000
Profile Vert Scale: 1:200
Profile Horz Scale: 1:2000

OPTION 2
6 METER ROAD SURFACE
1.3:1 SIDE SLOPE
MAX. GRADE 10%

NOT FOR CONSTRUCTION
HIGH POINT WIND
PROPOSED ACCESS ROAD
PLAN AND PROFILE

Legend
- Plan L-line Location
- Profile Subgrade
- Plan P-line Location
- Profile Stripped Surface
- Plan Slope Stakes
- Culverts
- Plan Road Edges
- Bridge Abutments

Profile Vert Scale 1:200
Profile Horz Scale 1:2000
Plan Scale 1:2000

Approved By: L-Stn
Cut Dp. m.
Strip V. m.
SG Cut V. Cu. m.
SG Fill V. Cu. m.
Mass H. Cu. m.

<table>
<thead>
<tr>
<th>L-Stn</th>
<th>Cut Dp. m</th>
<th>Strip V. Cu. m</th>
<th>SG Cut V. Cu. m</th>
<th>SG Fill V. Cu. m</th>
<th>Mass H. Cu. m</th>
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Cum. Tot. 0.0 14.0 80632.5
Pg. Tot. 0.0 0.0 36724.5

Curve Table

Radius
Angle
Arc Len.

Field Surveyor : CW
Road Designer : NB
Approved By: NB

NOT FOR CONSTRUCTION
HIGH POINT WIND
PROPOSED ACCESS ROAD
CROSS SECTIONS

Legend

- L-line Location
- Topo
- Pavement (layer three)
- Sub horizon 2 (FR)
- Template
- Stripped Surface
- Subgrade Fill
- Culverts
- P-line Location

Curve Table

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<th>Cut Dp. (m)</th>
<th>L-Stn (m)</th>
<th>Strip V. (Cu. m)</th>
<th>SG Cut V. (Cu. m)</th>
<th>SG Fill V. (Cu. m)</th>
<th>Mass H. (Cu. m)</th>
</tr>
</thead>
<tbody>
<tr>
<td>200.0</td>
<td>-1.3</td>
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<td>0.0</td>
<td>877.1</td>
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<td>591.9</td>
<td>-3041.8</td>
<td></td>
</tr>
<tr>
<td>400.0</td>
<td>-1.2</td>
<td>0.0</td>
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</tr>
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OPTION 2
6 METER ROAD SURFACE
1.3:1 SIDE SLOPE
MAX. GRADE 10%

NOT FOR CONSTRUCTION

Field Surveyor: CW
Road Designer: NB
Approved By: XXXXX

Section Scale 1:200
HIGH POINT WIND
PROPOSED ACCESS ROAD
CROSS SECTIONS

Legend
- L-line Location
- Topo
- Pavement (layer three)
- Sub horizon 2 (FR)
- Template
- Subgrade fill
- Stripped surface
- Culverts
- P-line Location

Curved Table

600.0 | -1.2 | 0.0 | 743.8 | -5287.1
700.0 | -1.2 | 0.0 | 768.6 | -6030.9
800.0 | -1.2 | 0.0 | 741.8 | -6799.5
900.0 | -1.2 | 0.0 | 7555.3 | 2284.2

Pg. Tot. | 0.0 | 0.0 | 2284.2
Cum. Tot. | 0.0 | 14.9 | 7555.3

Field Surveyor: CW
Road Designer: NB
Approved By: XXXXX

OPTION 2
6 METER ROAD SURFACE
1.3:1 SIDE SLOPE
MAX. GRADE 10%

NOT FOR CONSTRUCTION

Section Scale: 1:200
HIGH POINT WIND
PROPOSED ACCESS ROAD
CROSS SECTIONS

Legend

- L-line Location
- Topo
- Pavement (layer three)
- Sub horizon 2 (FR)
- Template
- Stripped Surface
- Subgrade Fill
- Culverts
- P-line Location

Curve Table

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<th>Cut Dp m</th>
<th>Strip V Cu.m</th>
<th>SG Cut V Cu.m</th>
<th>SG Fill V Cu.m</th>
<th>Mass H Cu.m</th>
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</thead>
<tbody>
<tr>
<td>900.0</td>
<td>-1.2</td>
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<td>0.0</td>
<td>798.9</td>
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</tr>
</tbody>
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OPTION 2
6 METER ROAD SURFACE
1.3:1 SIDE SLOPE
MAX. GRADE 10%

NOT FOR CONSTRUCTION

Field Surveyor: CW
Road Designer: NB
Approved By: XXXXX

Section Scale 1:200
HIGH POINT WIND
PROPOSED ACCESS ROAD
CROSS SECTIONS

Legend

L-line Location
P-line Location
Topo
Sub horizon 2 (FR)
Template
Stripped Surface
Subgrade Fill
Culverts

Curve Table

Radius
Angle
Arc. Len.

<table>
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<tr>
<th>L-Stn</th>
<th>Cut Dp.</th>
<th>Strip V.</th>
<th>SG Cut V.</th>
<th>SG Fill V.</th>
<th>Mass H.</th>
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<td>1400.0</td>
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<td>0.0</td>
<td>0.0</td>
<td>715.3</td>
<td>-11322.5</td>
</tr>
<tr>
<td>1500.0</td>
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<td>0.0</td>
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Pg. Tot. 0.0 0.0 2146.6
Cum. Tot. 0.0 14.0 12651.8

OPTION 2
6 METER ROAD SURFACE
1.3:1 SIDE SLOPE
MAX. GRADE 10%

NOT FOR CONSTRUCTION

Field Surveyor: CW
Road Designer: NB
Approved By: XXXXX

Section Scale 1:200
HIGH POINT WIND
PROPOSED ACCESS ROAD
CROSS SECTIONS

Legend
- L-line Location
- Topo
- Pavement (layer three)
- Sub horizon 2 (FR)
- Template
- Stripped Surface
- Subgrade Fill
- Culverts
- P-line Location

Curve Table

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<th>m.</th>
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<th>Cu. m.</th>
<th>SG Cut V.</th>
<th>Cu. m.</th>
<th>SG Fill V.</th>
<th>Cu. m.</th>
<th>Mass H.</th>
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NOT FOR CONSTRUCTION

OPTION 2
6 METER ROAD SURFACE
1.3:1 SIDE SLOPE
MAX. GRADE 10%

Approved By: XXXXX

Field Surveyor: CW
Road Designer: NB
Section Scale: 1:200
HIGH POINT WIND
PROPOSED ACCESS ROAD
CROSS SECTIONS

Legend

L-line Location
P-line Location
Topo
Sub horizon 2 (FR)
Template
Stripped Surface
Subgrade fill
Culverts

Curve Table

Radius
Angle
Av. Len.

L-Stn
Cut Dp.
F Slope L:
F Slope R:
Super L:
Super R:
Cut V.
Strip V.
SG Cut V.
SG Fill V.
Mass H.

<table>
<thead>
<tr>
<th>L-Stn m</th>
<th>Cut Dp. m</th>
<th>Strip V. Cu. m</th>
<th>SG Cut V. Cu. m</th>
<th>SG Fill V. Cu. m</th>
<th>Mass H. Cu. m</th>
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Pg. Tot. 0.0 0.0 4813.4
Cum. Tot. 0.0 14.0 10179.0

OPTIO N 2
6 METER ROAD SURFACE
1.3:1 SIDE SLOPE
MAX. GRADE 10%

NOT FOR CONSTRUCTION

Field Surveyor: CW
Road Designer: NB
Approved By: XXXXX

Section Scale 1:200
### Curve Table

<table>
<thead>
<tr>
<th>L-Stn m</th>
<th>Cut Dp. m</th>
<th>Strip V. Cu. m</th>
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<th>SG Fill V. Cu. m</th>
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### Field Surveyor:
CW

### Road Designer:
NB

### Approved By:
XXXXX

### Section Scale:
1:200
HIGH POINT WIND
PROPOSED ACCESS ROAD
CROSS SECTIONS

OPTION 2
6 METER ROAD SURFACE
1.3:1 SIDE SLOPE
MAX. GRADE 10%

NOT FOR CONSTRUCTION

Field Surveyor: CW
Road Designer: NB
Approved By: XXXXXX

Section Scale 1:200
HIGH POINT WIND
PROPOSED ACCESS ROAD
CROSS SECTIONS

Legend

- L-line Location
- Topo
- Pavement (layer three)
- Sub horizon 2 (FR)
- Template
- Stripped Surface
- Culverts
- Subgrade fill

Curve Table

Radius
Angle
Arc. Len.

L-Stn
Cut Dp.
Strip V.
SG Cut V.
SG FILL V.
Mass H.

Cum. Tot.
Pg. Tot.

Field Surveyor: CW
Road Designer: NB
Approved By: XXXXX

Section Scale 1:200

OPTION 2
6 METER ROAD SURFACE
1.3:1 SIDE SLOPE
MAX. GRADE 10%

NOT FOR CONSTRUCTION
### Cross Sections

**Option 2**

**6 Meter Road Surface**

**1.3:1 Side Slope**

**Max. Grade 10%**

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**Approved By:** XXXXX

**Field Surveyor:** CW

**Road Designer:** NB

Section Scale 1:200
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**Field Surveyor:** CW  
**Road Designer:** NB  
**Approved By:** XXXXX  

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**OPTION 2**  
6 METER ROAD SURFACE  
1.3:1 SIDE SLOPE  
MAX. GRADE 10%  

**NOT FOR CONSTRUCTION**  
Section Scale 1:200
**HIGH POINT WIND**

**PROPOSED ACCESS ROAD**

**CROSS SECTIONS**

**OPTION 2**

6 METER ROAD SURFACE

1.3:1 SIDE SLOPE

MAX. GRADE 10%

---

**NOT FOR CONSTRUCTION**

---

**Legend**

- **L-line Location**
- **Topo**
- **Pavement (layer three)**
- **Sub horizon 2 (FR)**
- **Template**
- **Stripped Surface**
- **Subgrade Fill**
- **Culverts**

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**Approved By:** XXXXX

**Section Scale:** 1:200
HIGH POINT WIND
PROPOSED ACCESS ROAD
CROSS SECTIONS

Legend
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- Topo
- Pavement (layer three)
- Template
- Sub horizon 2 (FR)
- Stripped Surface
- Culverts
- Subgrade Fill
- P-line Location

Curve Table

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Cum. Tot. 0.0  14.0  84610.2

Field Surveyor: CW
Road Designer: NB
Approved By: XXXX

NOT FOR CONSTRUCTION

Section Scale 1:200
### Option 2

**6 Meter Road Surface**

**1.3:1 Side Slope**

**Max. Grade 10%**

*Not for Construction*

---

**Legend**

- **L-line Location**
- **Pavement (layer three)**
- **Template**
- **Subgrade fill**
- **P-line Location**
- **Topo**
- **Sub horizon 2 (FR)**
- **Stripped Surface**
- **Culverts**

**Curve Table**

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**Field Surveyor:** CW

**Road Designer:** NB

**Approved By:** XXXX

Section Scale: 1:200
Appendix F  Hemmera Regulatory Approvals and Permitting Review
January 24, 2017
File: 2022-001.01

Nihtat Corporation
P.O. Box 2570
Inuvik, NT X0E 0T0

Attn: Grant Sullivan, Executive Director

Dear Mr. Sullivan,


Hemmera Envirochem Inc. is pleased to provide you with a copy of the draft report.

The enclosed reports are Draft, and are provided for discussion purposes. As such, the reports are not signed. Please review the reports and provide Hemmera with comments and written revisions you feel are appropriate. Once comments and revision requests are received and reviewed, we will finalize the report and circulate signed copies. To aid us in finalizing reports and to avoid unofficial Draft for Discussion reports being used or referenced, we request that you return these Draft Reports to us.

We have appreciated the opportunity to work with you on this project and trust that this report meets your requirements. Please feel free to contact the undersigned by phone or email regarding any questions or further information that you may require.

Regards,
Hemmera Envirochem Inc.

DRAFT

Kimberly Milligan, M.Env.
Project Manager
604.669.0424 (181)
kmilligan@hemmera.com

DRAFT

Project Director
867.456.4865 (712)
muller@hemmera.com
EXECUTIVE SUMMARY

The Government of the Northwest Territories (GNWT) is seeking to construct a 2-5 MW wind farm to reduce the community of Inuvik’s reliance on fossil fuels. Inuvik’s electricity is currently generated exclusively from either diesel or liquefied natural gas, and the Project would be part of a fuel transition for the community. Primary Project components will include wind turbine generators (likely one to three turbines), an all-season access road to the Project site, and an electrical transmission system.

Hemmera Envirochem Inc. (Hemmera) was contracted to conduct a review of potential regulatory constraints for the Project. To identify requirements and assess potential risk, the analysis focuses on the environmental assessment process, permitting requirements, and land tenure and resource use.

The Mackenzie Valley Environmental Impact Review Board (Review Board) is the main instrument responsible for the environmental impact assessment process in the Mackenzie Valley (Review Board, 2004). The first step in the EIA process, the preliminary screening, is generally conducted by a land and water board (e.g. the Gwich’in Land and Water Board (GLWB) for projects in the GSA). If the preliminary screening concludes that the proposed development might cause significant adverse impacts or generate public concern, then the development is sent to the Review Board for an environmental assessment (Review Board, 2004).

It is anticipated that the Project will undergo a preliminary screening, with the GLWB as the primary reviewing agency. It is Hemmera’s view that the Project is unlikely to be referred for environmental assessment as few items and effects are emerging as high-risk. Overall, environmental and community risks associated with the Projects are considered low. Effects to biological components were considered of moderate risk due to potential impacts to migratory birds during Project operations and potential direct and indirect impacts on boreal caribou. Additional understanding of these issues is recommended. Consultation with agencies and Aboriginal groups will be required to gain a better understanding of issues specific to the Project. Risks associated with permitting and tenuring are expected to be low.

This regulatory review is a precursor to necessary baseline studies and environmental assessment based on a project description, and is not considered a legal opinion with respect to named legislations.
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Appendix B  Application Information Requirements
1.0 INTRODUCTION

1.1 PROJECT OVERVIEW

The Government of the Northwest Territories (GNWT) is seeking to construct a 2-5 MW wind farm to reduce the community of Inuvik’s reliance on fossil fuels. Inuvik’s electricity is currently generated exclusively from either diesel or liquefied natural gas, The Project would generate renewable energy intended to supply Inuvik. Primary Project components will include wind turbine generators (likely one to three turbines), an all-season access road to the Project site, and an electrical transmission system.

The site considered for the Inuvik High Point Wind Energy Project (Project), is located approximately 6.5 km northeast of the Inuvik Airport. The Project site is accessible via the Dempster Highway. The Project will include an access road/transmission line connecting the Project infrastructure to the Dempster Highway, near KM 253.5. This route is currently proposed based on the alignment to the Project site and access to quarry locations in the vicinity (Figure 1-1).

The Project is located within the boundaries of the Gwich’in Settlement Area (GSA). The Project is also located outside of the municipal boundary of the Town of Inuvik, which is within the Inuvik Administrative Region, of the GNWT.

Figure 1-1 Project Area
1.2 **SCOPE OF ASSESSMENT**

Hemmera Envirochem Inc. (Hemmera) was contracted to conduct a review of potential regulatory constraints for the Inuvik High Point Wind Energy Project (Project). The intent of the regulatory review was to:

1) Identify the regulatory approvals and permits required by the potential Project.
2) Identify any regulatory issues that could cause substantial delays and / or expense to resolve, or prevent approval (i.e., red flags)?

Hemmera’s experience of other wind development projects (primarily in western Canada), knowledge of environmental assessment in general, direct Inuvik knowledge, familiarity with Northern regulatory frameworks and publically available reports and databases was used as the basis for the regulatory review.

Hemmera undertook a preliminary review of the existing regulatory processes, regional land use planning data as well as accessible public information from the GNWT Community Mapping Atlas (CMA) and other regulatory databases. We also provide interpretation comments from our experience on environmental assessment, permitting, construction and operational monitoring of wind projects.

The analysis of regulatory process focuses on the following areas:

1) Environmental Assessment – a Preliminary Screening under the *Mackenzie Valley Resource Management Act* by the Gwich’in Land and Water Board.
2) Land Tenure and Resource Use – existing land ownership, land rights, and land tenures in the area and activities occurring (e.g. First Nation lands, land reserves, private land, residences, oil and gas pipeline RoWs, protected areas) that may overlap with the Project’s interests in land parcels that would be required for siting, access and transmission.
3) Permitting – Relevant permits for each of three phases (development, construction and operations) are outlined, including general descriptions of their triggers, timelines, content required for applications, and other considerations for successful applications.

This regulatory review is a precursor to necessary baseline studies and environmental assessment based on a project description, and is not considered a legal opinion with respect to named legislations.
2.0 REGULATORY BODIES

Provisions for the establishment of a land use planning board, land and water boards, and of an environmental impact review board for the Mackenzie Valley were included in the Gwich’in Comprehensive Land Claim Agreement (GCLCA) signed in 1992 and officially established in the *Mackenzie Valley Resource Management Act* (S.C. 1998, c.25) (MVRMA) in 1998. The MVRMA provided authorities to co-management boards to carry out land use planning, regulate the use of land and water and, if required, conduct environmental assessments and reviews of large or complex projects. Following these provisions, the Gwich’in Land and Water Board (GLWB), Gwich’in Renewable Resource Board (GRRB), and Gwich’in Land Use Planning Board (GLUPB) were established as co-management boards for the GSA.

2.1 Gwich’in Land and Water Board

The GLWB is one of the four regional boards of the Mackenzie Valley Land and Water Board (MVLWB). The objective of the GLWB is to provide for conservation, development, and use of the land and water resources in the GSA in a manner that will provide the optimum benefit for present and future residents of the GSA, Mackenzie Valley, and Canada (GLWB, 2017).

The GLWB conducts preliminary screenings of projects proposed in the GSA. The GLWB considers whether to issue land use permits and water licences on public and private lands in the GSA in accordance with the *Mackenzie Valley Land Use Regulations* (SOR/98-429). The GLWB may refer a project to the Review Board for environmental assessment based on evidence of significant environmental impacts and/or public concern. A detailed description of the GLWB’s role in environmental assessments of projects proposed in the GSA is described in Section 3.0.

The GLWB will be responsible for conducting a preliminary screening of the Project and issuing a Land Use Permit.

2.2 Gwich’in Renewable Resource Board

The GRRB’s mandate is to act as the main instrument of wildlife, fish and forest management in the GSA. The GRRB consults on a variety of topics, including limitation of harvest, setting Gwich’in Needs Levels, approval of management plans, advice to government, making decisions on commercial harvesting, setting research priorities in the GSA, and more (GRRB, n.d.). The GRRB supports the GLWB’s review of permit Applications, specifically as it relates to items under their mandate.

---

1 The MVLWB’s jurisdiction applies to regions of the Northwest Territories where land claim agreements have yet to be reached. The MVLWB also reviews and issues permits for transboundary projects. As the proposed Project is located within the GSA, this report will focus on the regulatory regime and associated regulators with GSA jurisdiction.
Engagement of the GRRB is necessary to understand the Project context as it applies to fish, wildlife and traditional use/harvest and potential project impacts in the Project area. No formal authorizations are required from the GRRB.

2.3 **Gwich’in Land Use Planning Board**

The Planning Board developed and implements a land use plan for the GSA. In following the principles outlined in the GCLCA and the MVRMA, the Land Use Plan provides for the conservation, development and utilization of land, water and resources (Planning Board, 2003a).

After the approval of the Land Use Plan in August 2003, all licenses, permits or other authorizations relating to the use of land, water or the deposit of waste in the GSA must conform to the Land Use Plan (Planning Board, 2003b). The Land Use Plan is currently being updated, and may be finalized in mid- to late-2017. Through informal conversations, it was indicated that no updates are anticipated that would affect the current Project location, though this would have to be confirmed when the plan is finalized.

If a proposed project doesn’t meet zoning requirement as set out in the Land Use Plan, the GLWB may refer the application to the Planning Board for a Conformity Determination (or may reject the project outright). In these cases, the Planning Board will consider making an exception for the project or an amendment to zoning.

The Project is located in a General Use Zone, which allows for development and is not expected to require a zoning amendment (as described in Section 3.1.1.2).

2.4 **Other Regulatory Mandates**

2.4.1 Municipal

The Project is not located on municipal land. The Town of Inuvik may act as a reviewer and provide comments during the comment period of the GLWB preliminary screening but is not expected to issue authorisations.

2.4.2 Territorial

Departments of the Government of the Northwest Territories are expected to act as technical reviewers for GLWB preliminary screening and be responsible for ancillary permits associated with the Project. Relevant agencies include:

- Department of Environment and Natural Resources
- Department of Lands
- Department of Transportation
• Department of Education, Culture, and Employment (Culture and Heritage Division)
• Aurora College

The GNWT will be responsible for permits for connecting the access road to the Dempster highway. Additional detail on territorial permits is included in Section 4.0.

2.4.3 Federal

Federal agencies may be involved during the permitting process. Similar to the territorial agencies, these agencies are expected to act as technical reviewers for GLWB preliminary screening and be responsible for ancillary permits associated with the Project. Relevant agencies include:

• Fisheries and Oceans Canada
• Transport Canada
• NAV Canada

A description of federal permits typically required for a wind project is in Section 4.0.
3.0 ENVIRONMENTAL IMPACT ASSESSMENT

The Review Board is the main instrument responsible for the environmental impact assessment (EIA) process in the Mackenzie Valley (Review Board, 2004). The first step in the EIA process, the preliminary screening, is generally conducted by a land and water board (e.g. the GLWB for projects in the GSA) or a government agency. The objective of preliminary screening is, in accordance with s.125 of the MVRMA, to determine if a development proposal:

- Might have a significant adverse impact on the environment; or,
- Might be a cause of public concern.

If the preliminary screening concludes that the proposed development might cause significant adverse impacts or generate public concern, then the development is sent to the Review Board for an environmental assessment (Review Board, 2004). Experience to date has been that preliminary screening results in most developments requiring no further assessment (Review Board, 2004).

Land and water boards conduct most preliminary screenings as most developments require land use permits or water licenses. A Land Use Permit is required for any activity that triggers the thresholds defined by the MVLWB and its regional boards. The Project is likely to require a Land Use Permit due to the use of vehicles or machines that would exceed these thresholds (see Appendix A). A summary of the regulatory process followed by the MVLWB and other land and water boards (including the GLWB) is displayed in Figure 3-1.

![Figure 3-1 MVLWB Regulatory Process](source: GLWB, 2017b)
3.1 **PRELIMINARY SCREENING APPLICATION**

This section describes the anticipated requirements for a preliminary screening application (Application), and the process for review. The “Application” refers to the document submitted for preliminary screening – in the case of the Project, it is anticipated to be an application for a land use permit, submitted to and reviewed by the GLWB.

3.1.1 Application Content

This section provides an analysis of the typical information requirements for a preliminary screening by the GLWB. These requirements are based on the Application Checklist that lists the type of information that is (or may be) required as part of a complete application. A copy of this checklist is included in Appendix B. However, amount and type of information required by the GLWB for preliminary screening depends on the size, scale, and nature of the proposed project (MVLWB, 2013). This will be determined during pre-application engagement and consultation activities with Aboriginal groups and agencies. Additional information on this engagement is provided in Section 3.2.

3.1.1.1 Culture and Heritage

Potential impacts to cultural and heritage resources must be considered in the Application, including effects to historic properties, archaeological resources, and effects on Aboriginal lifestyle. The potential for historic properties and archaeological resources can be understood through dialogue with the Culture and Heritage Division of the Department of Education, Culture, and Employment. If these resources are identified on the Project site, the Culture and Heritage Division will support the Proponent in developing mitigation measures to address potential impacts of Project construction and operation. Under Section 12 of the *Mackenzie Valley Land Use Regulations*, if a suspected historic or archaeological site or burial site is discovered during Project construction or operations, work shall be suspended immediately and the GLWB shall be notified immediately.

The Gwich’in Tribal Council, Department of Cultural Heritage is another source of information about local heritage sites. Heritage sites of special value are identified in the Land Use Plan and protected through the Gwich’in Conservation Zone or Gwich’in Special Management Zone designations. The Project is not located within either of these types of zones.

Should historic and archaeological resources be identified within the Project area, is anticipated that these could be managed through mitigation measures developed in collaboration with the GLWB and the Culture and Heritage Division. Hemmera notes that mitigation measures for these resources are well-established for wind projects.
Effects on Aboriginal lifestyle can be determined in consultation with the GRRB and with Aboriginal groups. Through informal conversations with GLWB representatives, it was indicated that hunting and trapping activities are not tenured, but rather documented informally by the GRRB. At this stage in the project planning, consultation has not been initiated to better understand potential effects on Aboriginal lifestyle. However, no evidence of human use (e.g. trails, clearings) was identified on High Point or in the proposed road corridor during the October 14th site visit.

Potential effects to culture and heritage are not anticipated to pose a major risk to the Project, as the Project is located in a General Use Zone, and mitigation measures for historic and archaeological resources are well-established for wind projects. Consultation would be required to better understand effects of the Project on Aboriginal lifestyle.

3.1.1.2 Social and Economic

Social and economic considerations that may need to be considered include planning/zoning changes or conflicts, airport operations, increase in urban facilities or service use, and general risks to the community. Aesthetics should also be considered – as no guidelines for visual resources exist for this jurisdiction, methods for measuring effects to visual resources would be determined in consultation with the various agencies and Aboriginal groups.

According to the Land Use Plan, the Project is located within a Gwich’in General Use Zone (Planning Board, 2003a). These are areas where all land uses are allowable with the necessary approvals. This zone of the Land Use Plan imposes no conditions (Planning Board, 2003a).

Through informal conversations with a representative of the GNWT Department of Transportation, it was indicated that structures proposed within an 8 km radius of the Inuvik Airport are reviewed by the Department of Transportation. As the Project is located within this radius, consultation will be required to determine appropriate navigational aids and any other best management practices required. As indicated in Section 4.0, confirmation would also be required from NAV CANADA prior to construction and from Transport Canada for construction activities.

Structures proposed in the vicinity of the Inuvik Airport are further regulated by the Inuvik Airport Zoning Regulations (SOR/81-707). These regulate the height of construction within the airport’s approach surface, outer surface, and transitional surface (as defined in the regulation). These surfaces are displayed in Figure 3-2. During Project design, if structures are proposed in the zones displayed in Figure 3-2, heights of structures (e.g. turbines transmission structures) would need to comply to the restrictions described in the Inuvik Airport Zoning Regulations. The runways are roughly oriented east to west, and the approach surface extends in the same orientation. As the Project is located to the north of the airport, the risk associated with the Inuvik Airport is considered low.
The Shell Lake Water Aerodrome is located 9 km southwest of the Project area. From a regulatory perspective, the authority for the use of lands located outside of aerodrome property rests with territorial/municipal levels of government (Transport Canada, 2013). The only exception to this fact occurs where an airport zoning regulation, made pursuant to the Aeronautics Act (R.S.C., 1985, c.A-2), is in force. No airport zoning regulation in force for the Shell Lake Water Aerodrome. The municipality’s airport zoning regulations apply only to the Inuvik Airport, and not the Shell Lake Water Aerodrome (Town of Inuvik, 2015). The GNWT’s Commissioner’s Public Airport Lands Regulations (R-0020-2006) regulate development on lands designated as Commissioner’s Public Airport Lands. The Shell Lake Water Aerodrome does not have this designation. As such, no authorizations are expected to be required for construction in the vicinity of the Shell Lake Water Aerodrome. However, it is recommended that the Proponent follow best practices identified in TP1247E: Aviation – Land Use in Vicinity of Aerodromes, specifically as they relate to wind turbines and wind farms (Transport Canada, 2013).

Construction traffic would need to be considered in the Application, but it is anticipated that the volume of traffic would not substantially increase, and that the duration of effects would be limited.

Adverse impacts to the community as a result of the Project are not anticipated, mainly because the project will not require a large influx of workers or newcomers to the community. Rather, benefits to the community are anticipated in the form of local employment opportunities and the availability of a clean energy source.
1. This map is not intended to be a standalone document, but a visual aid of the information contained within the referenced Report. It is intended to be used in conjunction with the scope of services and limitations described therein.

2. All mapped features are approximate and should be used for discussion purposes only.

Sources:
- Background image: ESRI World Topographic Map
3.1.1.3 Biological Environment

The Land Use Permit application will be required to consider potential effects to biological resources, including vegetation, fish and wildlife, waterfowl population changes, breeding disturbance, population reduction, species diversity change, health changes, and behavioural changes.

As observed during a site visit conducted on October 14, 2016, ground cover in the Project area was primarily made up of moss, small shrubs, and other low vegetation. The southern end of the proposed road alignment was sparsely-treed muskeg with moss and small shrubs. No tree growth was observed on High Point. More detailed vegetation classification would be acquired through additional studies.

No water features were observed on High Point. However, water features of varying sizes and ephemeral nature were identified in the muskeg-dominated area surrounding High Point. Two water features were observed within the proposed road alignment, the widest of which appeared to be roughly 2m. Without more detailed baseline study, it is unclear if the watercourses to be crossed by the access road would contain a Commercial, Recreational or Aboriginal (CRA) Fishery under the federal Fisheries Act. Regardless, design standards for culverts to not impede fish passage are well understood and commonly applied process using measured watercourse flows. As such, impacts to fish populations are not expected to be significant.

Impacts to waterfowl and migratory birds can typically be mitigated at the construction phase through standard best management practices. Summer nesting waterfowl arrive at the Mackenzie Delta primarily via the Central flyway. Further study to understand waterfowl and migratory bird populations in the Project vicinity would be required to understand potential impacts of Project operations. Hemmera notes that, due to the nature of wind project operations, potential impacts to birds can be considered a moderate risk to project permitting.

While caribou (Rangifer tarandus) could potentially occur in the Project area, it was indicated during prefeasibility meetings that they should not be considered a limiting constraint to the Project. Barren Ground Caribou (Rangifer tarandus groenlandicus) previously occurred in the area, but have not been observed in the recent past. The Project is on the periphery of the Cape Bathurst and Bluenose West herds of this subspecies, and they should be considered potentially present in the area in the winter due to these historic occurrences. Woodland caribou (Rangifer tarandus caribou) occur throughout the boreal region and should be considered potentially present year-round. Anecdotal evidence indicates that caribou were historically observed near Campbell Lake, 9.5 km southeast of the Project, but have not been seen in recent years. However, due to the value attributed to caribou by Aboriginal groups, and the Schedule I listing of Boreal population of woodland caribou under the Species at Risk Act, potential impacts to caribou is flagged as a potential area of risk.
Though the area is considered too far north for bat populations, unconfirmed sightings have been recently reported near Tsiigehtchic, Aklavik, and Fort McPherson. Other species that were indicated to potentially occur in the Project area include moose (Alces alces), wolverine (Gulo gulo), lynx (Lynx canadensis), wolves (Canis lupus), cross fox and red fox (Vulpes vulpes), muskrat (Ondatra zibethicus), beaver (Castor Canadensis), bears, song birds, raptors, and waterfowl. Sheep and goat species are not anticipated to be in the area. Access amelioration for hunting and predation is not anticipated to be significant as the Project is largely located above the treeline. Additional wildlife studies may be required to provide additional information on these species and other wildlife values.

3.1.1.4 Physical – Chemical Effects

Physical and/or chemical effects of the Project on groundwater, surface water, noise, land, and air/climate/atmosphere may need to be considered in the Application. Due to the nature of construction and operation of a wind project, no significant impacts are anticipated related of these items are anticipated, with the exception of noise.

No receptors were observed in the vicinity of the Project area. No guidelines exist on noise assessment for this jurisdiction. No physical and/or chemical effects are anticipated to pose significant risk to the project.

3.2 Consultation and Engagement

Issues specific to a project are scoped during consultation. This is especially important to the Project as a tool to refine the checklist for application requirements (GLWB, 2017b) and ensure that Project-specific impacts are scoped into (or out of) the assessment.

Engagement records and engagement plans are required with Applications in accordance with the Engagement and Consultation Policy (MVLWB, 2013b) and Engagement Guidelines for Applicants and Holders of Land Use Permits and Water Licences (MVLWB, 2014). Engagement should be initiated well in advance of the submission of the application to allow affected parties sufficient time to review and discuss the information with the Proponent (GLWB, 2017b).

3.3 Application Review Process

Land Use Permit Applications are reviewed by the Board for completeness and accuracy. Completeness checks are completed by the Board within 10 days of submission. If the Application is deemed incomplete the proponents are notified with a list of deficiencies. When the Board is satisfied that the Application contains all the necessary information the proponent is notified that the Application has been accepted for review. The Application is made publicly available via the Board’s website and is distributed to applicable reviewers, which generally includes: federal and territorial government departments, land owners, affected communities, First Nation governments, Renewable Resource Boards, Heritage departments other interested parties. The board also notifies the Review Board of the active Application.
The Board conducts a review period, where reviewers evaluate the Application and provide comments. Review periods will vary depending on the scope, scale, and location of a proposed project. Comments received are forwarded to the project proponent upon completion of the review period for a response. Following proponent responses the Board completes its review.

After the acceptance of complete application, a Board review is typically completed within 42 days for a Type A application and within 15 days for a Type B application. The Board may issue a licence, conduct a hearing, require further studies, refer the project to the Review Board or refuse to issue a licence.

As noted, the Project is proposed in a General Use Zone, meaning that all land uses are possible. Through the land use planning process, communities identify areas they believe should be protected due to traditional use, cultural heritage, wildlife, fish, forests, water and other reasons (Planning Board, 2003a). These areas are defined as Gwich’iin Special Management Zones or Gwich’in Conservation Zones. Values specific to the Project area will be better understood through additional research and consultation, but the area currently has not been defined as requiring protection in the Land Use Plan.

A referral to the Review Board would lengthen regulatory timelines. About 5% of all developments that go through preliminary screening are referred to environmental assessment (GLWB, 2017b). These projects are typically larger in scope and with larger community and/or environmental impacts than those anticipated to result from the Project. Projects currently under review include all-season roads and large mining projects (Review Board, 2017). Preliminary discussions with GLWB, GRRB, and Planning Board representatives align with our view that the Project is unlikely to be referred for environmental assessment as few items and effects are emerging as high-risk.
## 4.0 PERMITS

Table 4-1 lists the authorizations potentially required from the federal government, Government of the Northwest Territories, and from the Gwich’in Land and Water Board.

### Table 4-1 Authorizations Potentially Required for the Project

<table>
<thead>
<tr>
<th>Act/Regulation</th>
<th>Agency</th>
<th>Nature of Authorization/Approval Request</th>
<th>Status/Phase Required</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>Federal</strong></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td><em>Fisheries Act</em>, R.S.C 1985, c. F-14</td>
<td>Fisheries and Oceans Canada (DFO)</td>
<td>Authorization under sub-section 35(2).</td>
<td>Prior to construction</td>
</tr>
<tr>
<td><em>Civil Air Navigation Services Commercialization Act</em> S.C. 1996, c. 20</td>
<td>NAV CANADA</td>
<td>Application - Land Use Proposal Submission Form</td>
<td>Prior to construction</td>
</tr>
<tr>
<td><em>Canadian Aeronautics Act</em> R.S.C. 1985, c. A-2</td>
<td>Transport Canada</td>
<td>Approval of Aeronautical Obstruction Clearance Form</td>
<td>Construction</td>
</tr>
<tr>
<td><em>Explosives Act</em> R.S.C. 1985, c. E-17</td>
<td>Natural Resources Canada</td>
<td>Storage (day use) Explosive Permit if explosives are required</td>
<td>Construction - to be provided by federally licensed contractor</td>
</tr>
<tr>
<td><em>Transportation of Dangerous Goods Act, 1992</em> (1992, c. 34)</td>
<td>Transport Canada</td>
<td>Explosives transport if explosives are required</td>
<td>Construction – to be provided by federally licensed contractor</td>
</tr>
<tr>
<td><em>Migratory Birds Convention Act, 1994</em>, S.C. 1994, c. 22</td>
<td>Environment Canada</td>
<td>Permit(s) under the <em>Migratory Birds Regulation of the Migratory Birds Convention Act</em>: (1) the handling of migratory bird carcasses during monitoring of operations</td>
<td>Prior to operations</td>
</tr>
<tr>
<td><strong>Government of the Northwest Territories</strong></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td><em>Scientists Act</em> R.S.N.W.T. 1998, c.S-4</td>
<td>Aurora Institute</td>
<td>Scientific Research Licence required for field surveys</td>
<td>Prior to field surveys</td>
</tr>
<tr>
<td><em>Wildlife Act</em> S.N.W.T. 2013, c.30</td>
<td>Department of Environment and Natural Resources</td>
<td>Required for wildlife field surveys, and/or handling wildlife.</td>
<td>Prior to field surveys</td>
</tr>
<tr>
<td><em>Northwest Territories Lands Act</em> S.N.W.T. 2014, c.13</td>
<td>Department of Lands</td>
<td>Short-term access to lands for the purpose of extracting granular material (quarry permit)</td>
<td>Prior to construction</td>
</tr>
<tr>
<td><em>Public Highways Act</em> R.S.N.W.T. 1998, c.P-13</td>
<td>Department of Transport</td>
<td>Permit for the access road to enter a highway</td>
<td>Prior to construction</td>
</tr>
<tr>
<td><strong>Gwich’in Land and Water Board</strong></td>
<td></td>
<td></td>
<td></td>
</tr>
</tbody>
</table>
4.1 **ANTICIPATED PERMITTING SCHEDULE**

The proposed Project occurs in a region where physical (e.g. flowing versus frozen water) and biological (e.g. presence of migratory birds) processes can be dramatically different depending on the season. We anticipate the timeline for the permitting process will be determined by the time required to collect baseline biophysical data. Some regional biological information and good weather data is expected to be available. We recommend that the GLWB is engaged regarding baseline data requirements when the Project location has been finalized to better understand any schedule risk.

5.0 **TENURE**

The Project site is located entirely on territorial Commissioner’s Land within the GSA, the Proponent will require a land tenure prior to development. Commissioner’s Land is administered through the GNWT, and land tenures are issued through the GNWT Department of Lands.

Gwich’in rights as identified in the GCLCA are applicable to Commissioner’s Land within the GSA. Consultation with Aboriginal groups and the GLWB and GRRB is recommended to understand how these rights are exercised within the Project vicinity.

A portion of the access/transmission corridor being considered overlaps with Gwich’in Private Land. An Access Benefits Agreement, administered through the Gwich’in Tribal Council, is required for permanent structures on Gwich’in Private Land.

No overlap with other tenures has been identified, and no risks associated with tenuring are identified for this Project.
6.0 RISK REGISTER

For this prefeasibility study, Hemmera has collected information through a one-day site visit, meetings with regulators, and a review of publicly available information. Based on our experience in the investigation, development and construction of wind energy development projects, preliminary risks have been identified in Table 6-1. Hemmera notes that the scope of a prefeasibility study is limited, and that additional studies and consultation are required to confirm risk associated with issues identified below.

Issues are categorized as follows:

- “High” denotes key issues that may result in approvals not acquired;
- “Medium” denotes topics to be addressed that may require above average consultation and or mitigation measures than a typical wind project of similar size; and
- “Low” indicates that there is no expected issue beyond the typical expected for a wind farm of this size.

Table 6-1 Risk Register

<table>
<thead>
<tr>
<th>Component</th>
<th>Concern</th>
<th>Comments</th>
</tr>
</thead>
<tbody>
<tr>
<td>Environmental Assessment</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Culture and heritage</td>
<td>Low</td>
<td>• Project is located in a General Use Zone, and mitigation measures for</td>
</tr>
<tr>
<td></td>
<td></td>
<td>historic and archaeological resources are well-established for wind</td>
</tr>
<tr>
<td></td>
<td></td>
<td>projects.</td>
</tr>
<tr>
<td></td>
<td></td>
<td>• Consultation required to better understand effects of the Project on</td>
</tr>
<tr>
<td></td>
<td></td>
<td>Aboriginal lifestyle</td>
</tr>
<tr>
<td>Social and economic</td>
<td>Low</td>
<td>• Project located in General Use Zone.</td>
</tr>
<tr>
<td></td>
<td></td>
<td>• As the Project is located to the north of the Inuvik Airport, the risk</td>
</tr>
<tr>
<td></td>
<td></td>
<td>associated with the Inuvik Airport is considered low.</td>
</tr>
<tr>
<td></td>
<td></td>
<td>• Benefits to the community are anticipated in the form of local</td>
</tr>
<tr>
<td></td>
<td></td>
<td>employment opportunities and the availability of a clean energy source.</td>
</tr>
<tr>
<td>Biological environment</td>
<td>Medium</td>
<td>• Potential impacts to migratory birds during Project operations.</td>
</tr>
<tr>
<td></td>
<td></td>
<td>• Potential direct and indirect (increased harvesting) impacts on</td>
</tr>
<tr>
<td></td>
<td></td>
<td>boreal caribou.</td>
</tr>
<tr>
<td></td>
<td></td>
<td>• Impacts to fish populations are not expected to be significant</td>
</tr>
<tr>
<td>Physical – Chemical Effects</td>
<td>Low</td>
<td>• No noise receptors were observed in the vicinity of the Project area.</td>
</tr>
<tr>
<td></td>
<td></td>
<td>• No physical and/or chemical effects are anticipated to pose significant</td>
</tr>
<tr>
<td></td>
<td></td>
<td>risk to the project.</td>
</tr>
<tr>
<td>Permits</td>
<td></td>
<td></td>
</tr>
<tr>
<td>(Permits outlined in Section 4.0)</td>
<td>Low</td>
<td>• No permits listed are anticipated to present a risk to the Project.</td>
</tr>
<tr>
<td>Tenure</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Tenure</td>
<td>Low</td>
<td>• No overlapping tenures identified.</td>
</tr>
</tbody>
</table>
7.0 CONCLUSION

Hemmera Envirochem Inc. (Hemmera) was contracted to conduct a review of potential regulatory constraints for the Inuvik High Point Wind Energy Project (Project). The intent of the regulatory review was to:

1) Identify the regulatory approvals and permits required by the potential Project.
2) Identify any regulatory issues that could cause substantial delays and / or expense to resolve, or prevent approval.

To identify and assess these considerations, the analysis focuses on the environmental assessment process, permitting requirements, and land tenure and resource use. From a regulatory standpoint, the Project is considered to be overall low risk. Effects to biological components were considered of moderate risk due to potential impacts to migratory birds during Project operations and potential direct and indirect impacts on boreal caribou. Additional understanding of these issues is recommended. Consultation with agencies and Aboriginal groups will be required to gain a better understanding of issues specific to the Project. It is anticipated that the Project will require a preliminary screening. It is Hemmera’s view that the Project is unlikely to be referred for environmental assessment as few items and effects are emerging as high-risk. This regulatory review is a precursor to necessary baseline studies and environmental assessment based on a project description, and is not considered a legal opinion with respect to named legislations.
8.0 CLOSURE

In performing this Work, Hemmera has relied in good faith on information provided by others, and has assumed that the information provided by those individuals is both complete and accurate. This Work was performed to current industry standard practice for similar environmental work, within the relevant jurisdiction and same locale. The findings presented herein should be considered within the context of the scope of work and project terms of reference; further, the findings are time sensitive and are considered valid only at the time the Report was produced. The conclusions and recommendations contained in this Report are based upon the applicable guidelines, regulations, and legislation existing at the time the Report was produced; any changes in the regulatory regime may alter the conclusions and/or recommendations.

We sincerely appreciate the opportunity to have assisted you with this project and if there are any questions, please do not hesitate to contact the undersigned by phone at 867.456.4865.

Report prepared by:
Hemmera Envirochem Inc.

DRAFT

Kimberly Milligan, M.Env.
Project Manager

Report peer reviewed by:
Hemmera Envirochem Inc.

DRAFT

Project Director
9.0 REFERENCES


Gwich’in Land and Water Board. 2017b. Regulatory Process. Available at https://glwb.com/content/regulatory-process


APPENDIX A

Land Use Activities Requiring a Land Use Permit
(Source: MVLWB, 2013a)
2.1 Land Use Activities That Require a Land Use Permit

On land outside the boundaries of a local government, a type A or B LUP is required for:

<table>
<thead>
<tr>
<th>Activity</th>
<th>Type A Land Use Permit</th>
<th>Type B Land Use Permit</th>
</tr>
</thead>
<tbody>
<tr>
<td>explosives</td>
<td>use of a quantity equal to or exceeding 150 kg in any 30-day period</td>
<td>use of a quantity equal to or exceeding 50 kg, but less than 150 kg, in any 30-day period</td>
</tr>
<tr>
<td>use of vehicles or machines</td>
<td>use of a vehicle or machine of a weight equal to or exceeding 10 tonnes, other than on a road or on a community landfill, quarry site, or airport</td>
<td>use of a vehicle the net weight of which equals or exceeds 5 tonnes but is less than 10 tonnes, or the use of a vehicle of any weight that exerts a pressure on the ground equal to or exceeding 35 kPa, other than on a road or within a community landfill, quarry site, or airport</td>
</tr>
<tr>
<td>storage of fuel (single container)</td>
<td>use of a single container that has a capacity equal to or exceeding 4,000 litres</td>
<td>use of a single container for the storage of petroleum fuel that has a capacity that equals or exceeds 2,000 litres but is less than 4,000 litres</td>
</tr>
<tr>
<td>storage of fuel (facility)</td>
<td>establishment of a petroleum fuel storage facility with a capacity equal to or exceeding 80,000 litres</td>
<td>establishment of a petroleum fuel storage facility with a capacity equal to or exceeding 4,000 litres but is less than 80,000 litres</td>
</tr>
<tr>
<td>Activity</td>
<td>Type A Land Use Permit</td>
<td>Type B Land Use Permit</td>
</tr>
<tr>
<td>------------------------</td>
<td>----------------------------------------------------------------------------------------</td>
<td>----------------------------------------------------------------------------------------</td>
</tr>
<tr>
<td>machinery</td>
<td>use of a self-propelled, power-driven machine for moving earth or clearing land</td>
<td></td>
</tr>
<tr>
<td>machinery</td>
<td>use of a stationary, power-driven machine, other than a power saw, for hydraulic prospecting, earth moving, or land clearing</td>
<td></td>
</tr>
<tr>
<td>lines, trails, or right-of-ways</td>
<td>leveling, grading, clearing, cutting, or snowplowing of a line, trail or right-of-way (other than a road or existing access trail to a building) that exceeds 1.5 metres in width and 4 hectares, for a purpose other than the grooming of recreational trails</td>
<td>leveling, grading, clearing, cutting or snowplowing of any line, trail or right-of-way (other than a road or existing access trail to a building) that exceeds 1.5 metres in width but does not exceed 4 hectares for a purpose other than the grooming of recreational trails</td>
</tr>
<tr>
<td>campsites</td>
<td>use of a campsite outside of a territorial park for a duration of or exceeding 400 person-days</td>
<td>use of a campsite outside of a territorial park for a duration of or exceeding 200 person-days but less than 400 person-days</td>
</tr>
<tr>
<td>buildings</td>
<td>-</td>
<td>construction of a building with a footprint of more than 100 m² and a height of more than 5 metres</td>
</tr>
<tr>
<td>Activity</td>
<td>Type A Land Use Permit</td>
<td>Type B Land Use Permit</td>
</tr>
<tr>
<td>--------------</td>
<td>--------------------------------------------------------------------------------------</td>
<td>--------------------------------------------------------------------------------------</td>
</tr>
<tr>
<td>drilling</td>
<td>use of power-driven, earth-drilling machinery the operating weight of which, excluding the weight of drill rods, stems, bits, pumps, and other ancillary equipment, equals or exceeds 2.5 tonnes for a purpose other than the drilling of holes for building piles or utility poles or the setting of explosives within the boundaries of the local government</td>
<td>use of power-driven, earth-drilling machinery the operating weight of which, excluding the weight of drill rods, stems, bits, pumps, and other ancillary equipment, equals or exceeds 500 kg but is less than 2.5 tonnes, for a purpose other than the drilling of holes for building piles or utility poles or the setting of explosives within the boundaries of the local government</td>
</tr>
<tr>
<td>campsites</td>
<td>use of a campsite outside of a territorial park for a duration of or exceeding 400 person-days</td>
<td>use of a campsite outside of a territorial park for a duration of or exceeding 200 person-days but less than 400 person-days</td>
</tr>
<tr>
<td>storage of fuel (facility)</td>
<td>establishment of a petroleum fuel storage facility with a capacity equal to or exceeding 80,000 litres</td>
<td>-</td>
</tr>
<tr>
<td>machinery</td>
<td>use of a stationary, power-driven machine, other than a power saw, for hydraulic prospecting, earth moving, or land clearing</td>
<td>-</td>
</tr>
</tbody>
</table>

On land within the boundaries of a local government, a type A or B LUP is required for:
APPENDIX B
Application Information Requirements
(Source: MVLWB, 2013a)
Appendix B - Template for Environmental and Resource Impacts and Mitigation Measures Information

Proponents can use the following table to describe the effects of the proposed land use operation on land, water, flora, and fauna, as well as socio-economic impacts. This list is not all-inclusive, so if other impacts have been identified, proponents are encouraged to include them. Other sources of guidance to help identify potential impacts include the:

- Mackenzie Valley Environmental Impact Review Board’s *Environmental Impact Assessment Guidelines* and *Socio-Economic Impact Assessment Guidelines*; and
- Yukon Environmental and Socio-economic Assessment Board’s *Proponent’s Guide to Project Proposal Submission to a Designated Office* (see sections 6.0 and 7.0).

**Physical – Chemical Effects**

<table>
<thead>
<tr>
<th>IMPACT</th>
<th>MITIGATION</th>
</tr>
</thead>
<tbody>
<tr>
<td>Ground Water</td>
<td></td>
</tr>
<tr>
<td>□ Water table alteration</td>
<td></td>
</tr>
<tr>
<td>□ Water quality changes</td>
<td></td>
</tr>
<tr>
<td>□ Infiltration changes</td>
<td></td>
</tr>
<tr>
<td>□ Other</td>
<td></td>
</tr>
<tr>
<td>Surface Water</td>
<td></td>
</tr>
<tr>
<td>□ Flow or level changes</td>
<td></td>
</tr>
<tr>
<td>□ Water quality changes</td>
<td></td>
</tr>
<tr>
<td>□ Drainage pattern changes</td>
<td></td>
</tr>
<tr>
<td>□ Temperature</td>
<td></td>
</tr>
<tr>
<td>□ Wetland change/loss</td>
<td></td>
</tr>
<tr>
<td>□ Other</td>
<td></td>
</tr>
<tr>
<td>Noise</td>
<td></td>
</tr>
<tr>
<td>□ Noise in/near water</td>
<td></td>
</tr>
<tr>
<td>□ Noise increase</td>
<td></td>
</tr>
<tr>
<td>□ Other</td>
<td></td>
</tr>
<tr>
<td>Land</td>
<td></td>
</tr>
<tr>
<td>□ Geologic structure changes</td>
<td></td>
</tr>
<tr>
<td>□ Soil contamination</td>
<td></td>
</tr>
<tr>
<td>□ Buffer zone loss</td>
<td></td>
</tr>
</tbody>
</table>
### Biological Environment

<table>
<thead>
<tr>
<th>IMPACT</th>
<th>MITIGATION</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>Vegetation</strong></td>
<td></td>
</tr>
<tr>
<td>☐ Species composition</td>
<td></td>
</tr>
<tr>
<td>☐ Species introduction</td>
<td></td>
</tr>
<tr>
<td>☐ Toxin/heavy accumulation</td>
<td></td>
</tr>
<tr>
<td>☐ Other (such as species distribution, any rare species or species at risk, plant phenology, growth, and reproduction)</td>
<td></td>
</tr>
<tr>
<td><strong>Wildlife and fish</strong></td>
<td></td>
</tr>
<tr>
<td>☐ Effects on rare, threatened, or endangered species</td>
<td></td>
</tr>
<tr>
<td>☐ Fish population changes</td>
<td></td>
</tr>
<tr>
<td>☐ Waterfowl population changes</td>
<td></td>
</tr>
<tr>
<td>☐ Breeding disturbance</td>
<td></td>
</tr>
<tr>
<td>☐ Population reduction</td>
<td></td>
</tr>
<tr>
<td>☐ Species diversity change</td>
<td></td>
</tr>
<tr>
<td>☐ Health changes</td>
<td></td>
</tr>
<tr>
<td>☐ Behavioural changes</td>
<td></td>
</tr>
<tr>
<td>☐ Habitat changes/effects</td>
<td></td>
</tr>
<tr>
<td>☐ Game species/effects</td>
<td></td>
</tr>
<tr>
<td>☐ Toxins/heavy metals</td>
<td></td>
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<tr>
<td>☐ Forestry changes</td>
<td></td>
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<tr>
<td>☐ Agricultural changes</td>
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<tr>
<td>☐ Other</td>
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</tbody>
</table>
## Interacting Environment

<table>
<thead>
<tr>
<th>IMPACT</th>
<th>MITIGATION</th>
</tr>
</thead>
<tbody>
<tr>
<td>Habitat and Communities</td>
<td></td>
</tr>
<tr>
<td>□ Predator-prey</td>
<td></td>
</tr>
<tr>
<td>□ Wildlife habitat/ecosystem composition changes</td>
<td></td>
</tr>
<tr>
<td>□ Reduction/removal of keystone or endangered species</td>
<td></td>
</tr>
<tr>
<td>□ Removal of wildlife corridor or buffer zone</td>
<td></td>
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<tr>
<td>□ Other</td>
<td></td>
</tr>
<tr>
<td>Social and Economic</td>
<td></td>
</tr>
<tr>
<td>□ Planning/zoning changes or conflicts</td>
<td></td>
</tr>
<tr>
<td>□ Increase in urban facilities or services use</td>
<td></td>
</tr>
<tr>
<td>□ Rental house</td>
<td></td>
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<tr>
<td>□ Airport operations/capacity changes</td>
<td></td>
</tr>
<tr>
<td>□ Human health hazard</td>
<td></td>
</tr>
<tr>
<td>□ Impair the recreational use of water or aesthetic quality</td>
<td></td>
</tr>
<tr>
<td>□ Affect water use for other purposes</td>
<td></td>
</tr>
<tr>
<td>□ Affect other land use operations</td>
<td></td>
</tr>
<tr>
<td>□ Quality of life changes</td>
<td></td>
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<tr>
<td>□ Other</td>
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</tbody>
</table>
## Cultural and Heritage

<table>
<thead>
<tr>
<th>IMPACT</th>
<th>MITIGATION</th>
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</thead>
<tbody>
<tr>
<td>Habitat and Communities</td>
<td></td>
</tr>
<tr>
<td>☐ Effects to historic property</td>
<td></td>
</tr>
<tr>
<td>☐ Increased economic pressure on historic properties</td>
<td></td>
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<tr>
<td>☐ Change to or loss of historic properties</td>
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</tr>
<tr>
<td>☐ Change to or loss of historic resources</td>
<td></td>
</tr>
<tr>
<td>☐ Change to or loss of archaeological resources</td>
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<tr>
<td>Social and Economic</td>
<td></td>
</tr>
<tr>
<td>☐ Increased pressure on archaeological sites</td>
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<tr>
<td>☐ Effects on Aboriginal lifestyle</td>
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<tr>
<td>☐ Other</td>
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</table>