Strategic Assessment of Climate Change Technical Report

Cedar LNG Project

November 2021

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Executive Summary

Cedar LNG Partners LP (Cedar), a Haisla Nation-led partnership with Pembina Pipeline Corporation, is proposing to construct and operate the Cedar LNG Project (the Project), a liquefied natural gas (LNG) export facility within the District of Kitimat, British Columbia. The Project will be located on Haisla Nation-owned land within the Nation's traditional territory, approximately 3 kilometres (km) west across Kitimat Arm from Kitamaat Village and approximately 10 km southwest of Kitimat's town centre.

This report has been prepared to help meet the Strategic Assessment of Climate Change (SACC) requirements established by Environment and Climate Change Canada (ECCC). The SACC is intended to provide a framework through which to consider climate change in federal impact assessments and to specifically address the extent to which the effects of a designated project hinder or contribute to the Government of Canada's ability to meet its commitments in respect of climate change (Impact Assessment Act, s. 22(1)(i)). The SACC is supplemented by the draft Technical Guide Related to the Strategic Assessment of Climate Change (ECCC 2021a), referred to herein as the draft Technical Guide.

The Project will reduce the ability of carbon sinks to sequester carbon due to the clearing of biomass. Assuming that all lost carbon is oxidized to carbon dioxide (as per the draft Technical Guide), the total carbon sink impact for the cleared area associated with the Project is 6,384 t CO_2.

Upstream GHG emissions are those that occur from the production, processing, and transmission of the natural gas prior to use by the Project. A screening assessment for upstream emissions indicated that the Project's upstream GHG emissions are likely over 500 kt carbon dioxide equivalent (CO_2e). Using the upstream GHG emission intensities presented in the draft Technical Guide, the total annual emissions range between 975 and 959 kt CO_2e per year, which corresponds with an upstream GHG emission intensity of approximately 0.32 t CO_2e/t LNG after 2030. These upstream emissions are considered incremental to existing natural gas production, processing, and transmission GHG emissions.

A Best Available Technology and Best Environmental Practices (BAT/BEP) assessment identified potential GHG emission reduction technologies and practices that may be applicable to the Project. The technologies and practices were evaluated for technical feasibility, GHG reduction potential, and economic feasibility. A BAT/BEP scenario that gives a conservatively high estimate of GHG emissions was selected for the Project. The key BAT selection is the connection to the BC electricity grid, which will result in reductions of 537,508 t CO_2e per year over a natural gas generator system, corresponding to a 96% reduction. A net-zero emission plan was developed based on the selected BAT/BEP. The net GHG emissions after the implementation of BAT/BEP are estimated for each year of Project construction and operation. Net GHG emissions after 2050 will be offset with offset credits, resulting in net-zero emissions for the Project.

Abbreviations

°C	degrees Celsius
Cedar	Cedar LNG Partners LP
BCLCS	British Columbia Land Class System
CO_2	carbon dioxide
CO_2e	carbon dioxide equivalent
CSI	Carbon Sink Impact
CWHvm1	coastal western hemlock very wet maritime subzone
EAO	Environmental Assessment Office
FLNG	floating liquefied natural gas
GHG	greenhouse gas
ha	hectare
km	kilometre
LNG	liquefied natural gas
m	metre
m^3	cubic metre
mm	millimetre
MCC	maximum carrying capacity
TDR	Technical Data Report
the Application	the Application for an Environmental Assessment Certificate
the Project	the Cedar LNG Project

Glossary

Floating liquefied natural gas (FLNG) facility	A water-based liquefied natural gas production facility that is purpose-built to liquefy and store liquefied natural gas and transfer it to LNG carriers for global export.
Front end engineering design (FEED)	The basic engineering design phase which comes after the Pre-FEED and before the start of engineering, procurement and construction (EPC) work. The scope focuses on technical issues/requirements and identifying main costs for construction of a project.
Liquefied natural gas (LNG)	Natural gas that has been cooled to approximately -162°C where the methane and other components condense from gas to liquid form. In its liquid state, natural gas takes up 1/600 of the space that the gaseous phase occupies.
LNG Carrier	A marine cargo ship with specialized cryogenic tanks that is designed for transporting liquefied natural gas.
LNG facility	Cedar’s proposed floating liquefied natural gas facility and marine export terminal
Natural gas	A naturally occurring hydrocarbon gas mixture consisting primarily of methane (typically >98%) plus varying amounts of ethane, propane, butanes, pentanes, higher molecular weight hydrocarbons, hydrogen sulfide, carbon dioxide, water vapor, and sometimes helium and nitrogen.
Preliminary front end engineering design (Pre-FEED)	An engineering study that establishes the design basis, initial project concept, specifications and other technical and operational requirements for a project before starting the FEED.
Project Area	The area to be utilized by the Project and includes District Lot 99 and marine waters extending approximately 500 m offshore
tonne	A metric unit of mass equal to 1,000 kilograms

1.0 INTRODUCTION

Cedar LNG Partners LP (Cedar), a Haisla Nation-led partnership with Pembina Pipeline Corporation, is proposing to construct and operate the Cedar LNG Project (the Project), a liquefied natural gas (LNG) export facility within the District of Kitimat, British Columbia. The Project will be located on Haisla Nation-owned land within the Nation's traditional territory, approximately 3 kilometres (km) west across Kitimat Arm from Kitamaat Village and approximately 10 km southwest of Kitimat's town centre.

The Project is expected to process and liquefy approximately 400 million standard cubic feet per day of natural gas from western Canada into approximately 3 million tonnes of LNG per year.

The Project lifetime can be summarized as:

- Construction period: 2023 – 2027 (tentative)
- Operation period: 2027 – 2067 (40 years)
- Decommissioning: after 2067

This document provides information to satisfy the requirements of the Strategic Assessment of Climate Change (SACC) and the associated draft Technical Guide Related to the Strategic Assessment of Climate Change (the draft Technical Guide). An assessment of carbon sinks is provided in Section 2.0. An upstream greenhouse gas (GHG) assessment, including an estimate of upstream GHG emissions and a discussion about the incrementality of those emissions, is provided in Section 3.0. A Best Available Technology (BAT)/Best Environmental Practice (BEP) assessment is provided in Section 4.0 and the net-zero plan is provided in Section 5.0. A climate resilience assessment is provided in Section 6.0.

2.0 CARBON SINKS

2.1 INTRODUCTION

In the context of building a new facility, such as the Project, carbon sinks are places in the environment (natural or human made) where carbon from the atmosphere is stored and builds up over time. An example is the biomass contained in the vegetation (such as trees or shrubs) that is growing in an area of land. Changes in land-use can result in changes to the carbon sinks. This occurs most noticeably when projects change existing forest land, cropland, wetland, and grassland to the developed ("settlement") land type, as defined by IPCC (IPCC 2019). The SACC requires proponents to qualitatively and quantitatively describe how a project will modify the land's natural absorption of carbon from the atmosphere. As per the draft Technical Guide (ECCC 2021a), only lands that are considered to be Forest Land or Wetland are included in the quantification of the change in carbon absorption.

The draft Technical Guide describes the methodology to be used when quantifying the change to carbon sinks. Stantec used Equation 5 from the draft Technical Guide to estimate the carbon sink impact (CSI):

$$CSI = \sum_{i,j} \left((NatFlux - PostDFlux)_{i,j} \right) \times T_{i,j} \times A_{i,j}$$

Where NatFlux is the natural annual carbon accumulation rate of the land (t C/ha/y), PostDFlux is the post-disturbance flux rate (t C/ha/y), i is the land use class, j is the disturbance activity, t is the time interval (year), and A is the land area (ha).

2.2 SITE SPECIFIC DATA

2.2.1 Land Use Class

The existing land within the Project footprint includes land with vegetation, rivers, lakes, and wetlands. The British Columbia Land Class System (BCLCS) was used to categorize the land into the following land classes:

- Upland
  - Tree, coniferous (dense, sparse, and open)
  - Tree, broadleaf (dense)
- Wetland
  - Tree, coniferous (sparse)

Table 1 shows the areas of each land class and the categorizations used for the carbon sink assessment.

Table 1 Land Class Description and Areas

BCLCS Description	Total Area in Project Footprint (ha)	Draft Technical Guide Categorization
Upland, tree, coniferous	31.3	Forest Land
Upland, tree, broadleaf	0.2	Forest Land
Wetland, tree, coniferous	0.1	Forest Land
Total	31.6	Forest Land

NOTES:
Only areas that are planned to be cleared have been included. Approximately 3.2 ha of land within the footprint has been excluded as it will not be cleared and the Project will not change the carbon sink capacity of this area.
Totals may not add up due to rounding.
SOURCE: FLNRORD 2021

Although the BCLCS defines a portion of the area as wetland, a small portion of that area contains trees and, therefore, has been added to the Forest Land category.

2.2.2 Natural Flux

The natural flux in a forest is the annual carbon accumulation rate that exists due to the growth of trees. Trees steadily accumulate carbon until they reach maximum carrying capacity (MCC), after which point the rate of carbon uptake is approximately balanced by the amount of carbon lost through decay of dead organic matter. Trees that have not reached the MCC point have the potential to continue to sequester carbon from the atmosphere.

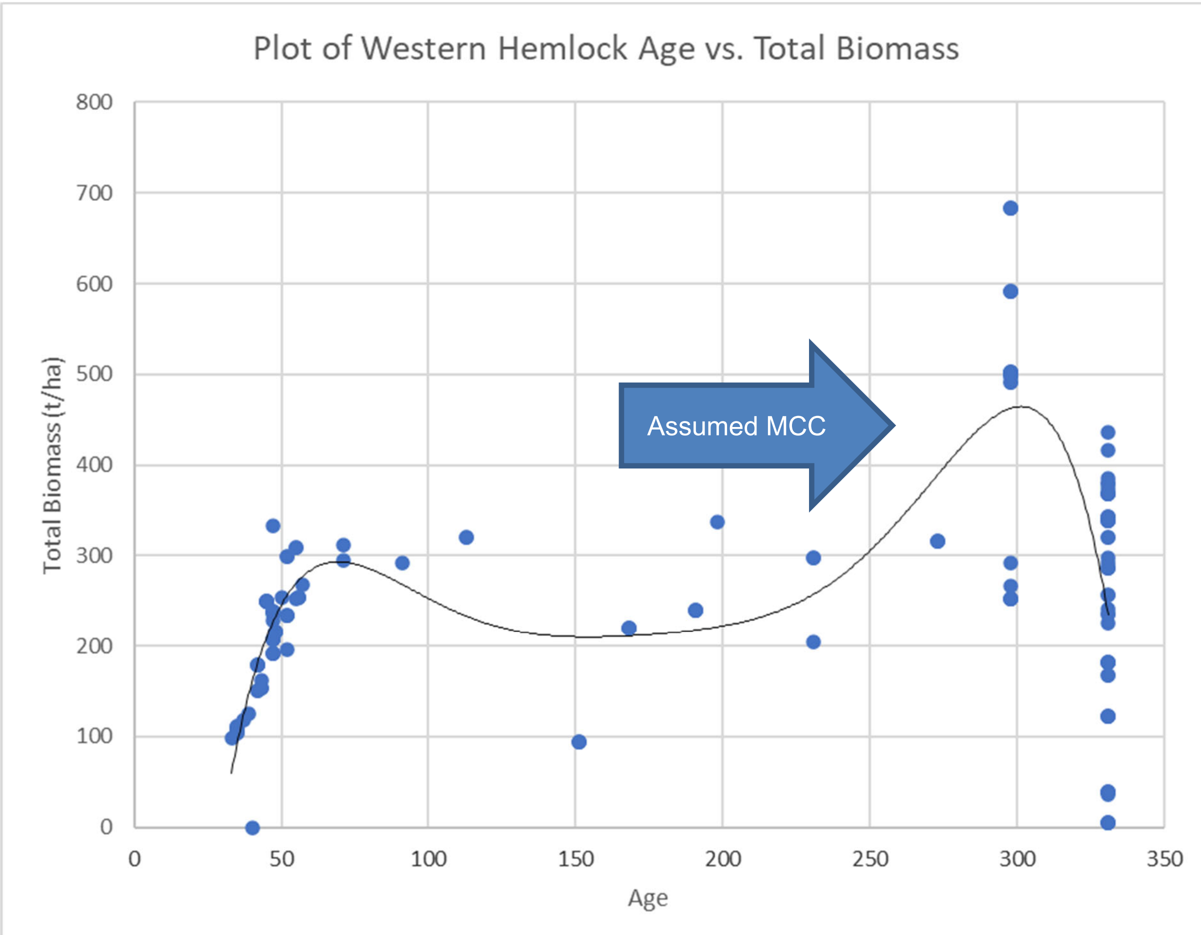
Stantec calculated the Natural Flux of the existing Forest Land using Equation 6 from the draft Technical Guide:

$$NatFlux_{Forest} = \frac{BM_{MCC} - BM_{Current}}{Age_{MCC} - Age_{Current}}$$

Where BMMCC is the living tree biomass at maximum carrying capacity (t C/ha), BMCurrent is the living tree biomass at the forest stand's current age (t C/ha), AgeMCC is the age at which MCC is reached, and AgeCurrent is the current age of the forest.

On the 31.6 ha of Forest Land, the tree species present are: amabalis fir (2 ha), red alder (0.2 ha), and western hemlock (29.4 ha) (FLNRORD 2021). The age of the trees ranged from approximately 35 to 334 years old. The draft Technical Guide did not provide the MCC of amabilis fir, red alder, or western hemlock in British Columbia. However, age and biomass information can be obtained from the BCLCS (FLNRORD 2021). The BCLCS has biomass information on the stem, foliage, bark, and branch; Stantec used the biomass and age information from the BCLCS for the western hemlock to identify the age and total above-ground biomass where biomass growth appears to plateau; this plot can be seen in Figure 1.

Figure 1 Plot of Western Hemlock Age vs. Total Biomass



Based on this analysis of 154 records from BCLCS (FLNRORD 2021), the MCC for Western Hemlock occurs at about 298 years of age and the average total biomass at this age is 470 tonnes of above-ground biomass per hectare on a wet basis. There were only a few records from the BCLCS for the amabilis fir and red alder in this particular ecoregion, such that a similar analysis could not be done for those species. Stantec, therefore, chose to apply the estimated western hemlock MCC information to the land area dominated by amabilis fir and red alder. Given the small land area where amabilis fir and red alder are present (2.2 ha, or 7% of cleared area), this approximation is considered reasonable.

For each stand, Stantec calculated the total above-ground biomass including the stem, bark, foliage, and branches. The below-ground biomass (e.g., roots) was estimated from applying a 20% factor to the above-ground biomass based on available information (Trees for the Future n.d.). The total tree biomass was then reduced by 27.5% to account for moisture (Trees for the Future n.d.) and finally a 50% carbon percentage of dry tree was applied to establish the tonnage of carbon per hectare. The result is that biomass at MCC for the western hemlock is approximately 204 t C per ha when accounting for moisture, below-ground biomass, and carbon content.

Stantec estimated the term AgeMCC – AgeCurrent following guidance in the draft Technical Guide. In cases where the existing forest stand age was greater than the age at MCC (298 years of age), the natural flux was not calculated as the change in carbon sink would have resulted in a carbon source, rather than a carbon sink; this approach is consistent with the draft Technical Guide. In all other cases, the stand ages in the footprint were either at or more than 100 years from the age at MCC; because the assessment is limited to a 100-year period, the AgeMCC – AgeCurrent term was set at 100 years (as per the draft Technical Guide).

2.2.3 Disturbance Activity

For the carbon sinks assessment, Stantec assumed that for all Forest land, the Project will completely interrupt the carbon sink capacity of the land. It follows, therefore, that the land within the Project footprint shown in Table 1 will have a PostDFlux of 0 t C/ha/y. This approach is consistent with the default assumption shown in Annex D of the draft Technical Guide and it is intended to be conservative.

2.3 RESULTS

The estimated values of the CSI for each tree species are presented in Table 2.

The total CSI for cleared area associated with the Project is 1,741 t C, which is equivalent to 6,384 t CO_2, assuming that all lost carbon is oxidized to carbon dioxide (as per the draft Technical Guide).

2.4 ASSUMPTIONS AND LIMITATIONS

The methodology used to estimate the CSI is the approach described in the draft Technical Guide. Stantec used estimated age and biomass tonnages of trees from the BCLCS, as well as assumptions about moisture content, below-ground biomass, and carbon content to estimate CSI.

Where there was insufficient information to establish the MCC age and biomass tonnage for red alder and amabilis fir, Stantec applied the estimated MCC age and biomass tonnage for western hemlock to areas dominated with red alder and amabilis fir. Given the small area occupied by red alder and amabilis fir, this approach is reasonable. Based on Table 34 in the draft Technical Guide, the age at MCC for deciduous species such as red alder tends to be less than 100 years; therefore, Stantec has conservatively included more biomass in the CSI than what is likely present.

Table 2 Carbon Sink Impact

Tree Species	Average $BM_{Current}$ (t C/ha)	BM_{MCC} (t C/ha)	Average $Age_{Current}$ (year)	Age_{MCC} year)	Average Natural Flux (t C/ha/y)	PostDFlux (t C/ha/y)	Area (ha)	Total CSI (t C)
Red Alder	87.2	204	41	298	-2.04	0	0.2	-25.3
Amabilis Fir	67.7	204	331	298	Positive	0	2	Not included
Western Hemlock	108	204	213	298	-1.42	0	27.4	-1,716
Total								-1,741

3.0 UPSTREAM ASSESSMENT

3.1 INTRODUCTION

This section is provided to satisfy the federal requirements outlined in the SACC guideline by Environment and Climate Change Canada ECCC (2020) to assess upstream greenhouse gas (GHG) emissions associated with the Cedar LNG Project (the Project).

Upstream GHG emissions are considered to be emissions (domestic and non-domestic) from all stages of production, from the point of resource extraction or utilization to the Project under review. This is interpreted to include emissions for production, processing, and transmission of the natural gas to the Project.

In accordance with the instructions outlined in the draft Technical Guide, this report has been divided into two parts. Section 3.2 covers "Part A", the quantitative estimation of the GHG emissions released as a result of the upstream activities associated with the Project. Section 3.3 of this report addresses "Part B", the requirement to provide a qualitative discussion of the incrementality of upstream GHG emissions.

3.2 PART A - ESTIMATION OF UPSTREAM GREENHOUSE GAS EMISSIONS

3.2.1 Upstream Activities and Products

The Project will process and liquefy approximately 400 million standard cubic feet per day (11.3 million cubic metres [m^3]) of natural gas sourced from northeastern British Columbia. The activities upstream of the Project include natural gas extraction, production and processing, and natural gas transmission to the Project.

In accordance with the draft Technical Guide, land use changes, exploratory drilling, manufacturing of equipment and material, and construction of infrastructure on site are excluded from the estimate of upstream emissions. Generation of purchased electricity used by the Project is also excluded from the upstream emissions as it is included in the Project emissions under the category of acquired energy.

3.2.2 Possible Scenarios

As discussed in Section 1.5.6 of the Application, Cedar intends to receive feed natural gas from Coastal GasLink at an interface point near the LNG Canada Export Terminal in Kitimat. Coastal GasLink will transport gas from an area near the community of Groundbirch, approximately 40 km west of Dawson Creek, British Columbia. Therefore, activities upstream of the Project will be located entirely in northeast British Columbia, with no international contribution of GHG emissions.

The capacity of the Project is 400 million standard cubic feet per day (11.3 million m3 per day), which will produce approximately three million tonnes of LNG annually. The upstream GHG assessment presented herein is provided for the operating capacity.

Although a project may evolve over its operation phase, and the sources and quantities of feedstock may vary, at this time, there are no alternatives to pipelines to cost-effectively move large amounts of natural gas over land from producing regions to consuming regions. Therefore, Cedar requires firm delivery of natural gas via pipeline. As there are no natural gas delivery pipelines proposed or under development that could transport gas to the Project, we do not speculate about the location of upstream activities other than those occurring in northeastern BC.

3.2.3 Upstream GHG Emission Intensities

Upstream GHG emission intensities for natural gas production and processing and natural gas transmission have been taken from Tables 35 and 36 of the draft Technical Guide (ECCC 2021a), respectively. Emission intensities between 2027 and 2030 have been used directly. After 2030, it is assumed that emission intensities are the same as 2030. Although the Project is expected to operate for 40 years, upstream emissions were calculated until 2050, per the draft Technical Guide (ECCC 2021a). Emission intensities used in the upstream GHG calculation are presented in Table 3.

Table 3 Upstream GHG Emission Intensities

Upstream Activity	Unit	Year			
		2027	2028	2029	2030 [a]
Natural Gas Production and Processing	kg CO_2e/bbl eq	30.7	30.7	30.5	30.3
Natural Gas Transmission	kt CO_2e/bcf	1.42	1.41	1.40	1.38

NOTE:
[a] Emission intensities for 2030 were used for 2031 – 2050.

According to the draft Technical Guide (ECCC 2021), the stated natural gas production and processing intensities are:

> "based on ECCC's Energy, Emissions and Economy Model for Canada which was developed using the 2020 National Inventory Report and were calculated as a ratio of total forecasted GHG emissions and the projected levels of production for each Oil and Gas sub-sector. Total GHG emissions included in this calculation are from sources such as combustion, fugitives, sequestration, and cogeneration. Moreover, ECCC's Oil and Gas production forecast is aligned to the Canada Energy Regulator's 2020 Energy Future report's Reference Scenario projections.

The natural gas transmission intensities were calculated using the total forecasted GHG emissions associated with transmission divided by the national amount of product transported based on the Statistics Canada Table 25-10-0058-01. To develop projections for the national amount of product transported, the production projection trends were used."

3.2.4 Results

Annual upstream GHG emissions were calculated using Equation 7 from the SACC draft Technical Guide:

$$Annual\ Product\ Upstream\ GHG\ Emissions = \sum_{j}^{n} EI_j\, xPROD_j$$

Where j is the distinct activity for the product, n is the total number of activities for the product, EIj is the emission intensity of the activity identified and PRODj is the annual upstream production associated with activity j.

For this calculation:

- j = natural gas production and processing; natural gas transmission
- n = 2
- EI, = see the emission intensities provided in Table 4
- $Prod_j$ = 24,955,692 bbl eq; 146 bscf feed gas per year

Table 4 presents annual upstream GHG emissions associated with the Project between 2027 and 2050. Total annual emissions range between 975 and 959 kt CO_2e per year, with 79% of the upstream emissions attributable to production and processing activities.

Using an annual LNG production of 3 MTPA, the upstream emission intensity is approximately 0.32 t CO_2e/t LNG after 2030.

Table 4 Annual Upstream GHG Emissions

Year	Upstream Emissions ($kt\ CO_2e$)			Upstream Emission Intensity ($t\ CO_2e$ / t LNG)
	Production and Processing	Transmission	Total	
2027	767	207	975	0.33
2028	767	206	973	0.32
2029	762	204	967	0.32
2030	757	201	959	0.32
2031	757	201	959	0.32
2032	757	201	959	0.32
2033	757	201	959	0.32
2034	757	201	959	0.32
2035	757	201	959	0.32
2036	757	201	959	0.32
2037	757	201	959	0.32
2038	757	201	959	0.32
2039	757	201	959	0.32
2040	757	201	959	0.32
2041	757	201	959	0.32
2042	757	201	959	0.32
2043	757	201	959	0.32
2044	757	201	959	0.32
2045	757	201	959	0.32
2046	757	201	959	0.32
2047	757	201	959	0.32
2048	757	201	959	0.32
2049	757	201	959	0.32
2050	757	201	959	0.32

3.2.5 Assumptions and Limitations

Part A of the upstream GHG assessment follows the methods suggested in the draft Technical Guide (ECCC 2021a) and the assessment limitations are, therefore, consistent with the limitations contained therein. Key assumptions are:

- ECCC-provided emission factors are available until 2030. Annual upstream emissions after 2030 were assumed to be the same as 2030
- All upstream emission sources were assumed to be domestic
- Consistent with the required methodology, the assessment focused on direct GHG emissions from upstream activities assumed to be associated with the Project including production, gathering, and processing of natural gas. Indirect upstream emissions were excluded.
- The assessment does not consider future changes to upstream emissions that may be driven by technology improvements or mitigation techniques

3.3 PART B – QUALITATIVE DISCUSSION ON THE INCREMENTALITY OF UPSTREAM EMISSIONS

3.3.1 Introduction

The draft Technical Guide (ECCC 2021) identifies the following requirements for Part B of the upstream GHG assessment:

- Scenario analysis of project alternatives, including at least one scenario where the Project is not built and a scenario where the Project is built.
- Provide technical and economic information to discuss market and infrastructure assumptions that could result in incremental emissions and support assumptions used in the scenario analysis with credible references.
- Discuss potential impact of upstream GHG emissions on Canada's overall GHG emissions.
- Assess relationship between production and emissions in Canada, including how policy changes could affect upstream emissions over time.
- Discuss potential impact of incremental upstream production on global emissions.

The following sub-sections sequentially apply the guidance provided in the draft Technical Guide to present the potential impact of the upstream emissions associated with the Project on Canadian and global GHG emissions. As part of this analysis, this section assesses the extent to which the upstream GHG emissions estimated for the Project in Section 3.0 are incremental (i.e., could occur even if the Project was not built).

3.3.2 Natural Gas Production and Market

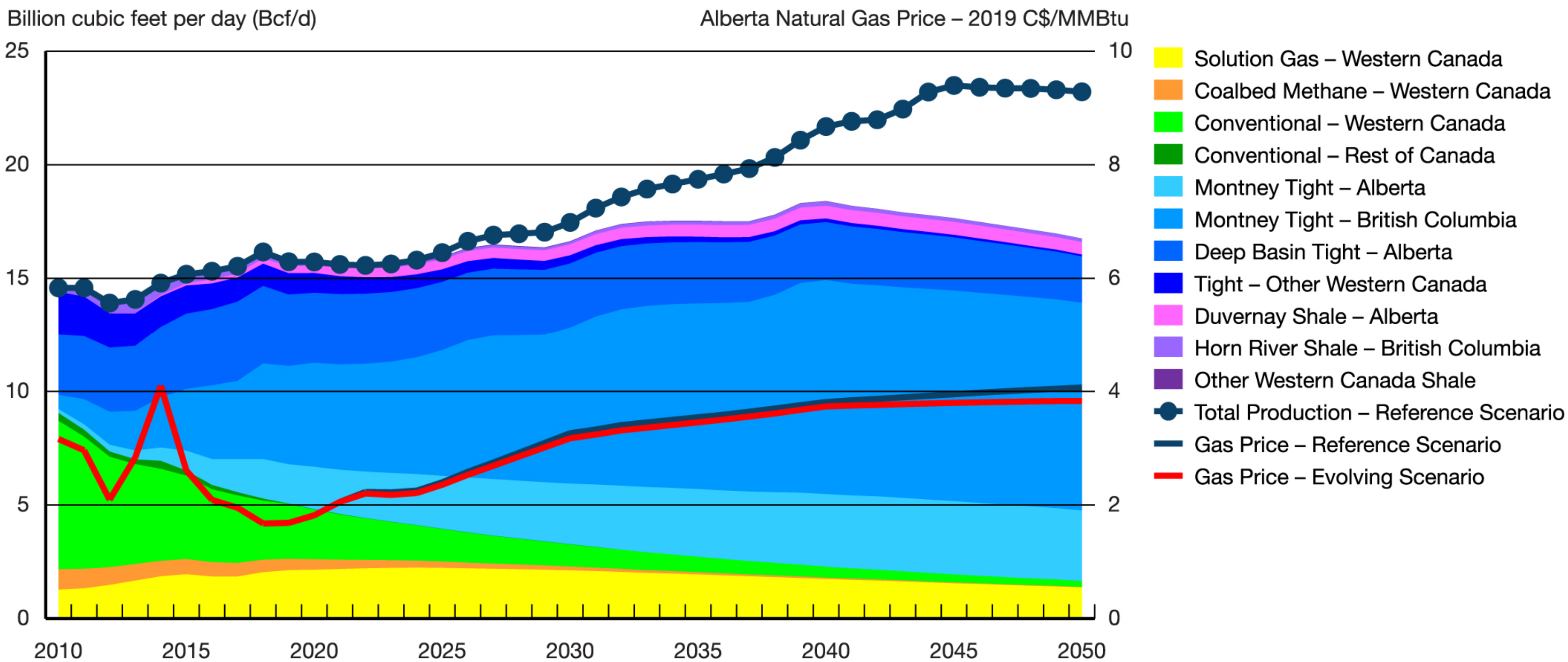
3.3.2.1 Canadian Natural Gas Production

The Canada's Energy Futures Report 2020 (EF2020) is the most recently released publicly available information from the Canada Energy Regulator (CER) for Canada's energy supply and demand through 2050, including natural gas production forecasts in Canada and can thus be used to support evaluation of overall upstream natural gas production expected. The report and analysis are prepared by the CER. The EF2020 uses economic and energy models to make projections about the long-term energy outlook in Canada. The projections are based on assumptions about future trends in technology, energy and climate policies, energy markets, human behaviour and the structure of the economy (CER 2021).

The EF2020 presents two scenarios of potential outcomes for the Canadian energy system over the next 30 years. These scenarios are the Evolving Energy System Scenario (Evolving Scenario) and the Reference Energy System Scenario (Reference Scenario). These scenarios provide energy supply and demand projections that differ based on the level of future action to reduce GHG emissions. The difference in the premise between these two scenarios impacts their specific assumptions – such as crude oil prices and renewable energy costs – which drive the supply and demand projections. The core premise of the Evolving Scenario is that action to reduce the GHG intensity of our energy system continues to increase at a pace similar to recent history, in both Canada and the world. This evolution implies less global demand for fossil fuels, and greater adoption of low carbon technologies. In contrast, the Reference Scenario assumes limited additional action to reduce GHGs beyond those policies in place today, implying higher demand for fossil fuels and less adoption of low carbon technologies. Consistent with these implications, in the Evolving Scenario lower international prices for fossil fuels and a higher pace of technological change over the projection period are assumed, compared to the Reference Scenario (CER 2021).

The EF2020 also includes a discussion of even greater climate action, in the "Towards Net-Zero" section. The "Towards Net-Zero" section does not provide a projection of the future natural gas forecasts under a Net-Zero directed economy, but rather a discussion of some of the key issues in transitioning towards a net-zero energy system. Because Canada has now made a commitment to achieve net-zero GHG emissions by 2050, as have all the G7 countries, it is expected that the natural gas production presented in the Reference Scenario is on the high side and the Evolving Scenario projections could also be on the high side. These are nonetheless the most recent available Canadian data and are useful in putting Project production requirements in context. The International Energy Agency Net Zero Report (IEA 2021) is also discussed in Section 3.3.2.3 in relation to potential global natural gas demand under a net zero by 2050 scenario.

Figure 2 Marketable Natural Gas Production-Evolving Scenario (CER 2021)



In the Evolving Scenario, natural gas production from new wells is just enough to keep pace with the declining production from existing wells in the near term. As a result, total production is essentially level until 2025. In the longer term, rising prices and the onset of LNG exports support higher capital expenditure and production growth. Tight gas (gas from more impermeable formations) continues to have an increasing share of production, while conventional production continues declining. The Evolving Scenario assumes lower gas prices, higher carbon costs, and lower LNG exports than the Reference Scenario.

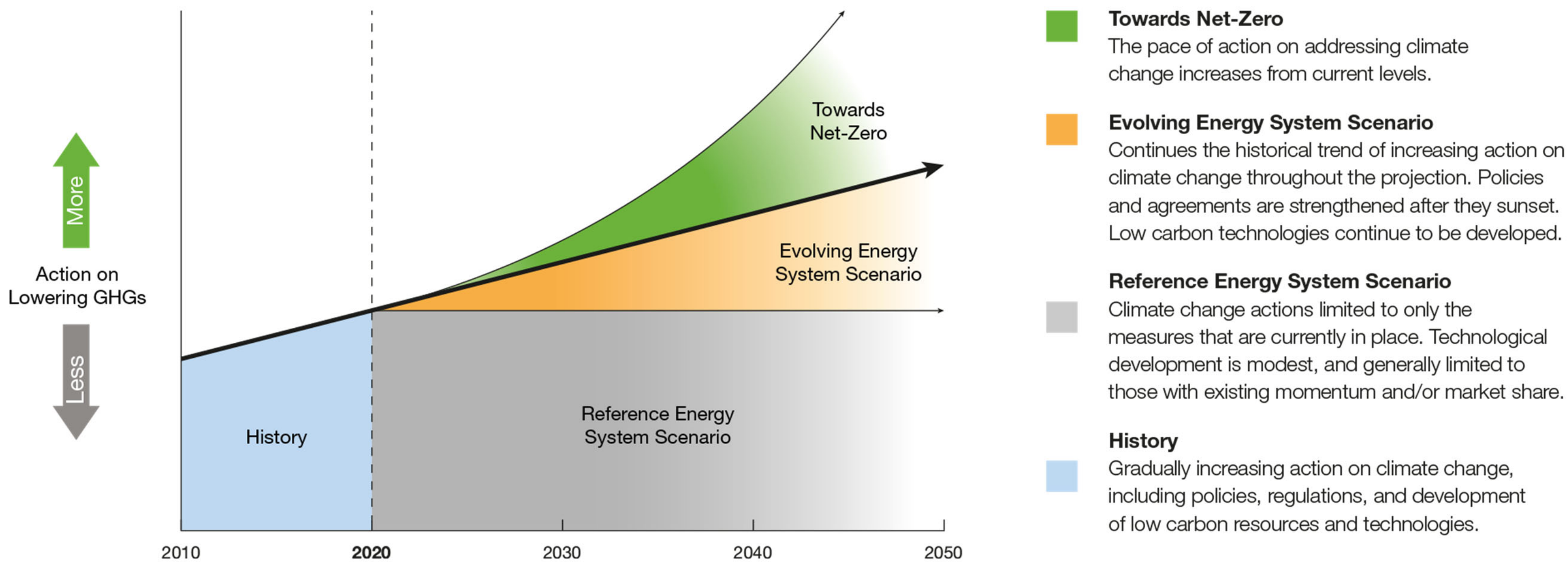
Under the Evolving Scenario, LNG exports are estimated to be 2.3 bcf/d by 2030 and increasing to 4.9 bcf/d by 2040 and holding at that level to 2050. At 400 million cf/d (0.4 bcf/d), the Project would represent approximately 17% of Canada's export forecast in 2030. This CER study concludes that in the longer term, additional production for LNG exports keeps total production in Canada above current levels.

3.3.2.2 Market Demand Drivers

A key market driver is expected to be the pace of action to decarbonize the global economy. As depicted in the EF2020 report, the requirements of net-zero achievement by 2050 will accelerate GHG reduction initiatives including reduction in oil and gas consumption (and thus reduced demand would occur).

As the gas produced in British Columbia and the Project itself have access to low carbon hydroelectric with potential for relatively low GHG intensities and the gas already has a price on carbon emissions attached to it, demand for this gas may increase as buyers become more climate conscious and new GHG regulations such as border carbon adjustments are implemented.

Figure 3 Pace of Action on Lower GHGs in Differing Energy System Scenarios CER 2021)



3.3.2.3 Global LNG Production/Outlook

The Gas Exporting Countries Forum (GECF or Forum) is an intergovernmental organisation established in May 2001 in Tehran, Islamic Republic of Iran. The GECF most recently published the Global Gas Outlook 2050 (in 2020), which provided forecasts for global gas supply and demand out to 2050 (GECF 2020).

According to the most recent GECF report, fossil fuels will maintain a leading role in the global energy mix, accounting for 71% in 2050 (compared to 81% in 2019). Natural gas will be the only hydrocarbon resource to increase its share from the current 23% to 28% in 2050. Simultaneously, the structure of the energy mix will become more diversified thanks to the progress in renewables with its share of the global energy mix to quintuple to 10% by 2050. This report indicates that natural gas is an indispensable fuel, complementing the energy transition. Contributing 48% to the global growth in energy demand, natural gas overtakes coal in 2025 and becomes the largest energy source by 2047, with oil plateauing around 2040 and then beginning an irreversible decline.

Natural gas demand is projected to rise by 50% from 3,950 bcm in 2019 to 5,920 bcm in 2050, boosted by cumulative economic and population drivers, environmental concerns, increasing availability of supplies and positive policy support in many countries. This abundant, flexible, and relatively clean (as compared to other fossil fuels) source of energy is expected to expand specifically across the Asia Pacific, North America and Middle Eastern markets, which will be responsible for more than 75% of the total gas demand growth by 2050. The Asia-Pacific region will become the largest gas consumer, doubling consumption to 1,660 bcm by that date.

Power generation and industry are projected to be the main areas of gas demand expansion, together accounting for more than 70% of additional volumes. The power generation sector will represent the largest growth engine thanks to the strong rise in electricity demand and policies supporting the phase-out of coal-fired capacity (GEFC 2020).

The International Energy Agency (IEA) released a Net Zero by 2050 Roadmap in 2021 which provides further forecasts on natural gas use globally out to 2050 (IEA 2021). The net zero emissions scenario presented in this report indicates a major contraction of oil and gas production with natural gas demand falling to around 1,700 bcm by 2050 (71% lower than the GEFC 2050 forecast). This report highlights that the global pathway to net-zero emissions by 2050 detailed requires all governments to significantly strengthen and then successfully implement their energy and climate policies. Commitments made to date fall far short of what is required to attain net zero emissions globally and most pledges are not yet underpinned by near-term policies and measures.

The project is expected to provide approximately 4 bcm per year to the international market. In consideration of the GECF forecast, the Project would provide approximately 0.07% of global demand while if the much lower IEA forecast under a net zero scenario is applied, the project would supply 0.2% of global demand.

Whether the forecasted surge in natural gas demand comes to fruition or not, Project upstream emissions are not expected to be incremental on a global scale. Even under the net zero scenario, the Project is a small fraction of global demand and it is expected that if the Project did not proceed, an equivalent amount of natural gas production would occur elsewhere in the world to meet the global demand. As the GHG emissions from production of natural gas in British Columbia are regulated, it is possible that if the Project did not proceed, a higher GHG intensity production source may meet the market demand that would be filled by this Project.

3.3.3 Scenario Analysis

ECCC 2021a requires a scenario analysis of project alternatives, including at least one scenario where the Project is not built and a scenario where the Project is built. The only project alternative being considered is the No Project Case alternative or not proceeding with the project. As the Evolving Scenario and Reference Scenarios in CER 2021 indicate, Canada's natural gas production would need to increase to service the export market. Therefore, the upstream GHG emissions from production of natural gas within Canada should be considered incremental to what would occur if the Project were not to occur. Globally, the emissions are not expected to be incremental as if the project did not occur, it is expected another similar project would supply the need.

Canada's GHG emissions forecasts in 2030 as per the March 2021 report on progress toward targets (ECCC 2021c) indicate that based on the measures in the Pan-Canadian Framework, other announced provincial/territorial measures, and the new measures in under Canada's strengthened climate plan, national emissions are projected to be 503 Mt CO_2e in 2030.

Assuming the Project's upstream emissions are fully incremental, the upstream emissions of 0.959 Mt CO_2e would contribute 0.2% to Canada's 2030 emissions. As Canada continues toward a net zero by 2050 target, it is assumed that Project upstream emissions would need to decline to meet tightening legislation on GHG emissions. Globally, the influence of Project upstream emissions are expected to be negligible.

4.0 BEST AVAILABLE TECHNOLOGY AND BEST ENVIRONMENTAL PRACTICES DETERMINATION

The objective of this BAT/BEP determination is to illustrate how Cedar has considered existing and emerging technologies and practices in the design and planning of the Project.

The process for conducting a BAT/BEP determination follows the draft Technical Guide (ECCC 2021) and includes:

1. List all available and emerging technologies and practices that are relevant to the Project
2. Conduct technical feasibility assessment
3. Conduct GHG reduction potential assessment
4. Conduct economic feasibility assessment
5. Consider any other factors that affect BAT/BEP determination
6. Select BAT/BEP

4.1 RELEVANT PROJECT DETAILS

The Project consists of three main components: the floating LNG facility (FLNG facility), the marine terminal, and the supporting infrastructure. The FLNG facility includes equipment for gas treatment, LNG production, LNG storage, and related infrastructure. Pipeline quality feed gas is the input to the FLNG facility. The marine terminal includes the infrastructure designed to permanently moor the FLNG facility and provide connections to land-based natural gas and power supplies. LNG carriers visiting the Project will berth directly alongside the FLNG facility for side-by-side loading. Additional details on the Project description can be found in Section 1.0 of the Application.

The Application includes the assessment of the construction, operation, and decommissioning phases of the Project. Construction of the Project includes site preparation and construction of the marine terminal and supporting infrastructure, including the electricity transmission line. The FLNG facility will be built in a shipyard in Asia and transported to the marine terminal for installation and commissioning. It is therefore not included in the assessment of construction impacts. Emissions from site preparation and construction activities are associated with the use of heavy off-road construction equipment, such as excavators and cranes, as well as marine equipment. Some blasting may also be required.

During the operation phase, the Project requires energy to treat and liquefy the gas, operate ancillary equipment, support personnel (e.g., comfort heating), and transport the LNG to market. Stationary combustion equipment (heater, boiler, oxidizer, pumps, generator), flares, electricity supply, and marine vessels are used during the operation phase.

At the end of the Project's lifetime, the Project is decommissioned. Decommissioning activities are similar to construction activities and use similar types of off-road construction equipment.

Additional details on the activities during the construction, operation, and decommissioning phases activities can be found in Section 1.0 of the Application.

4.2 TECHNOLOGIES AND PRACTICES

Stantec identified the established and emerging technologies and practices available to meet the energy needs of the Project during the construction, operation, and decommissioning phases. The technologies considered in the BAT Determination process are presented in Table 5. Note that the BAT Determination is only required for equipment that is anticipated to produce 1% or more of the total GHG emissions from the Project; other equipment have been excluded from Table 5 (e.g., firewater pumps). Details on the GHG emissions from emission sources can be found in the Greenhouse Gas Emissions Technical Data Report submitted under separate cover.

Table 5 List of Best Available and Emerging Technologies

Phase/Year	Source	Available Technologies	Emerging Technologies
Construction	On-land equipment	• Diesel fueled • Biodiesel fueled • Renewable diesel	• Electric (battery) • Hydrogen-based electric • LNG fueled
	Marine equipment	• Marine diesel oil • Dual fuel diesel/LNG • Electric (battery)	• None
Operations	Acquired energy	• Connection to B.C. electricity grid with back-up diesel generators on-site • Combined cycle gas-turbine on-site • Wind energy • Solar energy • Steam turbine with biomass combustion on-site	• None
	Regeneration gas heater	• Natural gas liquid combustion • Electrified equipment • Waste heat from combined cycle gas turbine system	• None
	Auxiliary boiler	• Natural gas liquid combustion • Electrified equipment • Waste heat from combined cycle gas turbine system	• None
	Acid gas containing CO_2	• Thermal oxidizer with natural gas combustion to support • Flare with natural gas combustion to support	• Carbon capture and storage prior to oxidizer • Carbon capture and usage prior to oxidizer

Table 5 List of Best Available and Emerging Technologies

Phase/Year	Source	Available Technologies	Emerging Technologies
Operations (cont'd)	Disposal of natural gas for maintenance, upset, emergency	• Flaring • Thermal oxidizer • Vapour recovery unit	• None
	LNG carriers in transit	• Dual fuel boil-off gas and marine gas	• None
	LNG carriers at terminal	• Dual fuel boil-off gas and low sulphur marine gas • Shore-based electricity	• None
	Tugboat at terminal	• Distillate marine gas oil • Dual fuel diesel/LNG • Electricity (battery) with fossil fuel back-up	• None
Decommissioning	On-land equipment	• Diesel fueled • Biodiesel fueled • Renewable diesel	• Electricity (battery) • Hydrogen-based electric • LNG fueled
	Marine equipment	• Marine diesel oil • Dual fuel diesel/LNG • Electric (battery)	• None

4.2.1 On-land and Marine Equipment

The expected equipment during the construction phase includes traditional on-land construction equipment, such as bulldozers and excavators, as well as piling rigs, a crane, a feller buncher, and a rock drill. Tugboats and a spud barge are also expected to be used. The construction activities are associated with the marine terminal construction and transmission line clearing. At decommissioning, similar equipment would be used.

The construction and decommissioning equipment units are assumed to be owner-operated under a maintenance and repair contract. Fleet maintenance activities will be performed either at the Project site or at the owner's maintenance facilities.

Three available technologies and three emerging technologies were considered in this assessment.

4.2.2 Acquired Energy

Three options to provide energy at the source of the stationary equipment have been considered: electricity, diesel combustion, and natural gas combustion. For energy to power other equipment, such as lighting, compressors, and motors, an assessment of electricity generation options can be found in the Acquired Energy section.

4.2.3 Regeneration Gas Heater and Auxiliary Boiler

The Project requires heat to regenerate the dehydration beds and to regenerate the amine system that is used to capture CO_2 and H_2S. Both natural gas liquid combustion and heat generated from electricity were considered.

4.2.4 Acid Gas Containing CO_2

The acid gas stream consists mostly of CO_2 with some sulphur compounds. Two existing destruction technologies were considered. In addition, the possibility of CO_2 capture and either usage or storage was considered.

4.2.5 Disposal of Natural Gas for Maintenance, Upset, and Emergencies

From time to time, the Project will need to remove natural gas from equipment. Venting natural gas directly is not considered as this poses health and safety risks to personnel and the environment. Two destruction options and one recovery option are considered.

4.2.6 LNG Carriers in Transit and at Berth

LNG carriers have specialized pumping and storage systems designed for the safe and efficient transport of LNG. One established technology was considered.

Once docked, an LNG carrier continues to require energy for safety systems and personnel comfort. Two available energy sources were considered.

4.2.7 Tugboats at Terminal

The tugboats will be operating both the main propulsion engine and the auxiliary engine while stationed at the terminal to assist with maneuvering. Two available energy sources and one emerging energy source were considered.

The practices considered in the BEP Determination process are presented in Table 6.

Table 6 List of Available and Emerging Practices

Phase/Year	Source	Available Practices	Emerging Practices
Construction	Carbon sinks	• Biomass burning • Biomass chipping and spreading • Decomposition • Site remediation • Merchantable timber recovery	• None
	On-land equipment	• Anti-idling policy • Optimal sizing • Regular maintenance • Preference for contractors with newer (more efficient) fleets • Traffic management plan (e.g., bussing)	• None
Construction (cont'd)	Marine equipment	• Optimal sizing • Regular maintenance • Energy efficiency measures	• None
Operations	Acquired energy	• Energy efficiency measures • Regular maintenance of equipment (on-site only) • Measurement of electricity consumption	• None
	Regeneration gas heater	• Energy efficiency measures • Fuel monitoring • Regular maintenance • Optimal sizing	• None
	Auxiliary boiler	• Energy efficiency measures • Fuel monitoring • Regular maintenance • Optimal sizing	• None
	Acid gas containing CO_2	• Optimal sizing • Fuel monitoring • Regular maintenance • Energy efficiency measures	• None
	Disposal of natural gas during maintenance, upset, and emergencies	• None	• None
	LNG carriers in transit	• None	• None
	LNG carriers at terminal	• None	• None
	Tugboat at terminal	• None	• None

Table 6 List of Available and Emerging Practices

Phase/Year	Source	Available Practices	Emerging Practices
Decommissioning	Carbon sinks	• Site remediation	• None
	On-land equipment	• Anti-idling policy • Optimal sizing • Regular maintenance • Preference for contractors with newer (more efficient) fleets • Traffic management plan (e.g., bussing)	• None
	Marine equipment	• None	• None

4.3 TECHNICAL FEASIBILITY ASSESSMENT

4.3.1 On-Land and Marine Equipment During Construction and Decommissioning

4.3.1.1 Diesel

Construction equipment that is commercially available in Canada are fuelled with diesel derived from crude oil. The diesel is typically trucked to sites in bulk and stored in tanks before being used. A diesel engine combusts diesel with air in a compression-ignition engine. The combustion of diesel fuel releases GHGs and air contaminants, such as nitrogen oxides, into the atmosphere.

The use of diesel-fueled construction equipment is well established in many sectors and is in use throughout the world. Regulatory requirements and best operational practices for diesel storage and fuelling technologies are well defined in Canada. Diesel trucks sold for use in Canada are designed to meet the health and safety, fire and life safety, and air pollution control requirements in Canada. There would be very low risk associated with the use of diesel-fueled equipment. Manufacturers offer a wide variety of equipment in a range of sizes, which makes it easier for users to find equipment that best suits the conditions and tasks.

The use of diesel fuel in construction equipment during the construction phase is technically feasible. Assuming that diesel remains commercially available and manufactured construction equipment still uses liquid fuels once decommissioning begins, diesel fuel would be technically feasible in the decommissioning phase.

4.3.1.2 Marine Diesel

During construction and decommissioning, one spud barge and up to eight tugboats are expected to support the construction and installation of the FLNG. Marine diesel and marine gas engines are commonly used in marine vessels and are technically feasible to implement in the construction phase.

By 2023, the HaiSea Marine Limited Partnership (HaiSea Marine) plans to build and operate two dual fuel (LNG and diesel) and three electric (battery) tugboats to serve the LNG Canada project (Seaspan 2021). The delivery of these tugboats is planned for 2023. The technologies are currently commercially available and technically feasible to operate, provided LNG fuelling and shore-side electricity supply is available to service the tugboats.

4.3.1.3 Biodiesel Blend

Canada's Renewable Fuels Regulation was amended in 2011 to mandate that 2% of diesel sold in Canada must be renewable. The B2 biodiesel blend is commercially available at diesel filling stations in British Columbia. Although there are two biodiesel manufacturing facilities in Delta, British Columbia, the majority of British Columbia's biodiesel is imported from the United States (British Columbia Sustainable Energy Association (BCSEA) 2013). Biodiesel is commonly used across Canada.

Biodiesel is temperature-sensitive; at low temperatures, biodiesel can form crystals that can plug the fuel filter. This is similar to petroleum-based diesel; however, the temperature at which crystals form in biodiesel is higher than for petroleum-based diesel. Using a low biodiesel blend can alleviate this issue.

Construction equipment that operate on diesel can also use biodiesel blends. This fuel is produced from renewable feedstocks, such as soybean oil and animal fat, via a process called transesterification. Biodiesel is blended with petroleum-based diesel. A 5% blend, referred to as B5, is typically endorsed by North American engine manufacturers (NRCan 2020).

The use of biodiesel blends up to 5% in construction equipment during the construction phase is technically feasible. Based on the planned increases in renewable biodiesel manufacturing capacity and the improvements that renewable diesel has over biodiesel blends, Cedar assumes that biodiesel blends will not be commercially available when decommissioning begins.

4.3.1.4 Renewable Diesel

Renewable diesel, also referred to as hydrogenation-derived renewable diesel, is produced from the same feedstocks as biodiesel through a process called hydrotreating. Hydrotreating uses hydrogen and high temperature and pressures to convert the oils in the feedstock to simple paraffins (Digital Refining 2010). Chemically, renewable diesel is the same as petroleum-derived diesel and has several advantages over biodiesel, including a better emissions profile, lower production cost, and better low-temperature operability (BCSEA 2013). Renewable diesel does not need to be blended with petroleum diesel; it can be used directly with existing engines and infrastructure (RealAgriculture 2021).

Renewable diesel first came on the Canadian market in 2019 and was originally available in Vanderhoof and Quesnel, British Columbia (Federated Co-operatives Limited 2021). However, renewable diesel is not currently manufactured in sufficient quantifies for large scale use in Canada.

Two upstream oil and gas manufacturers have announced plans to build renewable diesel manufacturing facilities. In July 2021, Tidewater Midstream announced plans to build a 3 million barrel per day renewable diesel facility at its Prince George refinery in British Columbia. The new facility is planned to be operational in 2023 (Tank Storage Magazine 2021).

In August 2021, Imperial Oil announced it is planning to build a 20,000 barrels per day renewable diesel facility at the existing Strathcona Refinery in Alberta (Financial Post 2021). This facility would use hydrogen generated from natural gas with carbon capture technology installed and vegetable oils to make renewable diesel. Imperial Oil plans for this new refinery to be operating in 2024.

Based on the recent announcements of increased renewable diesel manufacturing capability, and considering the construction time period of 2023 to 2027, Cedar believes that renewable diesel is technically feasible during the construction period. Cedar also assumes that renewable diesel will continue to be available during the decommissioning phase.

4.3.1.5 Liquefied Natural Gas

Liquefied natural gas is more energy dense than compressed natural gas (CNG) and is the preferred option in applications that need a fuel range comparable to gasoline or diesel. Currently available natural gas vehicles may run solely on natural gas, operate using a bi-fuel system (gasoline and natural gas), or a dual-fuel system that uses diesel for ignition assistance. Although manufacturers offer natural gas vehicles directly, aftermarket conversion kits for traditionally gasoline or diesel vehicles are also available (Federated Co-operatives Limited 2021).

There are dual-fuel LNG/diesel conversion kits for certain heavy-duty mining trucks commercially available currently (IM Mining 2020, Australian Mining 2013) with new conversion kits still in development. However, no conversion kits are currently available for conventional construction equipment. In addition, there is currently no construction equipment available for purchase that operate solely on LNG.

Based on this information, Cedar does not believe that LNG fuel in construction equipment will be technically feasible for the construction phase. Once decommissioning begins, it is reasonable to expect the LNG and diesel dual-fuel systems may be more available in construction equipment. Therefore, LNG is considered technically feasible during the decommissioning phase.

4.3.1.6 Electricity

Rather than using fossil fuel combustion to power vehicles, electric-drive vehicles use batteries to store and provide energy. The length of operation depends on the activities undertaken and the capacity of the installed batteries and is expected to be in the order of hours. The use of electric-drive equipment would result in no direct GHG emissions at the Project site and limited indirect GHGs if a low GHG intensity energy source is used to charge the batteries. The use of batteries requires charging spare batteries and replacing spent batteries as needed.

Electricity generation is well established throughout the world. There are many energy sources and technologies available to generate electricity. Further, the transmission of electricity from a generation station to users can be readily accomplished using above-ground transmission lines.

The use of lithium-ion batteries to store electricity is well established for smaller electronics, such as laptops or cell phones. There are batteries of the size needed for underground mining equipment that are currently being tested. The underground Borden gold mine in Ontario has been operating since October 2019 and presents a test case for using battery-operated mining equipment. The mine life is expected to be 7 to 15 years.

As of June 2021, Volvo has a 24 hp electric excavator (ECR25) and a 43 hp electric wheel loader (L25) commercially available (Volvo 2021a). However, both models are very small in terms of available horsepower. For comparison, the diesel excavators and loaders that were assumed for the calculation of GHG emissions from construction activities have engine powers that range from 140 hp to 385 hp. Although Volvo is developing other electric models (Volvo 2021b), equipment in the size range required for the Project are not currently available and there is no timeline for availability.

Based on this information, Cedar believes that electric-drive construction equipment is not technically feasible for the construction phase of the Project. As the technology is expected to advance, it is reasonable to assume that electric-drive construction equipment would be technically feasible once decommissioning begins.

4.3.1.7 Hydrogen

The hydrogen fuel cell generates electricity through the chemical reaction between hydrogen and oxygen. The chemical reaction does not release GHGs or air contaminants; water is the only result. The hydrogen fuel cell technology itself is relatively new and is used mainly in vehicles or small mobile equipment (e.g., forklifts). Like an electric battery in a vehicle, a hydrogen fuel cells remains in the equipment and is refuelled similar to gasoline or diesel (US Office of Energy Efficiency & Renewable Energy 2016).

Hydrogen fuel cells are already in use in approximately 11,000 cars and in over 20,000 forklifts globally (IEA 2019). British Columbia has three public hydrogen fueling stations with plans for three more to be completed by the end of 2021 (CleanBC Go Electric Program n.d.). Fuel cells are also in use in buses and trains globally (Government of Canada 2019). One type, the Ballard Power System, can provide up to 200 kW (248 hp) and is commercially ready for deployment in buses, trucks, and light rail applications (Government of Canada 2019).

With regards to hydrogen used in construction equipment, there are no commercially available construction equipment. Leading manufacturers have announced prototypes and plans to incorporate hydrogen fuel cells in construction equipment. Of note is the recent work by Hyundai. Hyundai currently produces a fuel cell heavy-duty truck. Hyundai recently announced its Hydrogen Vision 2040 roadmap, which includes a new generation of fuel cell technologies and applying fuel cells to commercial vehicle models by 2028. By 2023, Hyundai is expecting to release fuel cells that are smaller than its current Nexo fuel cells but offering double the power output, higher durability, and less cost (CNET 2021). The most significant change in this new fuel cell technology is that it is modular, where multiple units can be stacked to offer up to 1,000 kW (1,341 hp) of output. Hyundai is also developing a mobile hydrogen refueling station, similar to a diesel fuel truck for diesel-fueled equipment.

Currently, most of the hydrogen used globally is produced from fossil fuels; a small fraction of hydrogen is produced via electrolysis (IEA 2019). Less than 0.7% of current hydrogen production is from renewables or from facilities equipped with carbon capture technologies. The production of hydrogen using current fossil fuel technologies is responsible for approximately 830 million tonnes of carbon dioxide per year.

The source of the energy used to produce hydrogen dictates how decarbonized the hydrogen value chain actually is. Recently, colours are being used to describe the different energy sources used to produce hydrogen. Hydrogen produced via fossil fuels without carbon capture technologies is referred to as “black” (from coal), “grey” (from methane), and “brown” (from lignite), whereas fossil fuel systems with carbon capture produce “blue” hydrogen. Hydrogen that is produced using renewable electricity is referred to as “green” (IEA 2019).

Based on this information, hydrogen fuel cells in construction equipment are not technically feasible currently but may become available as early as 2030. Depending on how hydrogen production technologies advance, particularly whether hydrogen can be made with a lower GHG emissions intensity, hydrogen may not be a technically feasible fuel. The use of hydrogen fuel cells in equipment may be technically feasible during decommissioning; it has been carried forward as an option worth considering.

4.3.2 Operation

4.3.2.1 Regeneration Gas Heater and Auxiliary Boiler

The feed gas contains small amounts of natural gas liquids (NGLs, components such as propane, butane, pentane, hexane, and heptane); these must be removed prior to liquefaction to avoid freezing under cryogenic conditions. This by-product has value; most LNG facilities in operation today remove these components and fractionate them to use as refrigerants or to export to market. However, because the Project has heat requirements, these natural gas liquids were considered as combustion fuel to generate heat for the regeneration gas heater and the auxiliary boiler. If the NGLs are not used in this way, they would be transported off-site for use as is or fractionated on-site to produce individual liquid hydrocarbon streams for export to market. From a technical feasibility perspective, these two alternatives are not preferred for the following reasons:

- Although natural gas liquid fractionation is a widespread technology with little risk to implementation, it would involve additional space and significant energy requirements on the FLNG
- A system to export the NGLs by water or rail would require additional space and energy

If electricity was used for the regeneration gas heater and the auxiliary boiler, approximately 35 MW of additional electricity demand would be required to meet the Project's regeneration energy needs, in addition to the energy needed to process and export the NGLs.

One of the identified acquired energy technologies is the combined cycle gas turbine system. In addition to generating electricity, waste heat can be recovered from the turbine exhaust stream. Preliminary estimates indicated that there would be sufficient waste heat to meet the heating needs of the Project.

The use of the NGLs to generate heat for the regeneration gas heater and auxiliary boiler is technically feasible. The use of electricity and waste heat from a combined cycle gas turbine system to meet the heat demand is also technically feasible.

4.3.2.2 Acid Gas Containing CO_2

Prior to the liquefaction of natural gas, acid generating contaminants such as hydrogen sulphide and carbon dioxide must be removed to prevent damage to downstream equipment. This is accomplished through an acid gas removal unit, which produces an acid gas stream that is mainly composed of carbon dioxide and a small amount of hydrogen sulphide and hydrocarbons. The destruction of the hydrogen sulphide in the acid gas stream is required; without this step, hydrogen sulphide would be emitted to the atmosphere at levels that could be hazardous to personnel in the area. Cedar considered two destruction technologies: a thermal oxidizer and a flare.

A thermal oxidizer can incinerate the acid gas stream when natural gas is used to support the combustion. This system can control the combustion temperature for complete destruction of hydrocarbons and sulphur compounds. In addition, there is no visible flame that can be seen from outside the unit. By comparison, a flare system is not as efficient at destruction and has a visible flame that is always present. In both cases, the CO_2 present in the acid gas is not destroyed and is released to the atmosphere.

While the CO_2 can be stripped from the acid gas to produce a high purity CO_2 stream, there are no storage opportunities on the west coast of British Columbia. The nearest suitable location for storage would be north-eastern British Columbia (approximately 630 km), which has depleted gas pools and deep saline formations suitable for CO_2 storage (Government of British Columbia n.d.). If CO_2 storage were to be included in the Project, transportation to the Fort Nelson area for storage could, theoretically, be achieved via trucking or a dedicated pipeline system.

The Alberta Carbon Trunkline (ACTL) was commissioned in 2020 to transport captured and liquefied CO_2 from two industrial facilities (Nutrien Redwater and Sturgeon Refinery near Edmonton) to enhanced oil recovery operations in central Alberta (Alberta Carbon Trunk Line 2021). The injected CO_2 is permanently sequestered in oil reservoirs. The ACTL is a 240 km pipeline that, at full capacity, can transport approximately 14 million tonnes of CO_2 emissions per year. Construction of the ACTL had started in 2011 and was expected to be complete in 2013, but the project's completion had been delayed to 2020, partially due to delays with construction of the Sturgeon refinery (ConstructConnect Canada, Inc. 2016). From start to completion, approximately nine years was needed to construct and commission the ACTL. This does not include the amount of time needed for project design and environmental impact assessments, which can be five years or more.

A demonstration CO_2 capture, transport, and injection system existed in Saskatchewan: the Weyburn-Midale Carbon Dioxide Project, which includes a 320 km pipeline (from Beulah, North Dakota) to Weyburn, Saskatchewan. This project operated from 2000 to 2012 and captured approximately 8,500 tonnes of CO_2 per day (Petroleum Technology Research Group 2021).

In June 2021, Pembina Pipeline Corporation and TC Energy Corporation announced a plan to jointly develop a world-scale carbon transportation and sequestration system which, when fully constructed, will be capable of transporting more than 20 million tonnes of CO_2 annually. This project is referred to as the Alberta Carbon Grid. By retrofitting older pipeline systems, building new gathering lateral pipelines, and building a sequestration hub, Pembina and TC Energy plan to connect the oil sands to a sequestration location near Fort Saskatchewan. The first phase of the project could be completed as early as 2025, with full scale completions as early as 2027 (TCE 2021).

Based on this information, the technology to capture, transport, and inject CO_2 exists and is in commercial use in Canada. Therefore, carbon capture and storage is technically feasible but would take a substantial amount of time to implement (approximately 15 years).

4.3.2.3 Acquired Energy

The power requirements for the Project are anticipated to be approximately 169 MW under normal operation and 179 MW at peak demand (i.e., when loading LNG onto the LNG carriers). The average electricity consumption is approximately 1,461 GWh per year; this estimate is based on the assumption that in any given year 315 days are considered normal operation and 50 days are spent loading LNG carriers. Cedar has investigated options of self-generation (gas, solar, wind, biomass) or purchasing electrical power from the BC Hydro electrical grid to meet this demand.

Combined Cycle Gas-Fired Turbines

The self-generation option using combined cycle gas-fired turbines would require the construction of a power generation facility that would be located either onshore, on a temporary self-contained floating power barge, or integrated into the FLNG facility. Fuel supply for the power facility would be taken from the incoming natural gas. Approximately 5% to 7% of the natural gas delivered to the Project would be used by the gas-fired turbines for the liquefaction process and to generate electricity to power the remainder of the FLNG facility. This option would generate air contaminant and GHG emissions from the combustion of natural gas. This option also produces waste heat that can be captured and used for regeneration heating purposes (see section 4.3.2.1).

A combined cycle gas-fired turbine to generate electricity is a mature technology that poses very little risk to implementation. It is considered technically feasible to implement currently.

Steam Turbines with Biomass Combustion

The combustion of biomass can be used to produce electricity when boiler steam is run through a steam generating turbine. This system can also be designed to heat in a combined heat and power (CHP) set-up. Typically, the source of the biomass is wood waste from other industrial activities such as pulp mills, which consistently generate high volumes of waste that require use or disposal. Due to the high energy load of the Project, a substantial amount of wood waste would be required annually. There are no substantive wood waste sources near the Project.

A combined heat and power system to generate electricity using biomass is a mature technology. However, sourcing enough biomass to operate the system at this location over the lifetime of the Project would be difficult. Therefore, biomass combustion is considered to not be technically feasible either currently or over the Project lifetime.

Solar Energy

A photovoltaic system using solar panels generates electricity from solar irradiance. The amount of solar irradiance at a given location varies daily depending on weather (e.g., cloud cover), season, and sun activity, but can be approximated based on historical weather conditions. The area where the Project is to be located could produce an average of 1,004 kWh/kW/year (Rylan Urban 2018). Therefore, to produce 1,480,440 MWh annually to supply the Project, a solar farm with an installed capacity of approximately 1,475 MW would be required.

Large scale solar farms are typically mounted on structures on the ground. The efficiency of the system's technology to convert sunlight to energy dictates the physical footprint required to generate a specified amount of power. Crystalline solar panels are approximately 18% efficient, with higher efficiencies being gained each year. Depending on the technology selected, a solar farm designed to generate 1,475 MW would require approximately 11 km^2, assuming a flat area.

The Project's footprint is approximately 11 ha or 0.11 km^2 (see Application Section 1.9). Therefore, the area for the solar farm would be 100 times the Project's footprint.

The availability of solar energy is intermittent. Because electricity is in constant demand, a back-up system to provide electricity when solar energy is not available would be required. This back-up system would likely be generated by natural gas combustion, given its availability to the Project. Due to the large amount of land area required to install sufficient solar energy equipment, the use of this technology to meet the Project's needs is not technically feasible.

Wind Energy

Wind power is generated from the rotation of turbines by the wind to turn generators. Wind turbines for commercial electricity generation are typically 50 m to 105 m tall and can be rated between 1 MW and 3 MW per turbine (Bhandari et al. 2020). Turbine rotor diameters for a 2 MW turbine can be up to 132 m (GE Renewable Energy 2021).

As of December 2019, there is 713 MW of installed wind energy capacity in British Columbia (canwea 2021). This includes 292 wind turbines.

Like solar power, wind power is intermittent and dependent on the wind speed over time at a given location. A back-up electricity generator, such as a natural gas turbine, would be required.

The area needed for a wind turbine farm is substantial. While the individual footprint of a wind turbine is small (approximately 0.25 acres [NREL n.d.]), the distance between wind turbines is required to be between 5 and 10 turbine diameters (660 m to 1,320 m for turbines with 132 m diameter rotors). Using basic assumptions on currently available wind power and turbine technology, approximately 100 wind turbines at 2 MW each would be required to meet the Project's power needs. This represents nearly a third of the turbines that are currently installed in British Columbia.

Due to the large amount of land area required to install sufficient wind energy equipment, the use of this technology by the Project is not technically feasible.

BC Hydro Electrical Grid

There is currently no electrical grid connection in the Project Area. A new transmission line from the Minette substation in Kitimat would need to be constructed (approximately 8 km). BC Hydro, the provincial generator of electricity, has indicated that it can supply enough electricity to meet the Project's demand. In 2019, British Columbia's electrical grid was mainly supplied by hydroelectric, in addition to wind, solar, natural gas, and other refined petroleum products.

If electricity transmission from BC Hydro is interrupted, three back-up diesel generators are included in the technology bundle with the electrical grid connection. These generators are necessary to operate critical services during an electricity interruption. The generators are not sized to supply all electricity for the Project and are only considered as part of the grid connection technology.

A connection to the BC Hydro electrical grid, which generates electricity from existing facilities, is a mature technology that poses very little risk to implementation. It is considered technically feasible to implement currently. Similarly, the use of back-up diesel generators is a mature technology that poses very little risk to implementation. It is considered technically feasible to implement currently.

4.3.2.4 Disposal of Natural Gas During Maintenance, Upset, and Emergency

During upset and emergency conditions, the Project requires a reliable and safe means to quickly dispose of natural gas to protect personnel and equipment. The technology that best suits these requirements is a flare with a continuous pilot flame. A flare header system can be sized to handle high-pressure and low-pressure sources that are typically routed to the atmosphere through one flare stack. Flare systems are used at upstream and midstream oil and gas facilities throughout the world for destruction of hydrocarbon vapours.

In upset and emergency conditions, the alternate technologies of the thermal oxidizer or a vapour recovery unit (VRU) are not suitable for the following reasons:

- A thermal oxidizer and VRU are not able to handle sudden increases in gas volume
- A VRU is not able to handle high pressure gases

For maintenance events, where personnel can prepare for gas to be removed from piping and equipment, the use of a thermal oxidizer to convert the methane in the natural gas to carbon dioxide is possible. A VRU is designed to handle low pressure gases and entrained liquids and is not suitable for maintenance purposes. VRUs are planned to be installed to help reduce venting of natural gas, such as from the boil-off gas (BOG) from the loading of LNG carriers.

A flare system sized to handle upset and emergency conditions is technically feasible. The use of a thermal oxidizer to handle maintenance depressurization events is technically feasible. A VRU is not considered to be technically feasible for the reliable and safe control of natural gas during maintenance, upset, and emergency conditions.

4.3.2.5 LNG Carriers in Transit and at Terminal

The conventional approach is for LNG carriers to use boil-off gas or low sulphur marine gas to provide energy to the propulsion engines (while transiting) and the auxiliary engines while loading. The fuel used while the LNG carrier is at the Project terminal must comply with the fuel sulphur limit imposed by the North American Emission Control Area (US EPA 2010). Engines that combust petroleum-based fuels are commonplace around the world for marine propulsion and auxiliary engines; there is no technological risk to implementation.

Another option that is available in some ports is shore-based power, also referred to as “cold-ironing”, “alternate marine power”, or “High Voltage Shore Connection systems” (Marine Insight 2021). When available and a vessel is equipped to make use of shore-based power, the vessel’s auxiliary engines are turned off and the vessel relies on electricity generated either at the terminal or via an electrical grid connection.

In addition to a port having the necessary infrastructure to provide shore-based power, a vessel must be equipped to accept shore-based power. Vessels can be built to include the necessary equipment (a main switch and a transformer) (Sustainable World Ports n.d.). Older vessels can be retrofitted. However, there is not much demand to perform such retrofits for two reasons:

- Ports where LNG carriers visit are generally not equipped for shore-based power
- An electrical shore connection would hinder an LNG carrier’s ability to quickly disconnect in an emergency

Cedar does not have control over the specific LNG carriers that would be calling at the Project. At the start of the Project lifetime, Cedar expects that conventional dual fuel LNG carriers would be arriving at the Project. It is technically feasible that, in the future, LNG carriers will be designed to accept shore-based power; however, based on recently manufactured LNG carrier designs, it is more feasible that other liquid or gaseous fuel engine technologies would be used. For this assessment, Cedar assumes that the use of boil-off gas and low sulphur marine gas will continue to be used throughout the Project lifetime.

4.3.2.6 Tugboat at Terminal

Tugboat propulsion systems typically use marine diesel as the energy source in very large engines (e.g., 3,600 brake horsepower in a Cummins engine [Cummins 2019]). Marine diesel engines are commonplace and is expected to be available throughout the Project lifetime; therefore, the use of marine diesel is technically feasible.

As described in Section 4.3.1.2, a recent announcement by HaiSea Marine indicates that dual fuel LNG/diesel and fully electric tugboats are planned to be in service in 2023 (Seaspan 2021). The electric tugboats would be connected to shore-based power at its home berth and powered by a connection to the BC Hydro electric grid. The use of dual fuel LNG/diesel and fully electric tugboats is technically feasible.

4.3.3 Practices

4.3.3.1 Carbon Sinks

The land associated with the Project that is vegetated needs to be cleared during construction. Cedar's contractors will identify and remove merchantable timber for sale or donation prior to biomass removal. The remaining above-ground biomass may be burned or chipped and spread; these activities would release CO_2 emissions. The below-ground biomass would decay over time, potentially releasing methane.

Once the construction is complete, the areas associated with the temporary work areas are allowed to revegetate. The new vegetation acts as a carbon sink, sequestering CO_2.

4.3.3.2 Anti-idling Policy

Idling vehicles reduces their fuel economy and thus increases greenhouse gas emissions. Implementation of an anti-idling policy is feasible and would be part of the construction tender and plan. An awareness campaign will be employed to encourage reduction of unnecessary idling and construction site inspections would include review for excessive idling.

4.3.3.3 Optimal Sizing

By sizing construction equipment appropriately, engines required to complete the various construction tasks can be operated at their optimum capacities, thereby optimizing fuel efficiencies. The construction tender and construction plan will include requirements for consideration of equipment sizing to appropriately meet the needs of the project.

4.3.3.4 Regular Maintenance

Regulator equipment maintenance will be a requirement of the construction tender and plan and help manage equipment engine performance including fuel efficiencies.

4.3.3.5 Fuel or Electricity Consumption Monitoring

Monitoring of energy consumption during all phases of the project is a feasible activity to provide data to support the evaluation of overall project GHG performance and identify any divergences from predicted emissions and identify potential equipment performance issues. The level of disaggregation feasible will be defined for various activities based on ease of measurement and magnitude of expected emissions associated with the fuel and energy consumption.

4.3.3.6 Energy Efficiency Measures

Throughout the project design, it is feasible and desired to identify opportunities for energy efficient options for equipment. Cost will not be the only consideration in equipment selection; energy efficiency will also be a key parameter.

4.3.3.7 Efficient Contractor Fleets

As engine technologies evolve to increase fuel efficiency and regulations are made to decrease GHG and air contaminant emissions, newer heavy-duty mobile equipment are preferred over older models. Cedar can specify contractors use newer equipment.

4.3.3.8 Traffic Management Plan

Cedar can reduce GHG emissions from personal vehicle traffic to the Project site by designating "park and ride" locations with bussing from the location to the Project site. Such a plan could also be implemented at the decommissioning phase.

4.3.4 Technical Feasibility Summary

The BAT/BEP that were considered technically feasible in the above section and that will be carried forward are shown in Table 7.

Table 7 Results of Technical Feasibility Assessment

Phase/Year	Source	Technically Feasible Technologies	Practices
Construction	Carbon sinks	• Not applicable	• Biomass burning • Decomposition • Site remediation • Merchantable timber recovery
	On-land equipment	• Diesel • Biodiesel blend • Renewable diesel	• Anti-idling policy • Optimal sizing • Regular maintenance • Preference for contractors with newer (more efficient) fleets • Traffic management plan (e.g., bussing)
	Marine equipment	• Marine diesel • Dual fuel diesel/LNG • Electric (battery)	• Optimal sizing • Regular maintenance • Energy efficiency measures

Table 7 Results of Technical Feasibility Assessment

Phase/Year	Source	Technically Feasible Technologies	Practices
Operations	Acquired energy	• Connection to BC electricity grid with back-up diesel generators on-site • Combined cycle gas-turbine on-site	• Regular maintenance of equipment (on-site only) • Measurement of electricity consumption
	Regeneration gas heater	• Natural gas liquid combustion • Electricity • Waste heat from combined cycle gas turbine system	• Energy efficiency measures • Fuel monitoring • Regular maintenance • Optimal sizing
	Auxiliary boiler	• Natural gas liquid combustion • Electricity • Waste heat from combined cycle gas turbine system	• Energy efficiency measures • Fuel monitoring • Regular maintenance • Optimal sizing
	Acid gas containing CO_2	• Thermal oxidizer with natural gas combustion to support • Carbon capture and storage prior to oxidizer • Carbon capture and usage prior to oxidizer	• Optimal sizing • Fuel monitoring • Regular maintenance • Energy efficiency measures
	Disposal of natural gas during maintenance, upset, and emergencies	• Flare • Thermal oxidizer	• None
	LNG carriers in transit	• Dual fuel boil-off gas and low sulphur marine gas	• None
	LNG carriers at terminal	• Dual fuel boil-off gas and low sulphur marine gas	• None
	Tugboat at terminal	• Marine diesel • Dual fuel diesel/LNG • Electric (battery)	• None

Table 7 Results of Technical Feasibility Assessment

Phase/Year	Source	Technically Feasible Technologies	Practices
Decommissioning	Carbon sinks	• Not applicable	• Site remediation
	On-land equipment	• Diesel • Renewable diesel • LNG • Electric • Hydrogen	• Anti-idling policy • Optimal sizing • Regular maintenance • Preference for contractors with newer (more efficient) fleets • Traffic management plan (e.g., bussing)
	Marine equipment	• Marine diesel • Dual fuel diesel/LNG • Electric (battery)	• Optimal sizing • Regular maintenance • Energy efficiency measures

4.4 GHG REDUCTION POTENTIAL

The GHG reduction potential for each selected technology and practice is estimated against a baseline "business as usual" case, which typically represents the current use of fossil fuels.

4.4.1 On-land Mobile Equipment During Construction and Decommissioning

Both diesel and biodiesel result in GHG emissions when combusted. The "business as usual" case during the construction phase is the use of diesel derived from crude oil and the alternate fuel is 5% biodiesel. In Canada, CO_2 emissions that are released from the combustion of biogenic sources are not counted towards reporting thresholds and are reported separately from CO_2 generated from fossil fuel combustion. The GHG emissions from on-land equipment combusting diesel during construction were estimated to be approximately 6,015 tonnes CO_2e over the construction period using brake-specific fuel consumption from the US EPA MOVES2014b program (US EPA 2018) and emission rates from the Western Climate Initiative (WCI 2011). By replacing 5% of the diesel with biodiesel and calculating emissions using the same methodology, the GHG emissions from the biodiesel blend would be 5,720 t CO_2e. Therefore, the potential emissions reductions could be approximately 295 tonnes CO_2e over the construction period.

During decommissioning, the most emission-intensive fuels will be diesel and LNG. If diesel were used 100% of the time, the estimated GHG emissions from decommissioning activities are anticipated to be similar to those in construction (6,015 t CO_2e). If LNG was used 100% of the time for decommissioning activities, the estimated emissions would be approximately 4,293 t CO_2e, when using default higher heating values for diesel and natural gas from US EPA (1995) and emission factors from the ECCC NIR (ECCC 2021b).

Renewable diesel is 100% from biogenic material. The current approach to CO_2 emissions from the combustion of biogenic material is to exclude these emissions from the total (as per NIR guidance [ECCC 2021b]). Because renewable diesel is chemically the same as petroleum diesel, the CH_4 and N_2O emissions calculated for construction emissions would be the same as those for renewable diesel in decommissioning. The estimated decommissioning emissions from the use of reneNwable diesel are, therefore, approximately 375 t CO_2e, which is potential reduction of 94% over the use of diesel.

Emissions from the use of electricity during decommissioning would depend on the electricity generation sources present at that point in time. As Canada has a net-zero target by 2050 and British Columbia has announced a 100% clean delivery standard by 2030 (Government of British Columbia 2021a), it can be assumed that emissions from electricity generation will be at or close to zero tonnes CO_2e annually.

Hydrogen as an energy source does not release GHG emissions during use.

4.4.2 Marine Equipment During Construction

According to Seaspan, the GHG emissions from dual fuel and electric tugboats are expected to release 54% and 24% lower emissions than traditional diesel-powered tugboats (Seaspan 2021). Using the estimated diesel tugboat emissions from Section 8.0 of the Application during construction, the GHG emissions may be reduced by an estimated 888 t CO_2e to 2,000 t CO_2e during the construction period with the use of these propulsion technologies.

4.4.3 Acquired Energy During Operation

The GHG emissions associated with electricity delivered by the BC Hydro electrical grid were estimated using the emission factors available in the draft Technical Guide (ECCC 2021a). The emission factors decrease each year to represent further greening of the BC Hydro electrical grid. The average GHG emissions from acquired energy in each year of operation were estimated to be 24,749 t CO_2e per year. If natural gas were used in a combined cycle gas turbine system to generate the Project's electricity, an estimated 562,257 tonnes CO_2e would be generated each year. Therefore, the use of electricity from BC Hydro versus electricity generated onsite with natural gas results in an average GHG reduction potential of 537,508 t CO_2e per year.

4.4.4 Regeneration Gas Heater and Auxiliary Boiler

The GHG emissions from the use of the NGL by-product as a fuel for on-site combustion were estimated to be approximately 16,071 t CO_2e per year. If the NGL by-product was instead shipped to Asia for use as a feedstock in a refinery, the following additional GHG emissions would result:

- Indirect GHG emissions (from electricity use) from the loading of the NGL by-product into a tanker vessel

- GHG emissions from tanker transport to refinery (marine gas or potentially NGL combustion)
- GHG emissions from the fractionation of the NGL or other physical or chemical transformations (likely fossil fuel combustion)

The majority of these GHG emissions would be generated outside of Canada. The end result of transporting the NGL by-product for use elsewhere is combustion of the NGLs. Further, if the NGL by-product was not combusted, Cedar would require approximately 35 MW of electricity sourced from BC Hydro in addition to the electricity needed to store LNG and load the tanker vessel, which would result in up to an additional 6,163 t CO_2e per year associated with additional acquired energy. Therefore, the combustion of the NGL by-product at the facility for heat results in the least amount of GHGs between the two options presented.

4.4.5 Acid Gas Containing CO_2

The emissions of CO_2 from the thermal oxidizer are approximately 191,985 tonnes per year; of this amount, 60% is from CO_2 already present in the feed natural gas. If a flare system were used, the CO_2 emissions would be slightly less, given that the flare would not be as efficient as the thermal oxidizer in converting the trace amounts of hydrocarbons to CO_2.

A carbon capture system installed at the Project would require energy to strip the CO_2 out of the acid gas stream; this is a similar technology to that used to strip CO_2 from the natural gas. Once separated, the CO_2 would be transported via pipeline for either use or storage. If used, such as in fertilizer or for carbonation of soft drinks, the CO_2 would not be permanently sequestered and hence there would be no net reduction to GHG emissions. If sequestered, the CO_2 would need to be piped to a suitable location, such as in north-eastern British Columbia. The compressors required to transport and inject the CO_2 require energy to operate; theoretically, such equipment could be connected to the BC Hydro electrical grid and achieve very low indirect GHG emissions. Potentially, there is a net GHG reduction to the permanent sequestration of CO_2.

4.4.6 LNG Carriers in Transit and at Terminal

The use of boil-off gas in place of low sulphur marine gas as a fuel reduces GHG emissions because natural gas releases fewer GHGs than marine gas per unit of energy. Based on the emission factors found in Canada's National Inventory Report (ECCC 2021b), the ratio of GHG emissions from the combustion of marine gas to natural gas is approximately 1.2; that is, about 20% more GHGs by mass are released from the use of marine gas than from the combustion of natural gas. This estimated ratio accounts for the difference in higher heating value between the two fuels. Therefore, the use of boil-off gas to replace marine gas does result in a reduction of GHG emissions.

4.4.7 Tugboat at Terminal

As noted in Section 4.4.2, the use of the dual fuel and electric tugboats during operation are expected to release 54% and 24% lower emissions than traditional diesel-powered tugboats (Seaspan 2021). During operation, if diesel-powered tugboats were used, the emissions would be approximately 2.12 t CO_2e per year while tugboats are standing-by during LNG carrier maneuvering and loading. The use of the dual fuel and electric tugboats would result in GHG emissions of approximately 0.98 t CO_2e to 1.6 t CO_2e per year, respectively.

4.5 ECONOMIC FEASIBILITY

4.5.1 On-land Mobile Equipment During Construction

The specific equipment used for construction and decommissioning will likely be owned and operated by a contractor on behalf of Cedar. A portion of the equipment costs will likely be passed on to Cedar via the contract. The purchase of fuel to run the equipment will also be passed on to Cedar.

At the time of writing, biodiesel is readily available in British Columbia at approximately CA$1.53 per litre. This price includes British Columbia's current carbon tax rate of $45 per tonne of carbon dioxide equivalent (generated from diesel combustion); this works out to 11.71¢ per litre (Government of British Columbia 2021a). This rate is set to increase to $50 per tonne of carbon dioxide equivalent on April 1, 2022. Although the current British Columbia legislation does not indicate whether the carbon tax rates on fossil fuels will continue to increase, the federal minimum national carbon pollution price schedule for 2023 to 2030 shows the carbon tax rate increasing from $65 to $170 per tonne of carbon dioxide equivalent (Government of Canada 2021).

The cost of diesel, renewable diesel, electricity, and LNG once decommissioning begins cannot be determined at this stage, as many factors, such as demand, supply, and regulations affect the prices. Prior to decommissioning, Cedar and the equipment contractor would assess the economics of using each energy type and the corresponding equipment.

4.5.2 Marine Equipment During Construction

The cost of a tugboat depends greatly on its specifications. As a general range, a newly built tugboat falls in the range of US$750,000 to $10 million or more (Damco Marine Management Inc. 2021). Cedar may order new tugboats to own or may contract tugboat services.

4.5.3 Acquired Energy During Operation

The estimated pre-FEED (front end engineering design) cost for the transmission line and a substation at the Project are approximately $30 million. An estimate for a sufficiently sized combined cycle gas turbine system indicates that the cost is approximately 4% lower. Therefore, the connection to the BC Hydro electrical grid is expected to result in a higher cost to Cedar.

4.5.4 Regeneration Gas Heater and Auxiliary Boiler

The Project is planned to be operated as a tolling facility, such that the LNG buyers pay for the natural gas that is then liquefied. The portion of the natural gas stream that is NGL would have to be contracted for from the LNG buyer, as the NGL has value. This is not dissimilar from purchasing natural gas or electricity for heating. The average price of natural gas for export in Canada is CA$4.13 per GJ (or less than CA$0.01 per L) (CER 2021a), whereas the average price of NGL exported from BC is CA$0.15 per L (CER 2021b). Based on this analysis, there is more economic value for the NGLs to be exported rather than used for heating. The use of NGLs as a fuel for heating is economically feasible in the current Project design.

4.5.5 Acid Gas Containing CO_2

Although a project with much higher capacity, the Alberta Carbon Trunk Line (ACTL) is an existing CO_2 capture, transport, and injection system. The estimated cost of the ACTL was $ 1.2 billion (Verdict Media Limited n.d.). Although aspects of the ACTL are not fully similar to a CO_2 capture, transport, and injection system that could be applicable to the Project, the cost of the ACTL is used as a benchmark for this economic assessment. Prorating the CO_2 design capacity of the ACTL (14 million tonnes CO_2 per year) by the Project's CO_2 emissions from acid gas disposal (approximately 200,000 tonnes CO_2 per year) yields a rough estimate of $17 million. A CO_2 pipeline from the Cedar site location would have to be constructed and connected to the ACTL system at significant cost to the Project. Alternatively, a viable sequestration site would have to be found in British Columbia as close as possible to the Cedar location. In either case, building a CO_2 pipeline will add cost and delays to the Cedar project due to the permitting process.

4.5.6 LNG Carriers in Transit and Terminal

Cedar LNG does not have ownership or control of the specific LNG carriers (and hence their power systems) that will call at the Project. However, there is opportunity for Cedar LNG to include in contracts with LNG buyers conditions or clauses that encourage the use of LNG carriers that have high energy efficiency due to their design or retrofits.

4.5.7 Tugboat at Terminal

See Section 4.5.2 for a discussion of the cost of a tugboat.

4.6 ADDITIONAL CONSIDERATIONS

Cedar is committed to producing industry-leading low-carbon, low-cost Canadian LNG for overseas markets. The combined cycle gas turbine system does not align with Cedar's commitment given the Project's proximity to the BC Hydro electrical grid, which uses hydroelectric to generate low-emission electricity. On this basis, the combined cycle gas turbine system is not considered to be the best available technology for electricity generation. This also means that the use of waste heat for the regeneration heating needs is also not considered to be the best available technology.

4.7 SELECTION OF BAT/BEP

Based on the technical and economic feasibility assessments, and in consideration of the GHG reduction potentials that may be achieved, two emission reduction scenarios with the remaining technologies and practices were considered.

4.7.1 Emission Reduction Scenario 1

The emission reduction scenario 1 is described in Table 8. This scenario reflects the current Project design, including use of BC Hydro electricity, combustion of NGLs for heating, and conservative assumptions for construction equipment and marine vessels. The technologies and practices shown would be implemented as soon as practicable within the phase. For example, technologies associated with project design would be installed during construction and implemented once operation starts. Where multiple technologies are shown, Cedar may implement any of the technologies shown.

Table 8 Scenario 1 BAT/BEP

Phase/Year	Source	Technically Feasible Technologies	Practices
Construction	Carbon sinks	• Not Applicable	• Biomass burning • Biomass chipping and spreading • Decomposition • Site remediation • Merchantable timber recovery
	On-land equipment	• Diesel	• Anti-idling policy • Optimal sizing • Regular maintenance • Preference for contractors with newer (more efficient) fleets • Traffic management plan (e.g., bussing)
	Marine equipment	• Marine diesel	• Optimal sizing • Regular maintenance • Energy efficiency measures

Table 8 Scenario 1 BAT/BEP

Phase/Year	Source	Technically Feasible Technologies	Practices
Operations	Acquired energy	• Connection to BC electricity grid with back-up diesel generators on-site	• Regular maintenance of equipment (on-site only) • Measurement of electricity consumption • Energy efficiency measures
	Regeneration heater	• Natural gas liquid combustion	• Energy efficiency measures • Fuel monitoring • Regular maintenance • Optimal sizing
	Auxiliary boiler	• Natural gas liquid combustion	• Energy efficiency measures • Fuel monitoring • Regular maintenance • Optimal sizing
	Acid gas containing CO_2	• Thermal oxidizer with natural gas combustion to support	• Optimal sizing • Fuel monitoring • Regular maintenance • Energy efficiency measures
	Disposal of natural gas during maintenance, upset, and emergencies	• Flare • Thermal oxidizer	• None
	LNG carriers in transit	• Dual fuel boil-off gas and marine gas	• None
	LNG carriers at terminal	• Dual fuel boil-off gas and low sulphur marine gas	• None
	Tugboat at terminal	• Dual fuel diesel/LNG • Electric (battery)	• None
Decommissioning	Carbon sinks	• Not applicable	• Site remediation
	On-land mobile equipment	• Renewable diesel	• Anti-idling policy • Optimal sizing • Regular maintenance • Preference for contractors with newer (more efficient) fleets • Traffic management plan (e.g., bussing)
	Marine equipment	• Dual fuel diesel/LNG • Electric (battery)	• None

4.7.2 Emission Reduction Scenario 2

The emission reduction scenario 2 is described in Table 9. This scenario shows a more optimistic uptake of available and emerging technologies, particularly with respect to marine vessels and on-land equipment. The Project operational equipment remains the same as for emission reduction scenario 1. The technologies and practices shown would be implemented as soon as practicable within the phase. For example, technologies associated with project design would be installed during construction and implemented once operation starts. Where multiple technologies are shown, Cedar may implement any of the technologies shown.

Table 9 Scenario 2 BAT/BEP

Phase/Year	Source	Technically Feasible Technologies	Practices
Construction	Carbon sinks	• Not applicable	• Biomass burning • Biomass chipping and spreading • Decomposition • Site remediation • Merchantable timber recovery
	On-land equipment	• Biodiesel blend	• Anti-idling policy • Optimal sizing • Regular maintenance • Preference for contractors with newer (more efficient) fleets • Traffic management plan (e.g., bussing)
	Marine equipment	• Dual fuel diesel/LNG • Electric (battery)	• Optimal sizing • Regular maintenance • Fuel or electricity consumption monitoring • Energy efficiency measures
Operations	Acquired energy	• Connection to BC electricity grid with back-up diesel generators on-site	• Regular maintenance of equipment (on-site only) • Measurement of electricity consumption
	Regen heater	• Natural gas liquid combustion	• Energy efficiency measures • Fuel monitoring • Regular maintenance • Optimal sizing
	Auxiliary boiler	• Natural gas liquid combustion	• Energy efficiency measures • Fuel monitoring • Regular maintenance • Optimal sizing

Table 9 Scenario 2 BAT/BEP

Phase/Year	Source	Technically Feasible Technologies	Practices
Operations (cont'd)	Acid gas containing CO_2	• Thermal oxidizer with natural gas combustion to support	• Optimal sizing • Fuel monitoring • Regular maintenance • Energy efficiency measures
	Disposal of natural gas during maintenance, upset, and emergencies	• Flare • Thermal oxidizer	• None
	LNG carriers in transit	• Dual fuel boil-off gas and marine gas	• None
	LNG carriers at terminal	• Dual fuel boil-off gas and low sulphur marine gas	• None
	Tugboat at terminal	• Dual fuel diesel/LNG • Electric (battery)	• None
Decommissioning	Carbon sinks	• Not applicable	• Site remediation
	On-land mobile equipment	• Renewable diesel • LNG • Electric	• Anti-idling policy • Optimal sizing • Regular maintenance • Biomass burning • Preference for contractors with newer (more efficient) fleets • Traffic management plan (e.g., bussing)
	Marine equipment	• Dual fuel diesel/LNG • Electric (battery)	• None

4.7.3 Selected Emission Reduction Scenario

The scenario that is considered BAT/BEP for this Project is scenario 1. This scenario is the basis for the emissions presented in the GHG Technical Data Report and Section 8.0 of the Application and provides a conservatively high estimate of GHG emissions.

4.7.3.1 Discussion

Information on the GHG reduction potential, level of technology maturity, and barriers to implementation for the selected emission reduction scenario are presented in Table 10.

4.7.3.2 Eliminated Technologies and Practices

The following technologies were eliminated during the assessment:

- Construction phase:
  - On-land equipment: electric (battery), hydrogen-based electric, and LNG due to technical feasibility
  - Marine equipment: none
- Operation phase:
  - Acquired energy: combined cycle gas-turbine power plant, wind energy, solar energy, steam turbine with biomass combustion power plant (due to technical feasibility and desire to produce low-carbon Canadian LNG)
  - Regeneration gas heater and auxiliary boiler: electrified equipment and waste heat recovery (due to technical feasibility)
  - Acid gas containing CO_2: flare, carbon capture with use or storage (due to technical feasibility (flare) and economic feasibility (carbon capture and storage))
  - Disposal of natural gas for maintenance, upset, emergency: vapour recovery unit (due to technical feasibility)
  - LNG carriers at berth: shore-based electricity (due to technical feasibility)
  - Tugboat at terminal: none
- Decommissioning:
  - On-land equipment: diesel, LNG fueled on-land equipment (due to technical feasibility)
  - Marine equipment: none

No practices were eliminated during the assessment.

Table 10 Selected BAT/BEP Details

Phase/Year	Source	GHG Reduction Potential	Technology Maturity	Barriers
Construction	Carbon sinks	• None	• Mature	• Permits for burning. • Opportunity to sell/donate merchantable timber.
	On-land equipment	• Diesel is the business as usual technology; therefore, no GHG reduction potential from fuel type • BEP will reduce diesel consumption; however, the effect cannot be quantified without detailed information.	• Mature	• Access to contractors with newer fleets. • Suitable "park and ride" locations.
	Marine equipment	• Although marine diesel has been selected to present worst case GHG emissions, lower GHG emissions are expected if dual fuel and electric tugboats are used. Reductions of 24% to 54% of GHG emissions may be possible. • BEP measures will decrease fuel and/or electricity consumption, resulting in fewer GHG emissions.	• Mature (marine diesel) • Newly mature (dual fuel and electric tugboats)	• Appropriate onshore infrastructure to support LNG and electricity supply to tugboats is required.
Operations	Acquired energy	• Connection to BC electricity grid with back-up diesel generators on-site will result in reductions of 537,508 t CO_2e per year over a natural gas generator system, which is a 96% reduction in potential GHG emissions. • Detailed design will seek to optimize electricity use.	• Mature	• Delays due to construction of the transmission line could result in the need for temporary on-site fossil fuel combusting generators.

Table 10 Selected BAT/BEP Details

Phase/Year	Source	GHG Reduction Potential	Technology Maturity	Barriers
Operations (cont'd)	Regeneration gas heater	• Combusting the NGLs instead of purifying, shipping, and selling reduces GHG emissions. Due to a high level of uncertainty in this scenario, a specific GHG reduction potential cannot be determined. • Detailed design will seek to optimize NGL use.	• Mature	• The quantity of NGLs available for combustion depends on the quality of natural gas received. Natural gas may be combusted as make-up fuel.
	Auxiliary boiler	• Combusting the NGLs instead of purifying, shipping, and selling reduces GHG emissions. Due to a high level of uncertainty in this scenario, a specific GHG reduction potential cannot be determined. • Detailed design will seek to optimize NGL use.	• Mature	• The quantity of NGLs available for combustion depends on the quality of natural gas received. Natural gas may be combusted as make-up fuel.
	Acid gas containing CO_2	• The CO_2 is vented to the atmosphere. Recovery of the CO_2 is not economically feasible at this time.	• Mature	• No barriers.
	Disposal of natural gas during maintenance, upset, and emergencies	• Flaring of natural gas is a business as usual technology. However, using flaring only for maintenance, upset, and emergencies will reduce CO_2 emissions (i.e., venting and fugitive natural gas will be captured and reinjected)	• Mature	• Detailed design of the Project is required to confirm the applicability of natural gas venting and fugitives capture and reinjection.
	LNG carriers in transit and at terminal	• The use of natural gas in place of marine gas can reduce GHG emissions by 20%.	• Mature	• Cedar does not control the technologies on LNG carriers; LNG carriers that do not use natural gas may call at the Project.

Table 10 Selected BAT/BEP Details

Phase/Year	Source	GHG Reduction Potential	Technology Maturity	Barriers
Operations (cont'd)	Tugboat at terminal	• Although marine diesel has been selected to present worst case GHG emissions, lower GHG emissions are expected if dual fuel or electric tugboats are used. Reductions of 24% to 54% of GHG emissions may be possible. • BEP measures will decrease fuel and/or electricity consumption, resulting in fewer GHG emissions.	• Newly mature (dual fuel and electric tugboats)	• Appropriate onshore infrastructure to support LNG and electricity supply to tugboats is required.
Decommissioning	Carbon sinks	• There will likely be minimal GHG emissions from land clearing. Once complete, the project area would be revegetated, thereby increasing carbon sink capacity.	• Mature	• No barriers.
	On-land equipment	• Diesel is the business as usual technology and has been used to estimate GHG emissions in the net emission calculation. • The use of renewable diesel may reduce GHG emissions by 94% over the use of diesel. • BEP will reduce diesel consumption; however, the effect cannot be quantified without detailed information.	• Mature	• No barriers.

Table 10 Selected BAT/BEP Details

Phase/Year	Source	GHG Reduction Potential	Technology Maturity	Barriers
Decommissioning (cont'd)	Marine equipment	• Although marine diesel has been selected to present worst case GHG emissions, lower GHG emissions are expected if dual fuel or electric tugboats are used. Reductions of 24% to 54% of GHG emissions may be possible. • BEP measures will decrease fuel and/or electricity consumption, resulting in fewer GHG emissions.	• Mature (marine diesel) • Expected to be mature at decommissioning phase (dual fuel and electric tugboats)	• Appropriate onshore infrastructure to support LNG and electricity supply to tugboats is required.

5.0 NET-ZERO PLAN

5.1 ADDITIONAL MITIGATION MEASURES

Cedar LNG is a Haisla Nation-led partnership with Pembina Pipeline Corporation (Pembina).

The Haisla Nation is one of the partners of the First Nations Climate Initiative (FNCI). The FNCI has partnered with various organizations including the University of British Columbia and Hatch Engineering to undertake studies on net-zero development in British Columbia.

Pembina is committed to a 30% GHG emission intensity reduction target by 2030, relative to baseline 2019 emissions (Pembina 2021). This commitment illustrates that Pembina has a directed focus on GHG emissions management over the long term. Pembina also has an increasing focus on Environmental, Social and Governance (ESG) and climate change issues as part of investment decisions. ESG has become an additional lens through which Pembina's Investment Committee and Board evaluate capital projects and acquisitions (Pembina 2020).

5.1.1 Schedule for Implementation

Implementation of GHG mitigation will primarily occur as part of design and construction of the project. The mitigation measures will be monitored for effectiveness throughout the life of the project and consideration of potential improvements to mitigation will be made on a re-occurring periodic basis.

5.2 NET EMISSIONS

The emissions profile for this Project, reflecting emission reduction scenario 1, is provided on an annual basis in Table 11. For this initial net-zero plan, it is assumed that Cedar will purchase offset credits to achieve net-zero in 2050. As 2050 approaches, Cedar will consider options to meet the net-zero by 2050 target.

Table 11 Emission Profile of the Project

Year	Direct GHG Emissions (t CO_2e/y)	Acquired Energy GHG Emissions (t CO_2e/y)	CO_2 Captured and Stored (t CO_2e/y)	Avoided Domestic GHG Emissions (t CO_2e/y)	Offset Credits (t CO_2e/y)	Net GHG Emissions (t CO_2e/y)
Construction						
2023	9,163	-	-	-	-	9,163
2024	9,163	-	-	-	-	9,163
2025	9,163	-	-	-	-	9,163
2026	9,163	-	-	-	-	9,163
Operation						
2027	215,700	19,872	-	-	-	235,572
2028	215,700	19,726	-	-	-	235,426
2029	215,700	19,580	-	-	-	235,280
2030	215,700	18,996	-	-	-	234,696
2031	215,700	18,411	-	-	-	234,111
2032	215,700	17,827	-	-	-	233,527
2033	215,700	17,827	-	-	-	233,527
2034	215,700	17,681	-	-	-	233,380
2035	215,700	17,534	-	-	-	233,234
2036	215,700	17,242	-	-	-	232,942
2037	215,700	17,534	-	-	-	233,234
2038	215,700	18,265	-	-	-	233,965
2039	215,700	21,187	-	-	-	236,887
2040	215,700	22,064	-	-	-	237,764
2041	215,700	23,672	-	-	-	239,371
2042	215,700	24,987	-	-	-	240,686
2043	215,700	25,133	-	-	-	240,833
2044	215,700	23,233	-	-	-	238,933
2045	215,700	22,356	-	-	-	238,056
2046	215,700	23,964	-	-	-	239,664
2047	215,700	25,863	-	-	-	241,563
2048	215,700	28,201	-	-	-	243,901
2049	215,700	29,516	-	-	-	245,216
2050	215,700	29,370	-	-	-	245,070
2050–2067	215,700	29,370	-	-	245,070	0

NOTE:
Although emissions are presented for the years of 2050 – 2067, it is assumed that net emissions are assumed to be 0 starting in 2050 (see Section 8.9 of the ESA).

5.3 COMPARISON WITH SIMILAR HIGH-PERFORMING ENERGY-EFFICIENT PROJECTS

The Gorgon LNG and Wheatstone LNG projects have been identified as similar high-performing energy-efficient projects.

5.3.1 Gorgon LNG

The Gorgon LNG project is operated by a joint venture led by Chevron Australia Pty Ltd. It is located on Barrow Island, off the coast of western Australia. The facility began operation in 2015 and currently operates with three trains, producing 3 million tonnes per annum of liquified natural gas, as well as NGLs and domestic gas (i.e., natural gas). LNG and NGLs are exported to international markets using tankers, while domestic gas is piped back to the western Australia mainland (Chevron 2020). The Gorgon project uses natural gas combustion to generate electricity for its operations (Delphi Group 2013).

The Gorgon LNG project is designed to capture CO_2 from incoming natural gas. Although the capture of CO_2 has been implemented in 2015, the injection of CO_2 began in the 2019 and is now injecting 3.4 to 4 million tonnes CO_2e per year (Chevron 2020).

The Gorgon LNG project is considered high-performing because it uses the following technologies:

- **Gas Turbine Performance Improvement**: Performance improvement packages improve the engine efficiency by reducing losses across seals, improved aero performance, and increasing the firing temperature.
- **Advanced Process Control Systems**: Reduce energy use by using computer algorithms to make incremental changes allowing facilities to operate closer to their design limits and increase performance.
- **Regeneration Flash Gas Vapours**: No routine regeneration flash gas vapour emissions during normal operations as the vapour is captured and re-routed to process inlet.
- **Carbon Capture and Sequestration**: 3.4 to 4 million tonnes of carbon dioxide are planned to be removed and sequestered each year going forward.

The 2008 greenhouse gas abatement program report for Gorgon indicated that Gorgon's annual operating emissions were anticipated to be 5,372,630 t CO_2e per year at full operation (Delphi 2013). Of this value, 1% is associated with flaring and fugitive emissions, 16% is associated with acid gas venting (prior to CO_2 capture), and 83% is associated with compressor operation and power generation.

Delphi estimated that the Gorgon project could reach a GHG intensity of 0.27 t CO_2e/t LNG. The average GHG emission intensity of the Gorgon LNG project for the 2019-2020 fiscal year was 0.4 t CO_2e/tonne saleable LNG. This represents the emissions intensity at the start of CO_2 injection. The Gorgon Project GHG emission intensity can be compared to the Project emission intensity of 0.08 t CO_2e/tonne LNG produced. The Project's use of electricity generated by hydroelectric generation gives it a substantive advantage in its emission intensity, despite not using carbon capture and sequestration.

5.3.2 Wheatstone LNG

The Wheatstone LNG project is owned and operated by Chevron Australia Pty Ltd. It is located in the Ashburton North Strategic Industrial area of western Australia. It began operation in 2017 with two LNG trains, producing 8.9 million tonnes per annum of LNG (Chevron 2015). The project generates it own electricity from natural gas combustion.

This facility was designed with the following mitigation measures (EIA):

- No routine flaring
- Practices and technologies to reduce venting and fugitive emissions, including vapor recovery and the use of a thermal oxidizer to convert residual hydrocarbons, including methane, to CO_2
- Waste heat recovery for heating needs

Although CO_2 capture and sequestration was considered for the project, it was not found to be economically feasible due to the low concentration of CO_2 in the natural gas and the lack of a commercially viable geological reservoir.

In the Wheatstone Project draft environmental impact statement, the estimated annual emissions per year from the LNG processing are 9.2 million tonnes CO_2e (Chevron 2011). Of this total, approximately 61% of emissions are from stationary combustion of natural gas for equipment power or electricity generation. Flaring and fugitives account for approximately 1% of the estimated emissions. The venting of reservoir CO_2 accounts for approximately 26% of the estimated emissions.

This yields an emissions intensity of 1.0 t CO_2e/tonne saleable LNG. This emission intensity can be compared to the Project emission intensity of 0.08 t CO_2e/tonne LNG produced. The Project's use of electricity generated by hydroelectric generation gives it a substantive advantage.

5.4 EMISSIONS INTENSITY TARGETS

Emissions intensity targets for the Project have been set in consideration of the available BAT/BEP described in Section 4.7.1 and the expected production rate of 3 million tonnes per year of saleable LNG.

Table 12 Project GHG Emissions Intensity Targets

Year	GHG Emissions Intensity Target (t CO_2e/t LNG)[1]
2027	0.08
2035	0.08
2045	0.06
2050 to Decommissioning	0
NOTE: [1] GHG emissions calculated as net emissions, including CO_2 from biogenic sources.	

5.5 GHG LEGISLATION AND POLICIES

Table 13 presents a summary of the GHG legislation and polices currently known that are relevant to the Project.

Table 13 Summary of Key Legislation and Policies for Greenhouse Gases

Regulation or Policy	Description
Federal	
Pan Canadian Framework on Clean Growth and Climate Change (ECCC 2016)	Reduce GHG emissions 30% below 2005 levels by 2030.
Greenhouse Gas Reporting Program	Section 46 of the Canadian *Environmental Protection Act* requires GHG emissions to be reported via the GHG Reporting Program if facility emissions are greater than 10,000 tonnes CO_2e per year.
Greenhouse Gas Pollution Pricing Act	Implements the federal carbon pricing system. Industrial facilities must comply with the Output-Based Pricing System Regulations, administered by ECCC.
Regulations Respecting Reduction in the Release of Methane and Certain Volatile Organic Compounds (Upstream Oil and Gas Sector)	Reduce methane emissions from the oil and gas sector by 40% to 45% below 2012 levels by 2025. These regulations form part of Canada's commitments under the Pan Canadian Framework on Clean Growth and Climate Change.
Strategic Assessment of Climate Change (ECCC 2021a)	Provides a framework to establish whether a designated project will hinder or contribute to Canada's ability to meet its international commitments to reduce GHG emissions by 30% below 2005 levels by 2030, and to help to achieve a low carbon economy by 2050. The SACC requires: • Estimation of GHG emissions for the Project • Estimation of GHGs from upstream activities • Review of best available technologies • Assessment of climate change resilience • Plan to achieve net-zero emissions by 2050
Canadian Net Zero Emissions Accountability Act	Establishes five-year national emissions-reduction targets for 2030, 2035, 2040, and 2045. The plans developed to meet each target will explain how they contribute to Canada achieving net zero emissions by 2050.
Provincial	
Greenhouse Gas Industrial Reporting and Control Act	Facilities which emit greater than 10,000 tonnes of CO_2e per year are required to report their emissions.
	Establishes a GHG intensity limit of 0.16 tonnes of CO_2e per tonne of LNG produced
Climate Change Accountability Act	Legislated targets for reducing greenhouse gas emissions 40% below 2007 levels by 2030, 60% by 2040, and 80% by 2050. British Columbia has also introduced an interim target of 16% by 2025 and has set an industry sector target for oil and gas of 33%-38% of 2007 levels by 2030.

Table 13 Summary of Key Legislation and Policies for Greenhouse Gases

Regulation or Policy	Description
Flaring and Venting Reduction Guideline	The Flaring and Venting Reduction Guideline (OGC 2021) provides regulatory requirements and guidance for flaring, incinerating, and venting in British Columbia. It applies to the flaring, incineration and venting of natural gas at well sites, facilities and pipelines regulated under the *Oil and Gas Activities Act*.
First Nations Climate Initiative (FNCI 2021)	Sets out policy goals in support of climate change mitigation, the alleviation of poverty, and the transition to a low carbon economy.
Carbon Tax Act	British Columbia established a price on GHGs beginning at $10/tonne in 2008, with planned increases to $50/tonne by 2022.

5.6 ADDITIONAL INFORMATION

5.6.1 Government Assistance

The following suggested British Columbia and federal government actions are recommended to assist organizations moving toward net-zero.

- Development of a robust offset credit system
- Continuance of the push to net-zero GHG emissions by 2050
- Continuance of the British Columbia LNG environmental incentive program

5.6.2 CO_2 Capture Prior to Pipeline

Although CO_2 capture, transport, and storage at the Project was eliminated as BAT due to economic feasibility, a separate project to accomplish this goal at the natural gas processing plants in northeastern BC may prove to be more feasible. Such a project has the benefits of:

- A large number of CO_2 sources in close proximity to storage wells
- Ability to reduce CO_2 emissions at downstream sources for whom CO_2 capture and storage is not economical or technically feasible

5.7 REVISITING THE NET-ZERO PLAN

This net-zero plan is an evergreen document. Cedar will monitor available and emerging technologies and best practices, and assess the technical feasibility, GHG reduction potential, and economic feasibility of these technologies and best practices and update the net-zero plan accordingly.

6.0 CLIMATE RESILIENCE ASSESSMENT

6.1 INTRODUCTION

A Climate Change Resilience Assessment (CCRA) assesses risks to the project due to climate change and highlights adaptation options to help mitigate those risks. This CCRA identifies the climate risks to the Project at a broad systems-level based on a future climate scenario and provides a discussion of the potential climate impacts on the Project over its construction and operational life. This assessment is intended to inform the design and project management team of projected changes in climate and associated risks to consider at the project's detailed design stage, and to highlight climate change impacts on the project operations through the life of the Project.

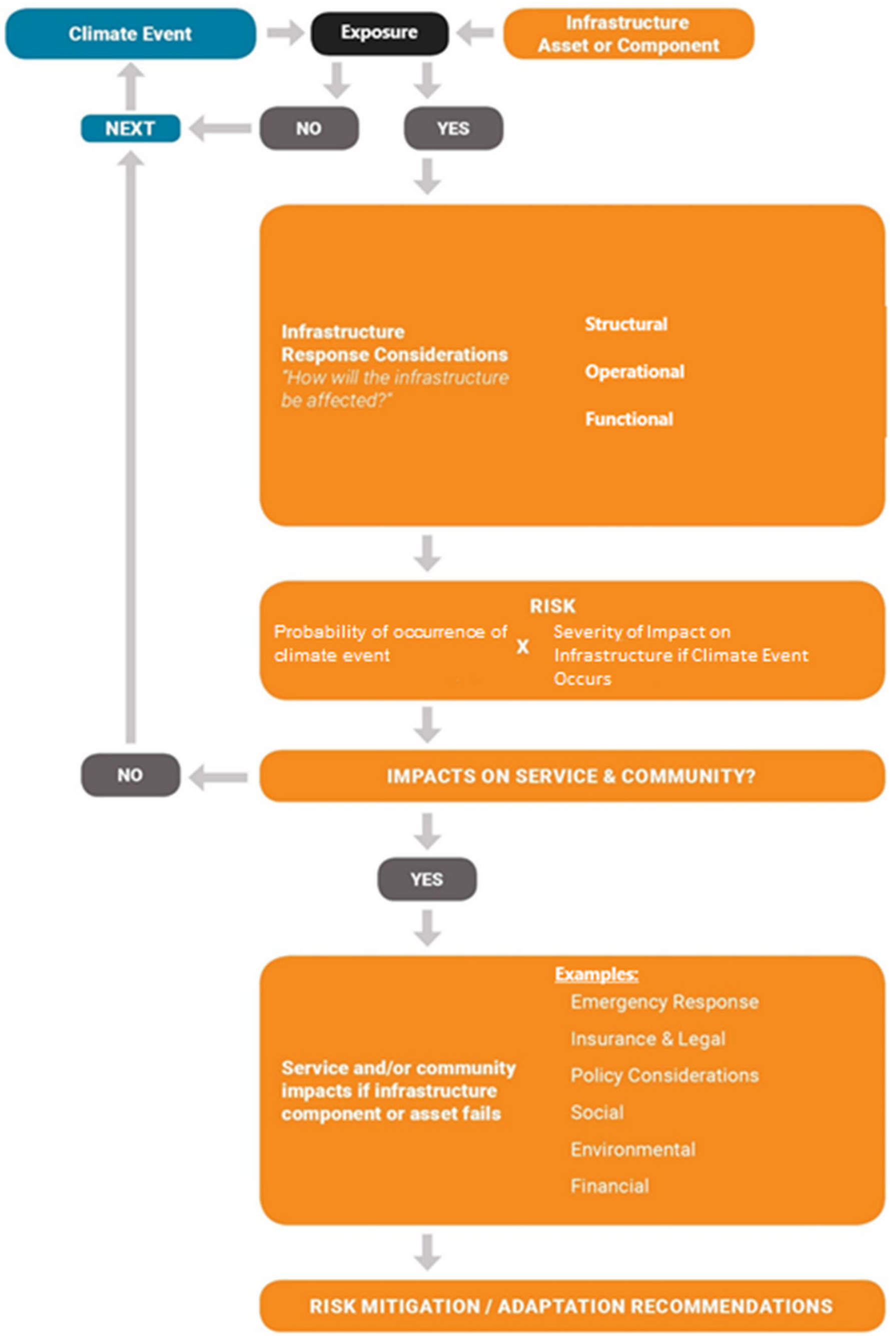
6.2 METHODS

6.2.1 Overview of Climate Change Resilience Assessment Process

This climate resilience assessment evaluates the future climate impacts on the Project's proposed components and associated infrastructure and identifies the potential risks associated with future changes in climate and extreme weather events. It is a high-level assessment of risks to the infrastructure due to extreme weather and climate uncertainty based on current climate and future climate projections in the project site. Extreme weather events may include, but are not limited to, extreme temperatures, freeze-thaw cycles, short-duration high intensity rainfall events, heavy freezing rain events, heavy snowfall events, high wind events, and occurrences of hurricanes/ tropical cyclones.

The climate resilience assessment identifies infrastructure assets, components, and activities and their response to selected climate parameters, under current and future climate conditions. These interactions are used to assign risk ratings to each infrastructure / climate interaction. A flowchart illustrating the steps followed for this CCRA is shown in Figure 4.

Figure 4 Illustration of the Risk Assessment Process



6.2.2 Contributors to Climate Resilience Assessment

Interviews were held with Project staff to collect information on the climate hazards that have occurred with similar projects and also in the region near Kitimat. This information is beneficial for the validation of impacts on vulnerable assets and determining the climate parameters for inclusion in this assessment.

6.2.3 Principles of Climate Change Resilience Assessment

6.2.3.1 Proportionate Assessment

The analysis and recommendations in this Resilience Assessment are based on information available within the timeline and scope of this project, and on the Stantec's experience with climate risks assessments. This assessment represents a level of effort and detail consistent with the criticality of the Project's service and the level of detail of information available.

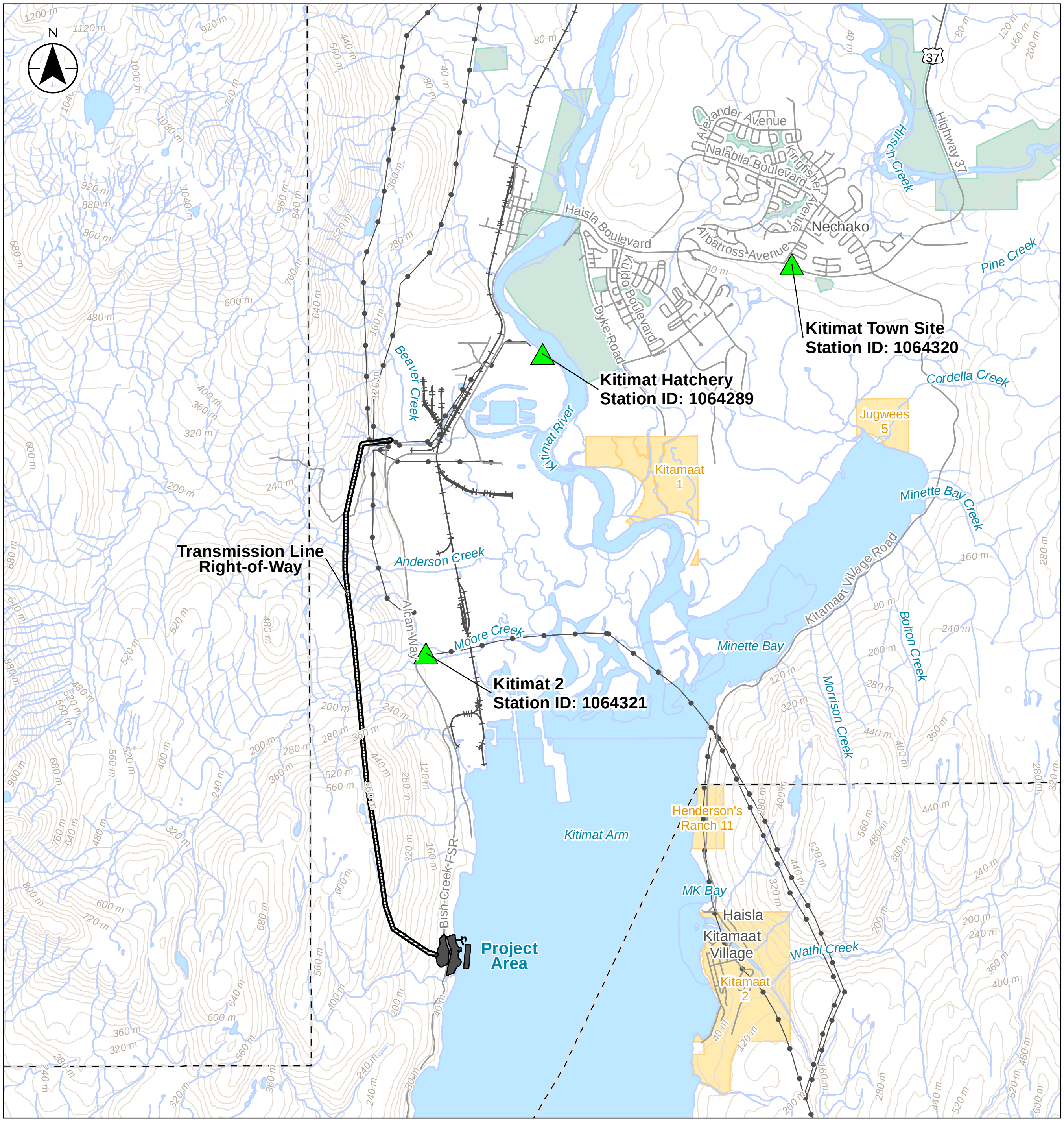
6.2.3.2 Systemic Analysis of Risk

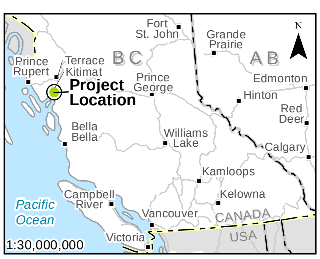
By using a climate change risk assessment methodology that conforms to ISO 31000:2018 Standard Risk Management—Principles and Guidelines, Stantec considers that this high-level risk identification and assessment meets the requirements set by the Strategic Assessment of Climate Change (ECCC 2020) and Infrastructure Canada's Climate Lens – General Guidance v1.2.

6.2.3.3 Climate Data Sources

Historical and future climate data were collected to estimate the likelihood of climate and extreme weather events. There are four ECCC weather stations for the region of Kitimat. A summary of the weather stations with the most complete historical datasets is shown in Table 14, Figure 5 and Figure 6.

In consideration of data availability and the location of the project asset, the Kitimat Townsite and Terrace A weather stations are chosen to represent the climate baseline of the region of Kitimat, temperature, precipitation and snowfall variables will be taken from the Kitimat Townsite weather station, while hourly and daily wind data will be taken from the Terrace A weather station.





Highway
Road
Railway
Transmission Line
Topographic Contour (40 m)
Waterbody
Reserve Land
Local Greenspace
District of Kitimat Municipal Boundary
Minette Substation
Project Area
Transmission Line Right-of-Way
Marine Terminal
Transmission Line Permitting Corridor
Historical Weather Station

0 1 2 3 km

1:75,000 (at original document size of 8.5x11)

Notes
1. Coordinate System: NAD 1983 UTM Zone 9N
2. Data Sources: DataBC, Government of British Columbia; Natural Resources Canada; Canadian Hydrographic Service

Stantec CEDAR LNG

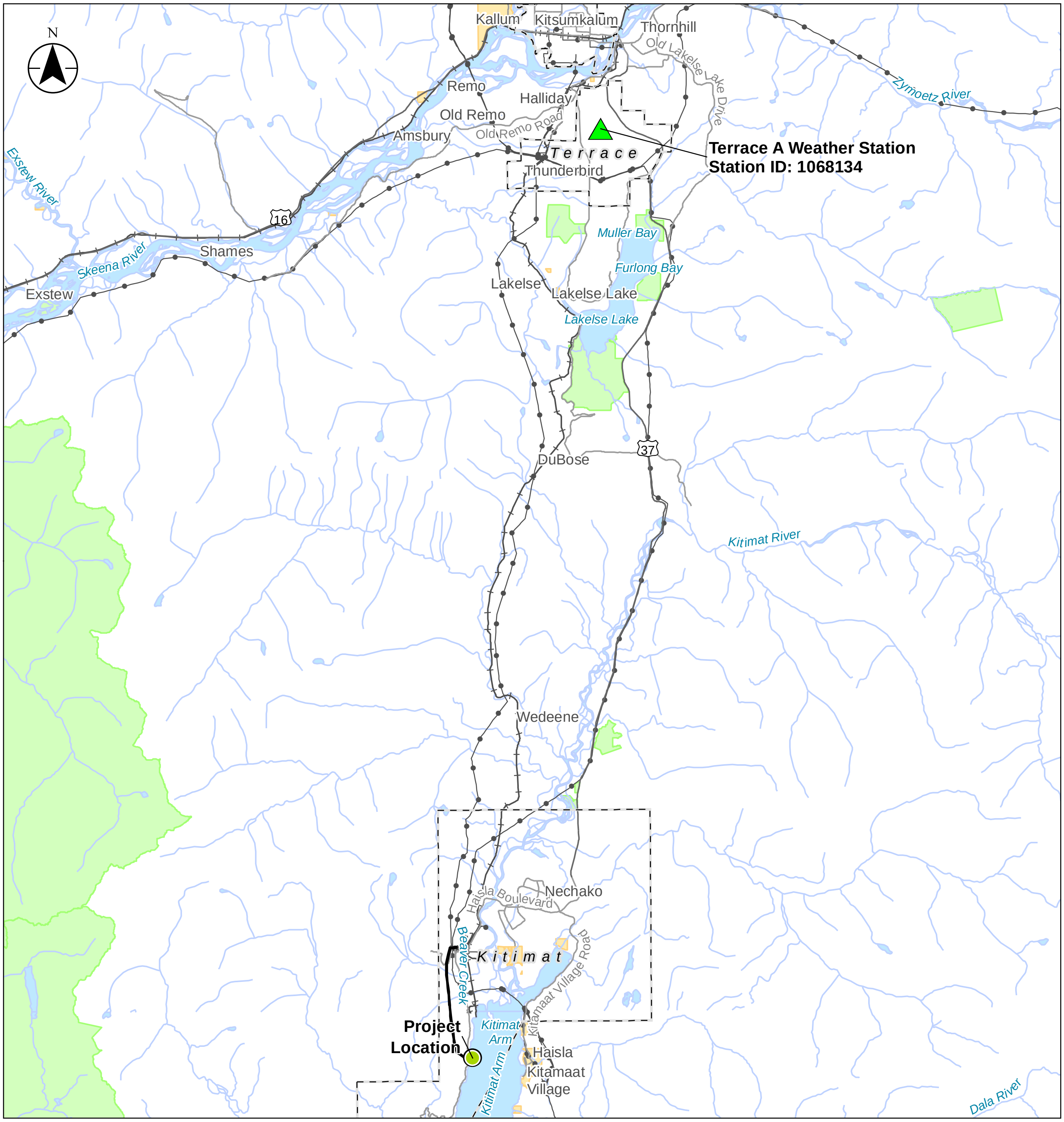
Project Location:
Kitimat,
British Columbia

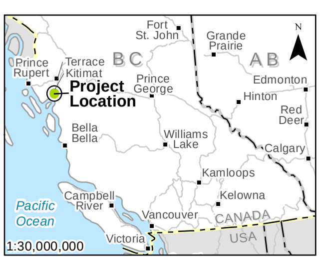
Project Number 123221953
Prepared by KWONG on 20211126
Discipline Review by BBYLHOUWER on 20211126
GIS Review by LTRUDELL on 20211126

Client/Project/Report
Cedar LNG Partners LP
Cedar LNG Project
Strategic Assessment of Climate Change Technical Report

Figure No.
5

Title
Historical Weather Stations Near Kitimat





Highway
Road
Railway
Transmission Line
Watercourse
Waterbody
Reserve Land
Park or Protected Area
District of Kitimat Municipal Boundary

Project Location
Marine Terminal
Weather Station

0 4 8 12 km
1:350,000 (at original document size of 8.5x11)

Notes
1. Coordinate System: NAD 1983 UTM Zone 9N
2. Data Sources: DataBC, Government of British Columbia; Natural Resources Canada; Canadian Hydrographic Service

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Client/Project/Report
Cedar LNG Partners LP
Cedar LNG Project
Strategic Assessment of Climate Change Technical Report

Figure No.
6

Title
Weather Station with Wind Observations Nearest to Kitimat

Table 14 Summary of Weather Monitoring Stations in the Region of Kitimat

Weather Monitoring Station	Latitude	Longitude	Station ID	Data Range (Daily) [% of Data Available]	Elevation
Kitimat 2	54°00'35.000" N	128°42'18.000" W	1064321	1970-2020 [87.8% (Temperature) 90.9% (Precipitation) 91.1% (Snow)]	16.80 m
Kitimat Hatchery	54°02'37.000" N	128°40'56.000" W	1064289	1995-2020 [71.1% (Temperature) 71.7% (Precipitation) 72.3% (Snow)]	11.00 m
Kitimat Townsite	54°03'13.000" N	128°38'03.000" W	1064320	1970-2020 [93.7% (Temperature) 94.8% (Precipitation) 95.1% (Snow)]	98.00 m
Terrace A	54°28'07.000" N	128°34'42.000" W	1068134	1970-2020 [97.9% (Daily Wind) 99.9% (Hourly Wind)]	217.30 m

Future climate projections are based on the Fifth Coupled Model Intercomparison Project (CMIP5) climate projections data. There are nearly 40 global climate models that have contributed to CMIP5, which forms the basis of the latest publications from the Intergovernmental Panel on Climate Change (IPCC). The Pacific Climate Impacts Consortium uses a subset of 24 of these models to produce reliable, high-resolution downscaled climate projections localized to specific areas of interest in Canada (Cannon et al. 2015). In this assessment, the climate projections from a selection of 24 models from the CMIP5 for RCP 8.5 emission scenario were used for the Chester area.

6.3 CLIMATE CHANGE RESILIENCE ASSESSMENT

6.3.1 Timescale of Assessment

Climate projection data was collected for the 2020s (2011 to 2040), 2050s (from 2041 to 2070) and 2080s (2071 to 2100) and are presented in Appendix 1 for additional information. Climate projections for the 2050s were used to estimate future climate conditions for the project.

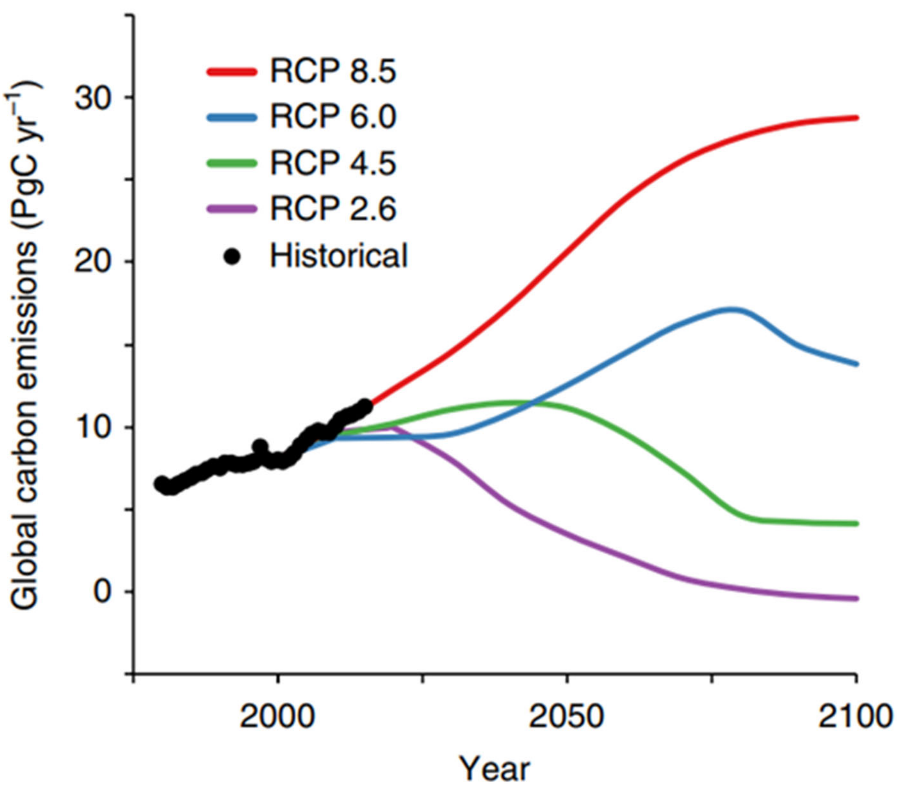
6.3.2 Plausible Climate Scenarios

Climate modeling uses various GHG emissions scenarios, known as Representative Concentration Pathways (RCPs), to project future climate variables under different concentrations and rates of release of GHGs to the atmosphere, as well as different global energy balances.

Various future trajectories of GHG emissions are possible depending on the global mitigation efforts in the coming years. RCPs are established by the IPCC, the international body for assessing the science related to climate change. The IPCC was set up in 1988 by the World Meteorological Organization and United Nations Environment Programme to provide policymakers with regular assessments of the scientific basis of climate change, its impacts and future risks, and options for adaptation and mitigation (IPCC 2014)

The IPCC has set four GHG emissions scenarios through RCPs as shown in Figure 7 (Source: Smith and Myers 2018). RCP 8.5 is internationally recognized as the most pessimistic - “business as usual” GHG emissions scenario. Other GHG emissions scenarios represent more substantial and sustained reductions in GHG emissions. (Figure 7). For example, RCP 4.5 is considered the ‘medium stabilization’ scenario where global mitigation efforts result in intermediate levels of GHG emissions (IPCC 2014).

Figure 7 Historical CO_2 Emissions for 1980-2017 and Projected Emissions Trajectories to 2100 for the Four Representative Concentration Pathway (RCP) Scenarios



Although some progress has been made, current estimates of GHG emissions are still close to following the RCP 8.5 path; therefore, this assessment is based on climate parameters estimated under the RCP 8.5 scenario. The IPCC Special Report on Global Warming of 1.5°C (October 8, 2018) supports the selection of the RCP 8.5 for this assessment.

6.3.3 Climate Profile for Kitimat

Kitimat is located on British Columbia's north coast, a region of temperate rainforest and rugged coastal terrain. Westerly air masses from the north pacific meet the Coast Mountains and lead to high annual precipitation amounts throughout the region, with more snow at higher elevations. The coastal climate results in mild winters and cool summers. Winds are strongly influenced by topography, with north-south flow being dominant in the Kitimat Valley.

Warming is projected to occur in all seasons, with winters warming at a faster rate than summers. Heat waves, when high temperatures occur for at least three days, are relatively rare currently, but are likely to occur annually by the 2050s.

Precipitation is anticipated to increase in the future; however, there are not anticipated to be large changes in heavy precipitation events. Snowfall amounts have been decreasing in recent history and this trend is expected to continue through the 2050s and beyond. However, heavy snowfall events are still likely to occur on a regular basis. Freezing rain events are expected to become slightly less severe in the future.

High winds occur on an annual basis, and these events might occur slightly more frequently in the future.

Forest fires have occurred frequently in the region, leading to potential evacuations or poor air quality. Wildfires are expected to increase slightly in frequency for the region near Kitimat in the future.

6.3.4 Local Knowledge of Historical Climate Events

A summary of some of the information provided is summarized below:

- The region regularly experiences heavy rainfall throughout the year; however, flooding is rare, particularly at the Project site which is far from major rivers.
- There are also periods of heavy snow, with some single events leading to a metre or more of snow. The snow does tend to melt quickly as the winters are relatively mild at the Project site compared to farther inland or at higher elevations.
- The tidal range in Kitimat is approximately 7 m.

6.3.5 Identification of Climate Hazards

Climate hazards used for this resilience assessment were chosen based on experience with previous climate resilience studies for similar types of infrastructure, information provided as part of the Impact Assessment process, and from Project designers. Climate hazards included in the CCRA include:

- Temperature extremes, which can lead to structural damage and increased discomfort for the users
- Freeze-thaw cycles, which can increase maintenance requirements for walkways, roadways, and other hard infrastructure

- Short duration high intensity rainfall, which can cause local flooding, can lead to structural damage of the infrastructure components, and can increase maintenance requirements
- Heavy snowfall, which can lead to the structural damage to buildings and changing maintenance costs for snow clearing
- Freezing rain may impact structural loads, particularly for power and piping assets
- Extreme winds, which can lead to structural damages to the Project or reduce facility operations or site access
- Sea level rise, which can lead to flooding of infrastructure assets

The climate variables selected for this resilience assessment are shown in Table 15. Once the climate parameters are determined, a threshold value is chosen for each climate parameter. The threshold value is normally associated with a consequence or effect on an infrastructure asset and helps establish the probability that a particular climate event will occur. The likelihood that a climate event will occur is based on the historical climate data and climate projections. Table 15 also presents the confidence level associated with the projections for each climate parameter. For example, projections based on global climate models and downscaling of such models are considered:

- Adequate (higher confidence) for general temperature, precipitation projections, and sea level rise
- Less adequate (lower confidence) for extreme parameters
- Less adequate (lower confidence) for high wind events
- Inadequate for combined events (low confidence) such as storms or freezing rain

Combined events are inferred based on other parameters, resulting in lower confidence for projections of combined event parameters. For example, freezing rain is a complex process and the projected prevalence of freezing rain events under future climate conditions is not as well understood as other parameters. Confidence may also refer to whether other studies have been done for the climate events projections in the geographical area.

Table 15 Climate Parameters Selected for Resilience Assessment (2050s-Time Horizon)

Climate Parameter	Threshold	Trend	Confidence Level
Temperature			
High temperature extremes	Days (per year) with maximum temperature greater than or equal to 30°C	Increasing	High
Heat Waves	Three or more consecutive days with temperature greater than 30°C	Increasing	Moderate to High
Extreme cold	Days (per year) with min temps less than or equal to -15°C	Decreasing	Moderate to High
Freeze-Thaw Cycles	Occurrence of 20 freeze-thaw cycles per year	Slightly Decreasing	High
Heating Degree Days (HDD)	Change from current conditions	Decreasing	High
Cooling Degree Days (CDD)	Change from current conditions	Increasing	High
Precipitation			
Short duration heavy rainfall	50 mm of rainfall in 1 hour	Slightly Increasing	Moderate
Long duration heavy rainfall	100 mm of rainfall in 24 hours	Slightly Increasing	Moderate
Heavy snowfall	25 cm or more in 24 hours	Decreasing	Moderate
Extreme Snowfall	90 cm in 24 hours	Decreasing	Moderate
Freezing rain events	20 mm freezing rain event	Slightly Increasing	Low
Wind			
Wind gusts	Wind gusts greater than or equal to 90 km/hr	Slightly Increasing	Low
Wind gusts	Wind gusts greater than or equal to 120 km/hr	Slightly Increasing	Low
Other Climatological Events			
Wildfires	Fires covering more than 200 hectares within 100 km of Kitimat	Slightly Increasing	Moderate
Sea Level Rise	Sea level rise exceeds 50 cm compared to current levels	Increasing	High

6.3.6 Assets under Assessment

The Project infrastructure assets and systems were grouped into the categories presented in Table 16. The list of assets and systems considered were based on project description information provided by Cedar LNG and discussions with Cedar LNG staff.

Table 16 List of Project Components Being Assessed

Asset	Infrastructure Category	Infrastructure Element
Distribution system	Struts	Strut mooring system
		Standalone foundation
	Electricity transmission	Aboveground transmission line
	Feed gas pipeline	Underground piping and valves
		Aboveground piping and valves
	Utilities	Aboveground utilities lines
		Underground utilities lines
FLNG facility	Vessel	Mooring lines
		Decks
	Equipment	Flare
		Processing equipment
	Building	Site access
		Foundation
		Envelope
		Roof
		HVAC system
Water and wastewater management	Equipment	Drainage system
		Piping and valves
		Pumps
Miscellaneous	Site access	Access road
		Stairways
		Snow clearing

6.3.7 Consequence Definitions

Three consequences from climate impacts were considered as part of this assessment. A list of the consequences, along with a brief description of the consequences, is provided in Table 17.

Table 17 Consequence of Impact

Consequence of Impact
Structural Integrity *For example, climate change may lead to premature failure of pavement structure from increased stresses.*
• Component failure • Component deterioration • Increased loading / stress • Change in materials performance
Operations & Maintenance (O&M) *For example, climate change may impact the ability to access worksite for maintenance or require updates to occupational health & safety procedures in maintaining access to worksites or lead to accelerated deterioration of material performance.*
• Occupational safety, health & safety • Reduced serviceability • Increased maintenance / replacement cycles and frequencies • Increased operation and maintenance cost • Change in operational performance
Functionality *For example, climate change may impact the ability of the infrastructure system to deliver at normal levels of service.*
• Violation of policies and procedures • Reduced user comfort • Public/occupant health and safety hazard • Loss of capacity (temporary) • Loss of capacity (permanent)

6.3.8 Consequence of Climate Impacts on Assets

The potential impacts from both extreme events and incremental or slow onset climate parameters on Project assets are presented in Table 18.

Table 18 Summary of Interactions between Climate Parameters and Project Assets

Climate Parameter	Asset Category	Interactions
Average temperature	All	Change in mechanical loads for heating and cooling Change in heat or cold stress to asset components
Extreme heat	All	Change in worker physical stress and site access Change in mechanical loads for heating and cooling
Heat waves	All	Change in worker physical stress and site access Change in mechanical loads for heating and cooling
Heating Degree Days	Vessel	Change in mechanical loads for heating Change in worker comfort
	Process equipment	
	Buildings	
	Site access	
Cooling Degree Days	Vessel	Change in mechanical loads for cooling Change in worker comfort
	Process equipment	
	Buildings	
	Site access	
Cold Days	All	Change in mechanical loads for heating Change in worker comfort
Freeze-thaw cycles	Struts	Change in wear on structural systems
	Electricity transmission	
	Feed gas pipeline	
	Utilities	
	Buildings	
	Site access	
Average annual precipitation	Buildings	Change in drainage capacities to avoid localized flooding
	Water management	
Long-duration heavy rainfall	Buildings	Change in drainage capacities to avoid localized flooding
	Water management	
	Site access	
Short-duration heavy rainfall	Buildings	Change in drainage capacities to avoid localized flooding
	Water management	
	Site access	
Heavy Snowfall	Vessel	Change in snow clearing requirements Change in structural loads
	Buildings	
	Site access	

Table 18 Summary of Interactions between Climate Parameters and Project Assets

Climate Parameter	Asset Category	Interactions
Extreme snowfall	Vessel	Change in snow clearing requirements Change in structural loads
	Electricity transmission	
	Buildings	
	Site access	
Freezing rain	Struts	Change in structural loads Change in site accessibility from slippery conditions
	Electricity transmission	
	Utilities	
	Vessel	
	Process equipment	
	Buildings	
	Site access	
High wind gusts	Struts	Change in structural loads Change in access to/from the FLNG facility
	Electricity transmission	
	Utilities	
	Vessel	
	Process equipment	
	Buildings	
Wildfires	Electricity transmission	Change in exposure to thermal radiation Change in site access from fires in region Change in air quality
	Buildings	
	Site access	
Sea level rise	All	Change in site access Change in water loads to coastal structures

6.3.9 Climate Risk Analysis

Risk rating is defined as the product of two ratings.

Risk Rating = Likelihood Rating x Consequence Rating

- **Likelihood Rating** represents the probability (likelihood) of occurrence of a climate event above a selected threshold, ranging from 1 (very low) to 5 (very high)
- **Consequence Rating** is a measure of the impacts on the infrastructure asset or component should the climate event occur, ranging from 1 (very low) to 5 (very high)

Risks are evaluated under current climate conditions to establish a baseline. Future risks are assessed considering future (projected) climate changes. The condition of the infrastructure in the future climate is assumed to be well maintained and thus will maintain a similar level of resilience to climate events. Deterioration of the Project components is not considered in the selected lifespan of this assessment.

6.3.9.1 Likelihood Scores for Climate Events

A likelihood score estimates how likely a climate event will occur. For this assessment, a rating scale of 1 to 5 for the likelihood of a climate event occurring was adopted and is shown in Table 19. The likelihood score is assigned based on the evaluation of historical occurrences and future climate projections for each climate variable.

The probability ratings for the selected climate parameters are presented in Table 20.

Table 19 Likelihood Ratings Based on Climate Event Occurrence

Occurrence	Qualitative Descriptor	Descriptor	Rating *
Less than once every 50 years	Very Low	Not likely to occur or become critical/beneficial or during project lifetime	1
At least once every 30 years	Low	Likely to occur once during project lifetime	2
At least once every 10 years	Moderate	Likely to occur a few times during the project lifetime	3
Occurs more than once per ten years	High	Likely to occur many times during the project lifetime	4
Occurs at least every year	Very High	Likely to occur every year during the project lifetime	5

NOTE:
* For average changes, including average temperature and average precipitation, a rating of 3 indicates no change in average conditions, while values below 3 or above 3 indicate decrease or increases in those average quantities, respectively

Table 20 Current and Future Likelihood Rating for Selected Climate Parameters

Climate Parameter	Climate Threshold	Likelihood of Occurring		
		Baseline Climate	Future Climate Projections: 2050s (2041-2070)	Future Climate Projections: 2080s (2071-2100)
Average annual temperature	Change from baseline average*	3	4	5
Extreme heat	Annual occurrence of maximum daily temperature of 34°C or more	1	4	5
Heatwaves	Frequency of occurrence of heatwave events (three consecutive days or more with Tmax ≥ 30°C)	4	4	5
Heating Degree Days	Change from baseline average	3	4	4
Cooling Degree Days	Change from baseline average	3	4	4
Cold Days	Days (per year) with min temps less than or equal to -15°C	5	5	4
Freeze-thaw cycles	Occurrence of 30 freeze-thaw cycles per year	5	5	4
Average annual precipitation	Change from baseline average*	3	4	4
Long-duration rainfall	100 mm in 24 hours	4	4	5
Short-duration (high intensity) rainfall	50 mm in 1 hour	1	1	1
Heavy Snowfall	25 cm in 24 hours	5	4	3
Extreme snowfall	90 cm in 24 hours (1-25 event)	2	2	1
Freezing rain	20 mm event	2	2	1
High wind gusts	Wind gust events of 90 km/h or more	4	4	4
High wind gusts	Wind gust events of 120 km/h or more	2	2	2
Wildfires	Change from baseline average, based on flash density per square kilometre, per year	4	4	4
Sea level rise	Change of more than 50 cm above baseline average	1	1	5

6.3.9.2 Consequence Score of Climate Impacts

With the selected climate events likelihood scores determined for future climate conditions, a consequence score must also be determined. The consequence scoring system used for this assessment is shown in Table 21. These ratings are based on the degree to which a climate event causes a loss or disruption of service. For example, taking a component such as the walkway to the FLNG facility - a minor rating would mean that the walkway may not operate in a desired range for comfort requirements. A very high rating may require the closure of the walkway for a period of time. Service in the context of the Project is defined as the ability of the FLNG facility to operate at full capacity or accept LNG carriers for export.

Table 21 Consequence Ratings

Consequence Score	Criteria / Comments
1	Very Low - No serious impact from a weather event, routine maintenance will repair any damage.
2	Low - Some extra cost repairs and maintenance require but can be handled by operations staff. No loss of service.
3	Moderate - Some damage to infrastructure. Extra costs and labour required to complete repairs. Some specialized labour or equipment required to complete repairs. Some loss of service.
4	High - Significant damage to infrastructure. Significant extra costs and labour required to complete repairs. Specialized labour or equipment required to complete repairs. Significant loss of service.
5	Very High - Complete loss of the asset after a weather event. Repair not possible. Replacement of component required. Extended period of loss of service.

6.3.9.3 Risk Analysis Procedure

Using the equation “Risk Rating = Likelihood Rating x Consequence Rating” provides numerical risk ratings from 0 to 25 as shown in Figure 8.

Figure 8 Risk Ratings - Evaluation Matrix Adapted from Climate Lens General Guidance (Infrastructure Canada, 2019)

Consequence							
	Very High	5	5	10	15	20	25
	High	4	4	8	12	16	20
	Moderate	3	3	6	9	12	15
	Low	2	2	4	6	8	10
	Very Low	1	1	2	3	4	5
			1	2	3	4	5
			Very Low	Low	Moderate	High	Very High
			Likelihood				

In Table 22, risk ratings are explained with suggested risk treatments as per the Climate Lens General Guidance.

Table 22 Risk Classification. Adapted from Climate Lens General Guidance

Risk Classification	Risk Rating	Description of Risk	Risk Treatment
Negligible	1,2	• No permanent damage • No service disruption occurs	Risks do not require further consideration
Low	3,4,5,6	• Minor asset/equipment damage • Minor service disruption may be possible • No permanent damage • Minor repairs or restoration expected	Controls likely, but not required
Moderate	8,9	• Expected limited damage to asset or to equipment components • Minor repairs and some equipment replacement may be required • Brief service disruption may be possible	Some controls required to reduce risks to lower levels. Risk to be monitored for changes over time.
High	10,12, 15,16	• May result in significant permanent damage; or loss of asset or component that may require complete replacement • More lengthy service disruption may be possible	High priority control measures required
Extreme	20,25	• May result in significant permanent damage; or loss of asset or component that may require complete replacement • Significant service disruptions may be possible	Immediate controls required

6.3.9.4 Risk Analysis Results and Adaptation Considerations

Climate risks for the current and future climate in the 2050s were reviewed. A summary of the fraction of low, medium, and high risks for the current and future climate is shown in Table 23. Most asset-climate interactions were rated as negligible or low risks for both the current and future climate. A noticeable change between the current and future climate were some low risks becoming moderate risks in the 2050s. The majority of the high climate risks for the current and future climate were associated with increasing temperatures, freeze-thaw cycles, cold days, and wildfires. Snowfall was found to be high risk for the current climate, but is expected to be a moderate risk in the future as snowfall is expected to decline in the future. Changing heating degree-days and cooling degree-days were found to be a high risk for the future climate through substantial changes to the potential heating and cooling requirements for process equipment.

Table 23 Distribution of Risk Levels for Climate Change Resilience Assessment

Risk Level	Fraction of Total Risk Count (%)	
	Current Climate	Future Climate (2050s)
Negligible	20	13
Low	52	47
Moderate	10	22
High	17	18

A summary of the moderate and high risks, including potential adaptation measures to be considered during facility design, is shown in Table 24.

6.3.9.5 Pursuit of Multiple Benefits

This assessment has identified that many climate risks to the Project can be addressed through adjusting design criteria for future climate conditions in the detailed design stages of the Project and establishing Operations and Maintenance(O&M) policies and procedures. Making design adjustments early in the design stages of the Project is the most cost-effective approach, as having to make changes later in the project life cycle often results in higher costs and project schedule delays. For new construction of the project components, the opportunity exists to incorporate design criteria specific to known future climate risks into the Project's procurement to ensure the construction contractor for the Project takes future climate parameters into account and to establish effective O&M policies and practices that work for the site in a changing climate.

It is outside the scope of this climate resilience assessment to complete detailed review of existing design criteria and O&M policies at other similar infrastructure or to comment on potential policies for the proposed new construction. However, this climate assessment may motivate internal development of design criteria adjustments and O&M policies with a focus to adapting to climate risks for the Project as these have been identified in this assessment.

6.3.9.6 Avoidance of Unintended Consequences

At the current stage of Project, it is too early to fully consider the unintended consequences of risk transference or mitigation strategies. Stantec recommends this principle to be considered in detail during the design-build of the Project. In general, O&M measures for climate adaptation are not GHG intensive. For potentially energy- and GHG-intensive risk mitigation strategies, Stantec recommends incorporating design targets for the reduction of operational GHGs to avoid long-term unintended environmental consequences.

Table 24 Summary of High Risks for Current and Future Climate, and Climate Adaptation Considerations

Climate Parameter	Asset	Climate-Asset Interaction	Consequence Score	Current Climate	Future Climate	Adaptation Considerations
Average Temperature	Processing Equipment	Changes heating and cooling loads	3	Moderate	High	Review design criteria for processing equipment to confirm if future temperature climate conditions are considered. Increase routine maintenance for cooling equipment that may be under increased stress
	HVAC Systems	Changes heating and cooling loads	4	High	High	
Cooling Degree Days	HVAC Systems	Potential increasing cooling requirements	3	Moderate	High	
Cold Days	Processing Equipment	Could reduce effectiveness or flexibility of strut	2	High	High	
	HVAC Systems	More heating requirements	2	High	High	
	Piping Systems	Can make piping systems more brittle	2	High	High	
Freeze-Thaw Cycles	Struts	Increasing wear on components	2	High	High	Increase routine maintenance for cooling equipment that may be under increased stress
	Flare	Increasing wear on components	2	High	High	
	Processing Equipment	Increasing wear on components	2	High	High	
	HVAC Systems	Increasing wear on components	2	High	High	
	Piping Systems	Increasing wear on components	2	High	High	
	Stairways	Increasing wear on components	2	High	High	

Table 24 Summary of High Risks for Current and Future Climate, and Climate Adaptation Considerations

Climate Parameter	Asset	Climate-Asset Interaction	Consequence Score	Current Climate	Future Climate	Adaptation Considerations
Snowfall	Site Access	Delays in site access	2	High	Moderate	Confirm structural design incorporates snowfall levels, including heavy snowfall events
	Roof	Can cause dangerous loads on roofs	2	High	Moderate	
Wind Gusts 90 km/h	Struts	Increasing wear on strut components	3	High	High	Confirm that designs consider high frequency of high wind loads. Develop operational plan for high wind conditions.
	Electricity Transmission	potential for power outages during high winds	3	High	High	
	Above-Ground Utilities	potential interruptions to utility services	3	High	High	
	Building Envelopes	damage to building structure	3	High	High	
	Roofs	damage to roofs	3	High	High	
Wildfire	All Land-side Systems	damage or restricted site access to land-based facilities	3	High	High	Consider Emergency Response Plan for wildfire, including considerations for ventilation for buildings.

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APPENDIX 1

Climate Profile Overview

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Kitimat – Climate Profile

Cedar LNG Project

November 2021

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1.0 INTRODUCTION

1.1 DESCRIPTION OF CLIMATE PROFILES

Climate is usually defined as the "average weather," or more rigorously, as the statistical description in terms of the mean and variability of meteorological variables such as temperature, precipitation and wind over a period of time. Climate profiles are important tools that describe what climate trends have been occurring in recent history (i.e., over the last 30 years or longer), and also describe future climate conditions to help inform the planners, stakeholders and decision makers to manage the climate change risks and plan for the appropriate adaptation measures. Climate profiles rely on the historical climate record (usually in the form of meteorological data measured at weather stations) to describe climate from recent history, and on climate projections (developed by global climate models or GCMs). The historical climate profile puts future climate projections into context: the performance of the infrastructure from the past can be compared to both historical and future climate to better understand what (if any) adaptation measures should be implemented to ensure better performance in the future.

When developing a profile of the historic climate of an area, the most valuable data is typically temperature, precipitation, and wind. Meteorological data from the last 30 years is preferred to help give a representative estimate of the climate of recent history at a given location – though longer periods are of even greater benefit in that they add even more to the story of an area's historical climate. Environment and Climate Change Canada (ECCC) provides the largest database of observational historical climate data in Canada. In addition to assembled climate data from weather stations, gridded data products are available and provide additional climate data resources. These gridded data products include the NRCANmet gridded dataset, produced by Natural Resources Canada (NRCan), which provides daily maximum and minimum temperature and total precipitation data on a ~10 km grid resolution over Canada for the 1950-2013 time period (Hopkinson, 2011) (McKenney, 2011.). Although observational data from a weather station is preferable, gridded datasets such as NRCANmet are well accepted and researched. While not a directly measured data set, NRCANmet is a peer-reviewed, gridded interpolation of the daily weather conditions and historical climate of any land-based location in Canada. As such, the NRCANmet datasets are well accepted and can provide reasonable approximations for locations when historic data is not inadequate for climate assessment.

Climate projections are descriptions of the future climate, and are most often collected from GCMs developed by many organizations across the world. These GCMs are complex, in that they all rely on many different assumptions about how they work (i.e., they focus more on different physical phenomena to estimate future climate, whether it be greenhouse gas (GHG) concentrations in the atmosphere or absorption of solar radiation by the ocean) and also on what will happen in the future. Since different GCMs focus more than others on different physical phenomena, there is a noticeable difference in the future climate that is predicted. Therefore, it is not recommended to rely only on one or two of these GCMs to estimate future climate. Instead, an average of several GCMs tends to give a more reliable estimate of future climate. There are nearly 40 GCMs that have contributed to the Fifth Coupled Model

Intercomparison Project (CMIP5), which forms the basis of the latest publications from the Intergovernmental Panel on Climate Change (IPCC). The Pacific Climate Impacts Consortium (PCIC) has taken a subset of 24 of these models to produce reliable, high-resolution downscaled climate projections localized to specific areas of interest in Canada (A.J. Cannon, 2015).

In addition to the physics of the GCMs, global progress towards meeting GHG emissions targets is also a large source of uncertainty in future climate projections. There are four Representative Concentration Pathways (RCP)[1] scenarios adopted by the Intergovernmental Panel on Climate Change (IPCC) that are based on various future greenhouse gas concentration scenarios. This climate profile will focus on the "business as usual" greenhouse gas concentrations scenario, RCP 8.5. Current global GHG concentrations are closer to following the RCP 8.5 pathway, despite global agreements/targets for GHG emissions reductions.

The IPCC is the international body for assessing the science related to climate change. The IPCC was set up in 1988 by the World Meteorological Organization (WMO) and United Nations Environment Programme (UNEP) to provide policymakers with regular assessments of the scientific basis of climate change, its impacts and future risks, and options for adaptation and mitigation.

IPCC assessments provide a scientific basis for governments at all levels to develop climate related policies, and they underlie negotiations at the UN Climate Conference – the United Nations Framework Convention on Climate Change (UNFCCC). The assessments are policy-relevant but not policy-prescriptive: they may present projections of future climate change based on different scenarios and the risks that climate change poses and discuss the implications of response options, but they do not tell policymakers what actions to take.

1.2 CLIMATE PROFILE FOR KITIMAT

A climate profile was required for the region of Kitimat to assess the climate risks of [Infrastructure type]. The climate profile for the region of Kitimat (Figure 1 and 2) required a review of available historical observed weather data and climate projection data for the region. When developing a profile of the historic climate of an area, the most valuable data is typically temperature, precipitation, and wind data collected from nearby weather stations. There are 4 Environment and Climate Change Canada (ECCC) weather stations for the region of Kitimat which ranges from hourly to monthly time step. Some of them have the same station name but cover different time range, some others have less than 30 years of record. A summary of the weather stations with the most complete historical datasets is shown in Table 1 and Figure 1,2 and will be used in analysis.

As shown in Table 1, four observational stations are identified for use to establish the historical climate conditions for the region of Kitimat. These are KITIMAT 2 (Station ID: 1064321) and Kitimat Hatchery (Station ID: 1064289), Kitimat Townsite (Station ID: 1064320) and Terrace A (Station ID: 1068134). In consideration of data availability and the location of the project asset, the Kitimat Townsite and Terrace A

[1] RCP: Representative Concentration Pathways – a greenhouse gas concentration (not emissions) trajectories adopted by the Intergovernmental Panel on Climate Change (IPCC) for its fifth Assessment Report (AR5) in 2014.

weather stations are chosen to represent the climate baseline of the region of Kitimat, temperature, precipitation and snowfall variables will be taken from the Kitimat Townsite weather station, while hourly and daily wind data will be taken from the Terrace A weather station.

Figure 1 Historical Weather Stations in the region of Kitimat

Figure 2 Historical Weather Stations in the region of Kitimat

Table 1 Summary of weather monitoring stations in the region of Kitimat

Weather Monitoring Station	Latitude	Longitude	Station ID	Data Range (Daily) [% of Data Available]	Elevation
Kitimat 2	54°00'35.000" N	128°42'18.000" W	1064321	1970-2020 [87.8% (Temperature) 90.9% (Precipitation) 91.1% (Snow)]	16.80 m
Kitimat Hatchery	54°02'37.000" N	128°40'56.000" W	1064289	1995-2020 [71.1% (Temperature) 71.7% (Precipitation) 72.3% (Snow)]	11.00 m
Kitimat Townsite	54°03'13.000" N	128°38'03.000" W	1064320	1970-2020 [93.7% (Temperature) 94.8% (Precipitation) 95.1% (Snow)]	98.00 m
Terrace A	54°28'07.000" N	128°34'42.000" W	1068134	1970-2020 [97.9% (Daily Wind) 99.9% (Hourly Wind)]	217.30 m

The time horizons of 1981-2010 were selected as current conditions for the Kitimat region establishing the baseline. The climate for the 2020s (time horizon of 2011 to 2040) is presented to evaluate how recent trends correlate with the projections in the near future. The 2050s (2041 to 2070) and 2080s (2071 to 2100) time horizons are presented as longer-term climate projections, which will highlight the variation between the various future GHG scenarios presented to help inform the stakeholders and decision-makers of the climate risks to the infrastructure in the region. The projected climate values represent the projected average over a 30-year time period in the future.

2.0 TEMPERATURE

2.1 MEAN TEMPERATURE

Summaries of mean historical temperature averaged from 1981 through 2010 for the Kitimat region and average change in mean temperature from the baseline are shown in Table 2. Annual and seasonal temporal averages for daily mean temperature in the Kitimat region are shown in Figure 4 and Figure 5. Annual and seasonal mean temperature is projected to increase from the 1981-2010 baseline with the greatest changes (+3.8°C) occurring in the winter months.

Table 2 Average Change in Mean Temperature from Baseline (RCP 8.5) in Kitimat

Season	Mean Temperature Climate Average 1981-2010 (°C)	Average Mean Temperature (Change) from 1981-2010 Baseline in °C		
		2020s	2050s	2080s
Annual	7.3	7.7 (+0.4)	9.15 (+1.9)	10.95 (+3.7)
Winter	-0.9	-0.3 (+0.6)	1 (+1.9)	2.95 (+3.8)
Spring	7.0	7.25 (+0.3)	8.7 (+1.7)	10.4 (+3.4)
Summer	15.9	15.9 (+0.0)	17.55 (+1.6)	19.4 (+3.5)
Fall	7.1	7.85 (+0.7)	9.2 (+2.1)	10.85 (+3.7)

Figure 3 Annual and Seasonal Temporal Averages - Mean Daily Temperature (RCP8.5) in Kitimat Region

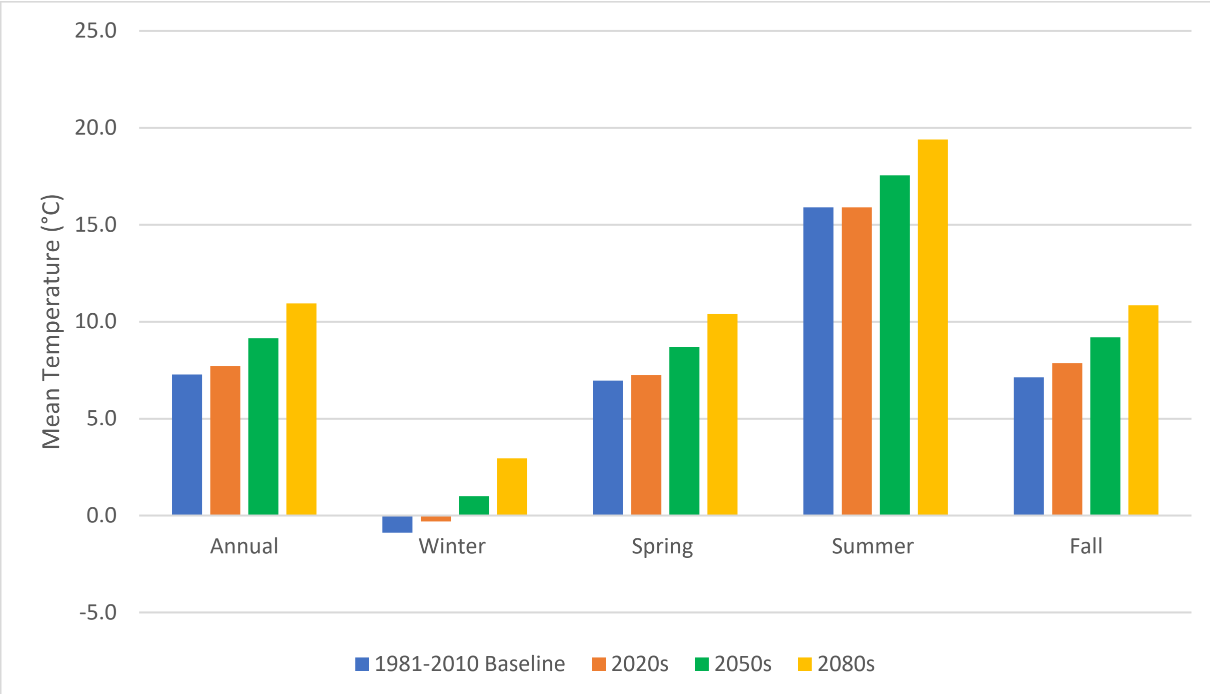
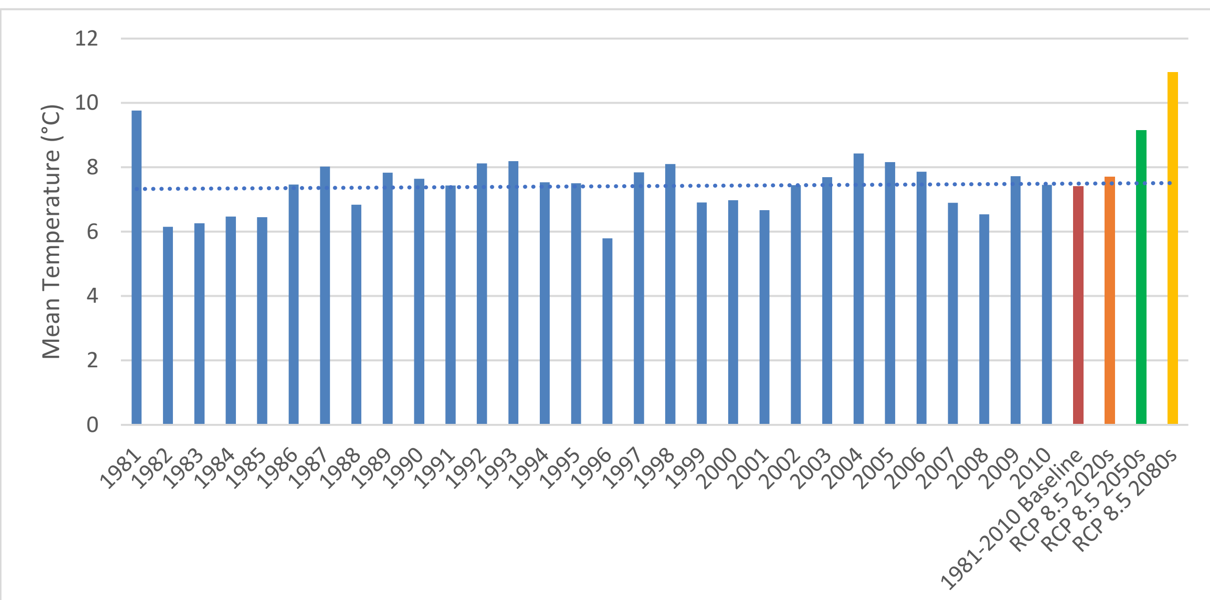


Figure 4 Annual Temporal Average - Mean Daily Temperature (RCP 8.5) in Kitimat Region



2.2 MAXIMUM TEMPERATURE

2.2.1 Annual and Seasonal Average

Summaries of maximum historical temperatures averaged from 1981 through 2010 for the Kitimat region and average change in maximum temperature from the baseline are shown in Table 3. Annual and seasonal temporal averages for daily maximum temperature in the region are shown in Figures 6 and 7. The maximum annual and seasonal temperature is projected to increase from the 1981-2010 baseline with the greatest increase occurring in the summer and fall months (+3.6°C).

Table 3 Average Change in Maximum Temperature from Baseline (RCP 8.5) in Kitimat Region

Season	Maximum Temperature Average 1981-2020 (°C)	Average Change in Maximum Temperature from 1981-2010 Baseline (°C)		
		2020s	2050s	2080s
Annual	11.0	11.4 (+0.4)	12.8 (+1.8)	14.6 (+3.6)
Winter	1.6	2 (+0.4)	3.2 (+1.6)	5.0 (+3.4)
Spring	11.5	11.7 (+0.2)	13.1 (+1.6)	14.8 (+3.3)
Summer	20.9	20.8 (+-0.1)	22.5 (+1.6)	24.5 (+3.6)
Fall	10.2	10.9 (+0.7)	12.2 (+2.0)	13.8 (+3.6)

Figure 5 Annual and Seasonal Temporal Averages – Maximum Daily Temperature in Kitimat Region

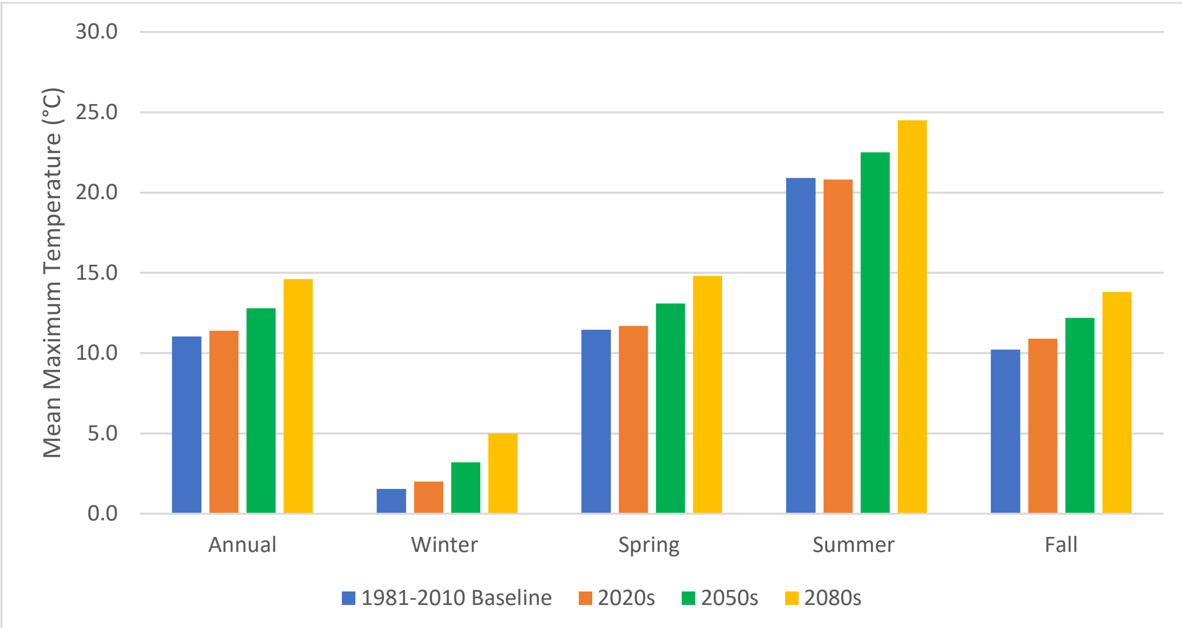
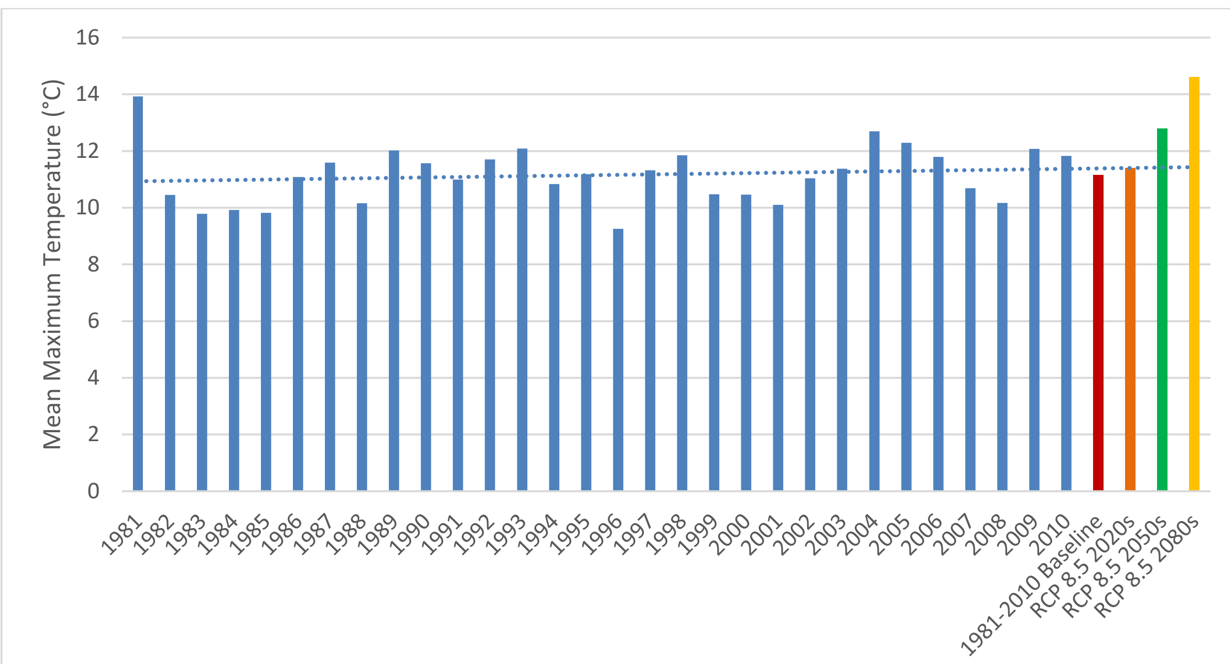


Figure 6 Annual Daily Maximum Averages (RCP 8.5) in Kitimat Region



2.2.2 Extreme Maximum Temperature Frequency

Extreme heat can negatively affect some infrastructure. The average number of days with daily maximum temperatures greater than or equal to 34°C and 30°C in the Kitimat region is shown historically and for future time periods in Table 4 and Table 5, respectively. The frequency of extreme high temperatures is projected to increase for the region.

Table 4 Occurrence of Maximum Daily Temperature ≥34°C, Kitimat Region (RCP 8.5)

Average Annual Number of Days with Max. Temp ≥ 34°C			
1981-2010 Baseline	2020s	2050s	2080s
0.0	0.2	0.7	2.0

Table 5 Occurrence of Maximum Daily Temperature ≥30°C, Kitimat Region (RCP 8.5)

Average Annual Number of Days with Max. Temp ≥ 30°C			
1981-2010 Baseline	2020s	2050s	2080s
0.8	2.0	4.7	10.0

2.3 MINIMUM TEMPERATURE

2.3.1 Annual and Seasonal Average

Summaries of mean minimum historical temperature averaged from 1981 through 2010 for Kitimat region and average change in minimum temperature from the baseline are shown in Table 6. Annual and seasonal temporal averages for daily minimum temperature in the region are shown in Figures 8 and 9. The minimum annual and seasonal temperature is projected to increase from the 1981-2010 baseline with the greatest increase (+4.1°C) occurring in the winter months.

Table 6 Average Change in Minimum Temperature from Baseline (RCP 8.5) in Kitimat Region

Season	Minimum Temperature Average 1981-2020 (°C)	Average Change in Minimum Temperature from 1981-2010 Baseline (°C)		
		2020s	2050s	2080s
Annual	3.5	4 (+0.5)	5.5 (+2.0)	7.3 (+3.8)
Winter	-3.2	-2.6 (+0.6)	-1.2 (+2.0)	0.9 (+4.1)
Spring	2.5	2.8 (+0.3)	4.3 (+1.8)	6 (+3.5)
Summer	10.9	11 (+0.1)	12.6 (+1.7)	14.3 (+3.4)
Fall	4.0	4.8 (+0.8)	6.2 (+2.2)	7.9 (+3.9)

Figure 7 Annual and Seasonal Temporal Averages – Minimum Daily Temperature in Kitimat Region

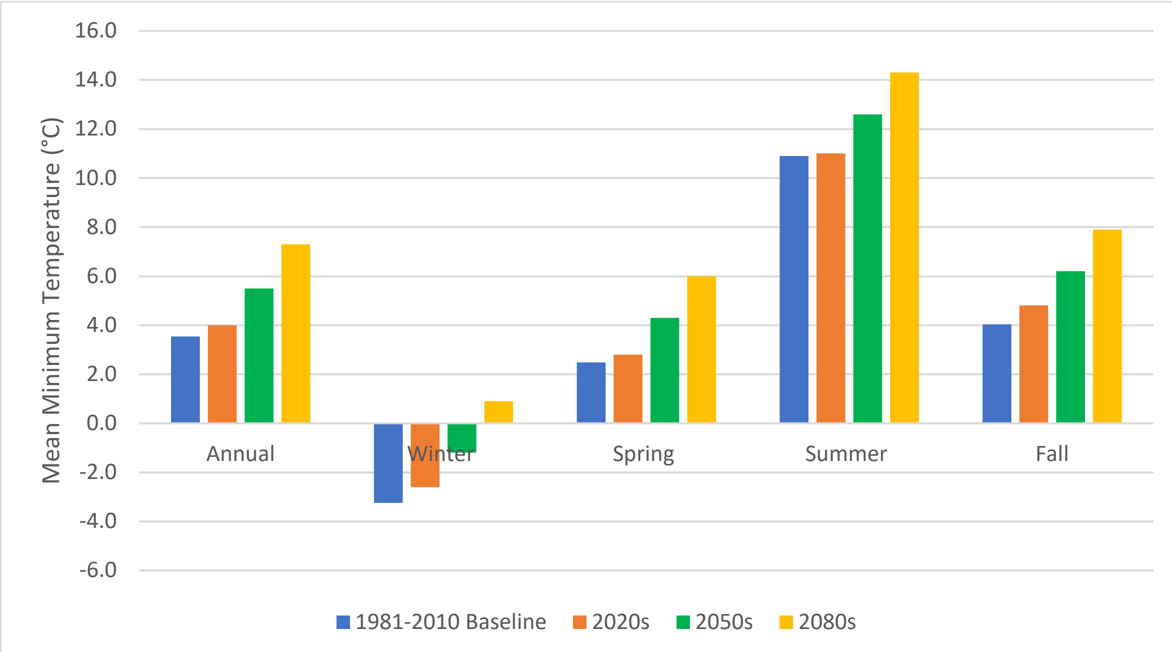
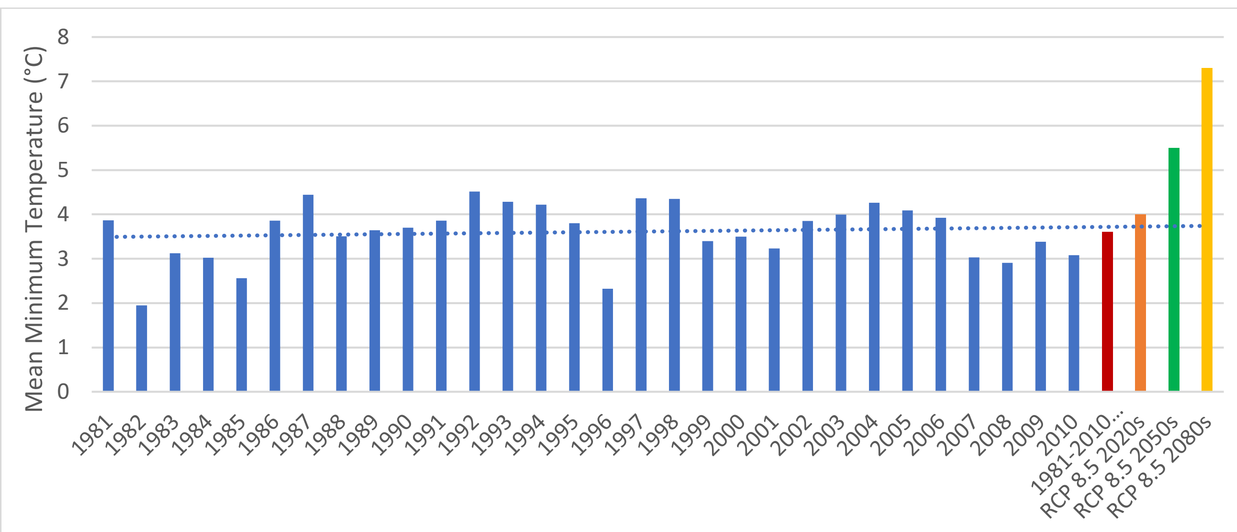


Figure 8 Annual Temporal Average – Minimum Daily Temperature (RCP 8.5) in Kitimat Region



2.3.2 Extreme Minimum Temperature Frequency

It can also be useful to view projected increases in temperatures as the change in the occurrence of days with a temperature lower than a certain extreme cold threshold. The climate projections for the occurrence of days with temperatures less than -15°C are presented in Table 7. The frequency of extreme minimum temperatures is projected to decrease for the Kitimat region.

Table 7 Occurrence of Minimum Temperature ≤ -15°C, Kitimat Region (RCP 8.5)

Average Annual Number of Days with Min. Temp ≤ -15°C			
1981-2010 Baseline	**2020s**	**2050s**	**2080s**
11.0	3.7	1.4	0.4

3.0 PRECIPITATION

3.1 TOTAL ANNUAL & SEASONAL ACCUMULATION

Total annual and seasonal precipitation in the Kitimat region for the recent historical period (1981 – 2010) for the region and percent change in total precipitation from the baseline are shown in Table 8. Total annual and seasonal precipitation in the Kitimat region for future climate periods is shown in Figures 8 through 10. Annual, winter, spring and fall precipitation is projected to increase in Kitimat region with the largest percentage changes (+22.9%) in winter while summer precipitation is projected to decrease (- 6.6%) under RCP 8.5 in 2080s.

Table 8 Average Percent Change in Total Precipitation from Baseline (RCP 8.5) in Kitimat Region

Season	Mean Total Precipitation Average 1981-2010 (mm)	Projected Percent Change in Total Precipitation from 1981-2010 Baseline (%)		
		2020s	2050s	2080s
Annual	2111.7	7.2%	11.0%	17.7%
Winter	693.5	14.2%	15.1%	22.9%
Spring	371.0	3.4%	7.6%	13.3%
Summer	230.5	1.0%	-2.6%	-6.6%
Fall	816.6	4.8%	12.7%	22.1%

Figure 9 Average Annual Total Precipitation in Kitimat Region

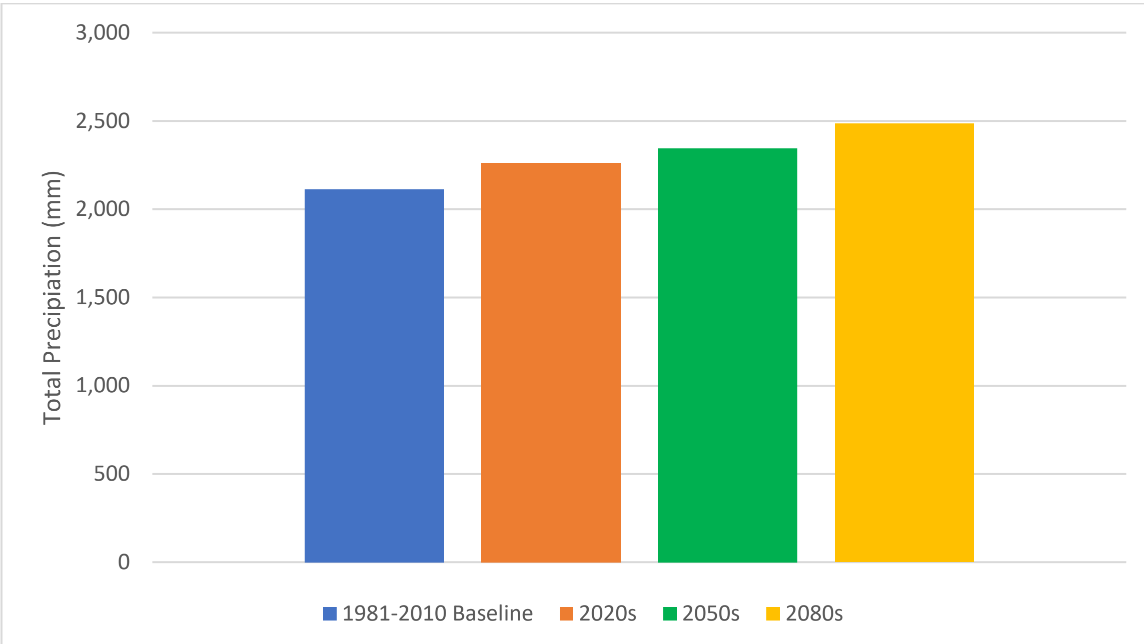


Figure 10 Average Seasonal Total Precipitation (RCP 8.5) in Kitimat Region

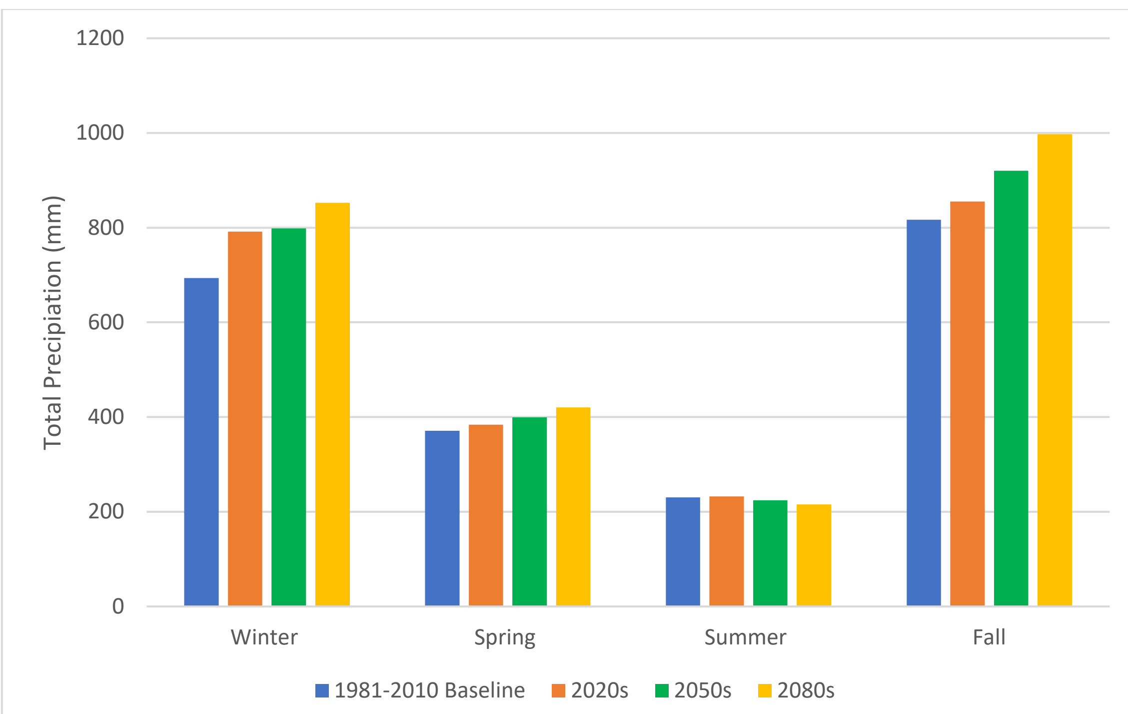
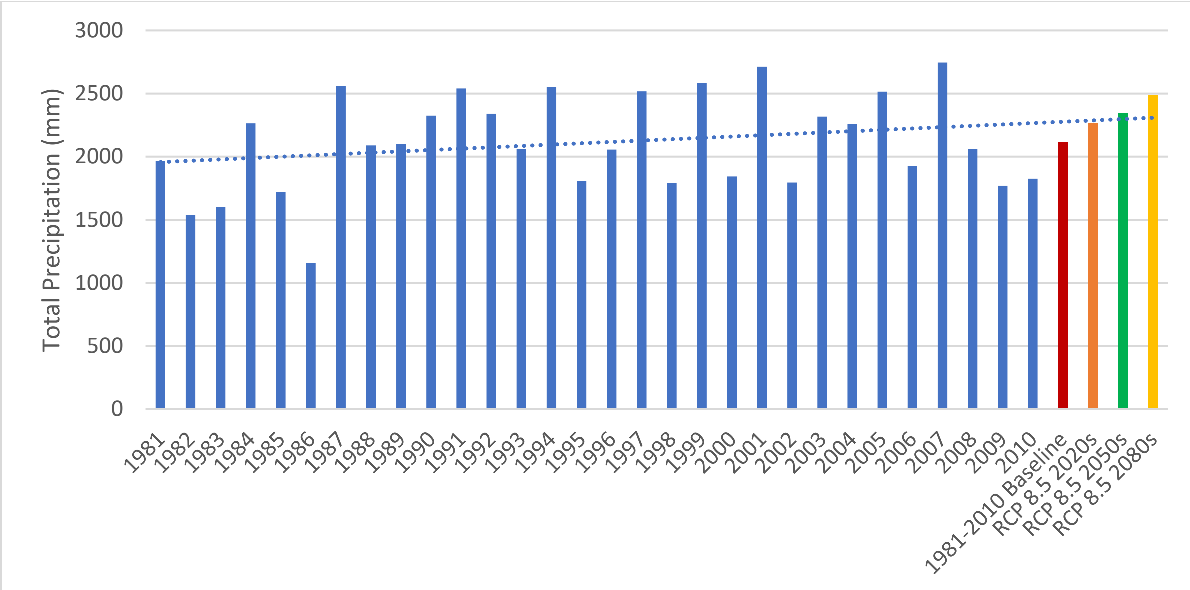


Figure 11 Average Annual Precipitation Temporal Total (RCP 8.5) in Kitimat Region



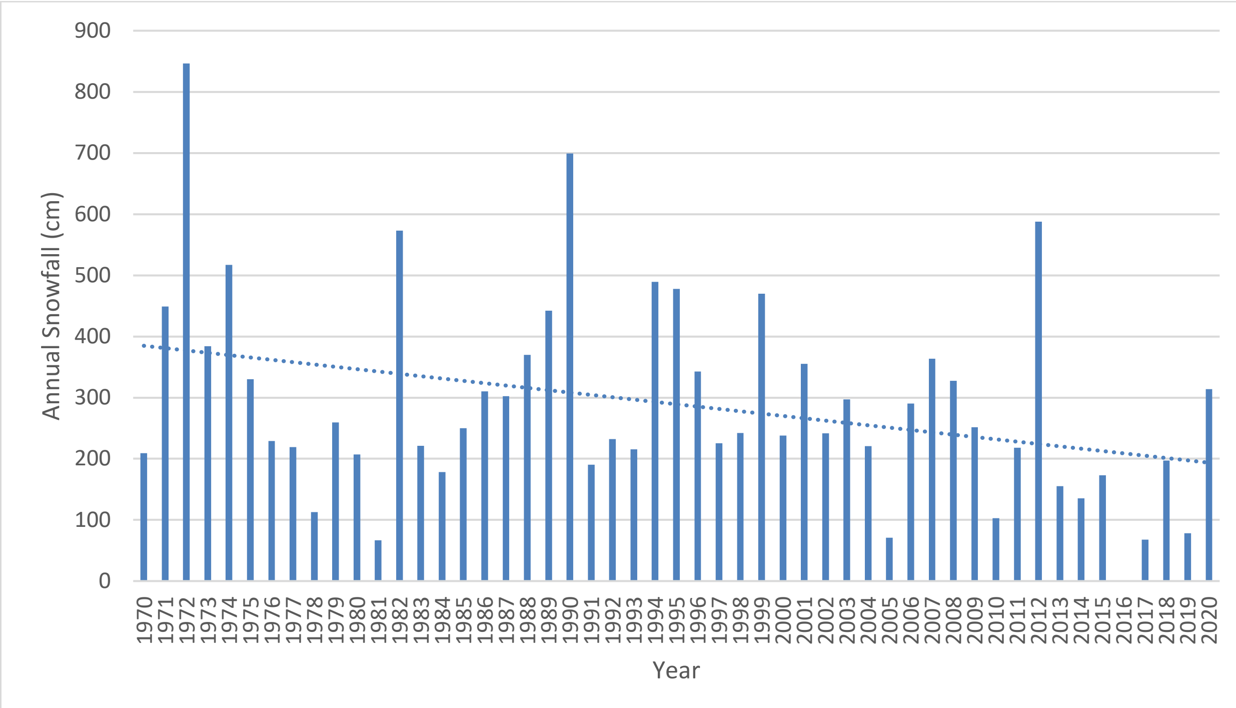
3.2 SNOW

The historical occurrences of snowfall in the Kitimat region based on the observations of ECCC weather stations for 1970-2020 are shown in Table 9 and Figure 13. Overall, snowfall is projected to decrease in the region under RCP 8.5. However, large events will remain possible under climate change due to cold air outbreaks and storm tracks.

Table 9 Days with snowfall in Kitimat Region, 1981-2010 Canadian Climate Normals (Environment Canada)

Snowfall	Days/year
≥ 0.2 cm	32.2
≥ 5 cm	16.6
≥ 10 cm	9.9
≥ 25 cm	2.7

Figure 12 Historical Annual Snowfall in the region of Kitimat



3.3 INTENSITY-DURATION-FREQUENCY (IDF)

Evaluating historic and projected intensity-duration-frequency (IDF) data provides insight into how the intensity, duration, and frequency of precipitation events will change under future climate conditions. IDF data relates short-duration, high rainfall intensity with its frequency of occurrence. When IDF data is not available from the representative weather station within the climate zone, "ungauged" historical IDF data, calculated through interpolation between Environment Canada weather stations in the region can be used. The Kitimat weather station (ID: 1064288) provides 26 years of record of IDF data, covering the 1966-1992 time period. Therefore, for the Kitimat region, the historical IDF data provided to evaluate the future changes in intensity, duration, and frequency of precipitation events will be taken from the ungauged historical IDF data due to poor weather station data availability. The chosen coordinates in Kitimat are as follows: Lat: 53.97568°, Lon: -128.69992°. Total precipitation amount (mm) and precipitation event intensity (mm/hr) in specific time intervals (5 minutes to 24 hours) for various return periods (2 years to 100 years), are provided in Tables 10 to 17. Projections for future climate IDF data are available based on results from 24 Global Circulation Models that simulate future climate conditions. The projected IDF data presented here is based on bias-corrected results from 9 downscaled climate models under the RCP 8.5 emission scenario from the Pacific Climate Impacts Consortium. These IDF projections are published by the Institute for Catastrophic Loss Reduction (ICLR) at Western University, London, Ontario.

Table 10 Historical Precipitation Event Accumulation IDF data (mm) – Kitimat (Lat: 53.97568°, Lon: -128.69992°)

T (years)	2	5	10	25	50	100
5 min	2.16	3	3.69	4.73	5.66	6.74
10 min	3.22	4.37	5.38	7.03	8.58	9.38
15 min	4.43	5.81	6.69	7.78	8.58	9.38
30 min	6.54	7.91	9.08	10.94	12.67	14.77
1 h	10.18	12.66	14.53	17.19	19.41	21.84
2 h	17.22	21.39	24.57	29.15	33.01	37.28
6 h	39.83	51.81	60.46	72.32	81.86	92
12 h	61.71	79.17	92.08	110.2	125.1	141.28
24 h	89.35	115.27	131.34	150.44	163.77	176.32

Table 11 Projected Precipitation Event Accumulation IDF data (mm) and Percent Change from Historical (%), Kitimat (Lat: 53.97568°, Lon: -128.69992°), RCP 8.5, 2020s (2015-2044)

T (years)	2		5		10		25		50		100	
	Total (mm)	% Change	Total (mm)	% Change	Total (mm)	% Change	Total (mm)	% Change	Total (mm)	% Change	Total (mm)	% Change
5 min	2.23	3.2%	3.11	3.7%	3.82	3.5%	5.01	5.9%	5.97	5.5%	7.1	5.3%
10 min	3.33	3.4%	4.53	3.7%	5.58	3.7%	7.44	5.8%	9.05	5.5%	9.87	5.2%
15 min	4.58	3.4%	6.01	3.4%	6.93	3.6%	8.23	5.8%	9.05	5.5%	9.87	5.2%
30 min	6.76	3.4%	8.2	3.7%	9.41	3.6%	11.58	5.9%	13.36	5.4%	15.55	5.3%
1 h	10.52	3.3%	13.11	3.6%	15.06	3.6%	18.2	5.9%	20.47	5.5%	23	5.3%
2 h	17.8	3.4%	22.16	3.6%	25.47	3.7%	30.86	5.9%	34.81	5.5%	39.25	5.3%
6 h	41.18	3.4%	53.67	3.6%	62.68	3.7%	76.55	5.8%	86.3	5.4%	96.86	5.3%
12 h	63.81	3.4%	82.02	3.6%	95.47	3.7%	116.65	5.9%	131.9	5.4%	148.74	5.3%
24 h	92.38	3.4%	119.42	3.6%	136.18	3.7%	159.25	5.9%	172.67	5.4%	185.64	5.3%

Table 12 Projected Precipitation Event Accumulation IDF data (mm) and Percent Change from Historical, Kitimat (Lat: 53.97568°, Lon: -128.69992°), RCP 8.5, 2050s (2041-2070)

T (years)	2		5		10		25		50		100	
	Total (mm)	% Change	Total (mm)	% Change	Total (mm)	% Change	Total (mm)	% Change	Total (mm)	% Change	Total (mm)	% Change
5 min	2.35	8.8%	3.27	9.0%	4.12	11.7%	5.29	11.8%	6.09	7.6%	7.14	5.9%
10 min	3.51	9.0%	4.75	8.7%	6.01	11.7%	7.85	11.7%	9.23	7.6%	9.93	5.9%
15 min	4.84	9.3%	6.32	8.8%	7.48	11.8%	8.68	11.6%	9.23	7.6%	9.93	5.9%
30 min	7.14	9.2%	8.61	8.8%	10.15	11.8%	12.22	11.7%	13.64	7.7%	15.65	6.0%
1 h	11.11	9.1%	13.77	8.8%	16.24	11.8%	19.2	11.7%	20.89	7.6%	23.14	6.0%
2 h	18.8	9.2%	23.28	8.8%	27.47	11.8%	32.55	11.7%	35.53	7.6%	39.5	6.0%
6 h	43.5	9.2%	56.38	8.8%	67.6	11.8%	80.75	11.7%	88.09	7.6%	97.46	5.9%
12 h	67.4	9.2%	86.17	8.8%	102.96	11.8%	123.05	11.7%	134.63	7.6%	149.67	5.9%
24 h	97.58	9.2%	125.46	8.8%	146.86	11.8%	167.99	11.7%	176.25	7.6%	186.8	5.9%

Table 13 Projected Precipitation Event Accumulation IDF data (mm) and Percent Change from Historical, Kitimat (Lat: 53.97568°, Lon: -128.69992°), RCP 8.5, 2080s (2071-2100)

T (years)	2		5		10		25		50		100	
	Total (mm)	% Change	Total (mm)	% Change	Total (mm)	% Change	Total (mm)	% Change	Total (mm)	% Change	Total (mm)	% Change
5 min	2.6	20.4%	3.64	21.3%	4.49	21.7%	5.69	20.3%	6.81	20.3%	8.13	20.6%
10 min	3.88	20.5%	5.3	21.3%	6.55	21.7%	8.45	20.2%	10.31	20.2%	11.31	20.6%
15 min	5.35	20.8%	7.04	21.2%	8.14	21.7%	9.34	20.1%	10.31	20.2%	11.31	20.6%
30 min	7.89	20.6%	9.59	21.2%	11.06	21.8%	13.14	20.1%	15.23	20.2%	17.82	20.6%
1 h	12.28	20.6%	15.34	21.2%	17.69	21.7%	20.65	20.1%	23.33	20.2%	26.35	20.7%
2 h	20.78	20.7%	25.92	21.2%	29.92	21.8%	35.02	20.1%	39.68	20.2%	44.97	20.6%
6 h	48.07	20.7%	62.8	21.2%	73.63	21.8%	86.87	20.1%	98.38	20.2%	110.98	20.6%
12 h	74.47	20.7%	95.97	21.2%	112.15	21.8%	132.38	20.1%	150.36	20.2%	170.42	20.6%
24 h	107.83	20.7%	139.73	21.2%	159.96	21.8%	180.72	20.1%	196.84	20.2%	212.69	20.6%

The results indicate that an increase in precipitation accumulation can be expected at the asset location for most of the precipitation events. Under RCP 8.5, the projected percentage change from the 1981-2010 data for precipitation events range from 3.2% to 5.9% for the 2020s (2011-2040), 5.9% to 11.8% for the 2050s (2041-2070), and 20.1% to 21.8% for the 2080s (2071-2100).

The increase in precipitation for accumulation shown above correlates to increased precipitation event intensity (mm/hr) as shown below for the ungauged location.

Table 14 Historical Precipitation Event Intensity IDF data (mm/hr) – Kitimat (Lat: 53.97568°, Lon: -128.69992°)

T (years)	2	5	10	25	50	100
5 min	25.86	36.03	44.27	56.81	67.95	80.89
10 min	19.3	26.21	32.27	42.2	34.32	37.5
15 min	17.72	23.22	26.75	31.11	34.32	37.5
30 min	13.07	15.83	18.16	21.88	25.35	29.54
1 h	10.18	12.66	14.53	17.19	19.41	21.84
2 h	8.61	10.69	12.29	14.58	16.51	18.64
6 h	6.64	8.63	10.08	12.05	13.64	15.33
12 h	5.14	6.6	7.67	9.18	10.42	11.77
24 h	3.72	4.8	5.47	6.27	6.82	7.35

Table 15 Projected Precipitation Event Intensity IDF data (mm/hr) and Percent Change from Historical (%), Kitimat (Lat: 53.97568°, Lon: -128.69992°), RCP 8.5, 2020s (2015-2044)

T (years)	2		5		10		25		50		100	
	Intensity (mm/hr)	% Change	Intensity (mm/hr)	% Change	Intensity (mm/hr)	% Change	Intensity (mm/hr)	% Change	Intensity (mm/hr)	% Change	Intensity (mm/hr)	% Change
5 min	26.74	3.4%	37.32	3.6%	45.89	3.7%	60.13	5.8%	71.65	5.4%	85.17	5.3%
10 min	19.96	3.4%	27.15	3.6%	33.46	3.7%	44.67	5.9%	54.27	58.1%	59.23	57.9%
15 min	18.33	3.4%	24.06	3.6%	27.73	3.7%	32.93	5.9%	36.18	5.4%	39.48	5.3%
30 min	13.51	3.4%	16.39	3.5%	18.83	3.7%	23.16	5.9%	26.73	5.4%	31.1	5.3%
1 h	10.52	3.3%	13.11	3.6%	15.06	3.6%	18.2	5.9%	20.47	5.5%	23	5.3%
2 h	8.9	3.4%	11.08	3.6%	12.74	3.7%	15.43	5.8%	17.4	5.4%	19.63	5.3%
6 h	6.86	3.3%	8.95	3.7%	10.45	3.7%	12.76	5.9%	14.38	5.4%	16.14	5.3%
12 h	5.32	3.5%	6.84	3.6%	7.96	3.8%	9.72	5.9%	10.99	5.5%	12.39	5.3%
24 h	3.85	3.5%	4.98	3.8%	5.67	3.7%	6.64	5.9%	7.19	5.4%	7.73	5.2%

Table 16 Projected Precipitation Event Intensity IDF data (mm/hr) and Percent Change from Historical, Kitimat (Lat: 53.97568°, Lon: -128.69992°), RCP 8.5, 2050s (2041-2070)

T (years)	2		5		10		25		50		100	
	Intensity (mm/hr)	% Change	Intensity (mm/hr)	% Change	Intensity (mm/hr)	% Change	Intensity (mm/hr)	% Change	Intensity (mm/hr)	% Change	Intensity (mm/hr)	% Change
5 min	28.24	9.2%	39.21	8.8%	49.5	11.8%	63.43	11.7%	73.13	7.6%	85.7	5.9%
10 min	21.08	9.2%	28.53	8.9%	36.08	11.8%	47.12	11.7%	55.4	61.4%	59.6	58.9%
15 min	19.36	9.3%	25.27	8.8%	29.91	11.8%	34.74	11.7%	36.93	7.6%	39.73	5.9%
30 min	14.28	9.3%	17.22	8.8%	20.3	11.8%	24.43	11.7%	27.28	7.6%	31.29	5.9%
1 h	11.11	9.1%	13.77	8.8%	16.24	11.8%	19.2	11.7%	20.89	7.6%	23.14	6.0%
2 h	9.4	9.2%	11.64	8.9%	13.74	11.8%	16.28	11.7%	17.76	7.6%	19.75	6.0%
6 h	7.25	9.2%	9.4	8.9%	11.27	11.8%	13.46	11.7%	14.68	7.6%	16.24	5.9%
12 h	5.62	9.3%	7.18	8.8%	8.58	11.9%	10.25	11.7%	11.22	7.7%	12.47	5.9%
24 h	4.07	9.4%	5.23	9.0%	6.12	11.9%	7	11.6%	7.34	7.6%	7.78	5.9%

Table 17 Projected Precipitation Event Intensity IDF data (mm/hr) and Percent Change from Historical, Kitimat (Lat: 53.97568°, Lon: -128.69992°), RCP 8.5, 2080s (2071-2100)

T (years)	2		5		10		25		50		100	
	Intensity (mm/hr)	% Change	Intensity (mm/hr)	% Change	Intensity (mm/hr)	% Change	Intensity (mm/hr)	% Change	Intensity (mm/hr)	% Change	Intensity (mm/hr)	% Change
5 min	31.21	20.7%	43.67	21.2%	53.91	21.8%	68.24	20.1%	81.68	20.2%	97.58	20.6%
10 min	23.29	20.7%	31.77	21.2%	39.3	21.8%	50.69	20.1%	61.87	80.3%	67.86	81.0%
15 min	21.39	20.7%	28.15	21.2%	32.57	21.8%	37.37	20.1%	41.24	20.2%	45.24	20.6%
30 min	15.77	20.7%	19.18	21.2%	22.11	21.8%	26.28	20.1%	30.47	20.2%	35.63	20.6%
1 h	12.28	20.6%	15.34	21.2%	17.69	21.7%	20.65	20.1%	23.33	20.2%	26.35	20.7%
2 h	10.39	20.7%	12.96	21.2%	14.96	21.7%	17.51	20.1%	19.84	20.2%	22.49	20.7%
6 h	8.01	20.6%	10.47	21.3%	12.27	21.7%	14.48	20.2%	16.4	20.2%	18.5	20.7%
12 h	6.21	20.8%	8	21.2%	9.35	21.9%	11.03	20.2%	12.53	20.2%	14.2	20.6%
24 h	4.49	20.7%	5.82	21.3%	6.67	21.9%	7.53	20.1%	8.2	20.2%	8.86	20.5%

The results indicate that an increase in precipitation intensity can be expected in the region of Kitimat for most of the durations presented above. Under RCP 8.5, the projected percentage change from the 1981-2010 data for precipitation events range from 3.3% to 58.1% for the 2020s (2011-2040), 5.9% to 61.4% for the 2050s (2041-2070), and 20.1% to 81.0% for the 2080s (2071-2100).

3.4 1,3,5 DAY ACCUMULATION

Observations from three ECCC weather stations: Kitimat 2 (Station Id: 1064321), Kitimat Hatchery (Station Id: 1064289) and Kitimat Townsite (Station Id: 1064320) were merged to obtain the complete datasets of precipitation for the years from 1970 to 2020 at the region of Kitimat. Record 1, 3, 5-day precipitation accumulations in Kitimat region are shown in Table 18 for the highest recorded observations at the three ECCC weather stations for the complete datasets from 1970 to 2020. Historical and projected estimates for maximum 1, 3, and 5-day precipitation accumulation in Kitimat region are shown in Table 19. The precipitation accumulation for 1, 3 and 5- day events is projected to increase under RCP 8.5 scenario in Kitimat region.

Table 18 Historical Precipitation Event Accumulation (mm) – region of Kitimat

	Record Maximum Precipitation Accumulation Region of Kitimat (1970-2020)		
	1 day	**3 day**	**5 day**
Precipitation (mm)	179.4	369.4	407.0
Event Date	31-Oct-78	01-Nov-78	02-Nov-78

Table 19 Historical and Projected Average Annual Maximum 1, 3, 5 Day Precipitation Accumulations (RCP 8.5) in Kitimat Region

Duration	Average Annual Maximum Precipitation Accumulation (mm)			
	1981-2010 Baseline	**2020s**	**2050s**	**2080s**
1-Day	81	80.1	85.0	93.2
3-Day	154	117.4	124.5	135.7
5-Day	198	164.2	174.2	188.7

4.0 FROST DAYS

Frost days are days when the daily minimum temperature is less than 0°C, indicating when conditions are below freezing (typically overnight) and frost might form at ground level or on cold surfaces. Historical and projected estimates for average annual number of frost days for Kitimat region are shown in Table 20. The frequency of occurrence of frost days is projected to decrease under RCP 8.5 scenario in the region.

Table 20 Average Annual Number of Frost Days in Kitimat Region (RCP 8.5)

Average Annual Number of Frost Days			
1981-2010 Baseline	**2020s**	**2050s**	**2080s**
89.0	69.3	46.5	30.7

5.0 ICE DAYS

Frost days are days when the daily maximum temperature is less than 0°C, indicating when conditions are favorable for snow retention. Historical and projected estimates for average annual number of icing days in Kitimat region are shown in Table 21. The frequency of occurrence of icing days is projected to decrease under RCP 8.5 scenario in the region.

Table 21 Average Annual Number of Icing Days in Kitimat Region (RCP 8.5)

Average Annual Number of Icing Days			
1981-2010 Baseline	**2020s**	**2050s**	**2080s**
25.0	24.3	18.0	12.0

6.0 FREEZE-THAWS

Freeze-thaw cycles are days (24-hr periods) when the air temperature fluctuates between freezing and non-freezing temperatures. A freeze-thaw cycles is therefore a day with the maximum temperature greater than 0°C and the minimum temperature equal to or less than -1°C. A minimum temperature threshold of -1°C (instead of 0°C) is used to increase the likelihood that water present at the surface actually freezes. The historic and projected annual number of freeze-thaw cycles in the Kitimat region are presented in Table 22. The annual number of freeze-thaw cycles is projected to decrease under future climate conditions in the region.

Table 22 Historical and Projected Annual Freeze-Thaw Cycles (Day with Maximum Temperature > 0°C & Minimum Temperature ≤ -1°C) in Kitimat Region

Average Annual Free-Thaw Cycles (1981-2010)	Projected Change in Freeze-Thaw Days		
	2020s	2050s	2080s
30.2	46.4	30.1	19.7

7.0 HEAT WAVES

For this climate profile, a heat wave is defined as three or more consecutive days with a daily maximum temperature of 30°C or greater. The frequency of heat waves (Table 23) and average annual length of heat waves (Table 24) are projected to increase for Kitimat region.

Table 23 Average Annual Number of Heat Waves for Kitimat Region (RCP 8.5)

Average Annual Number of Heat Waves			
1981-2010 Baseline	**2020s**	**2050s**	**2080s**
0.7	0.0	0.1	1.0

Table 24 Average Annual Length of Heat Waves for Kitimat Region (RCP 8.5)

Average Annual Length of Heat Waves (Days)			
1981-2010 Baseline	**2020s**	**2050s**	**2080s**
0.4	0.9	1.9	3.4

8.0 HEATING DEGREE DAYS

Heating Degree Days (HDD) are equal to the number of degrees Celsius the daily mean temperature is below 18°C. For example, if the daily mean temperature is 15°C, 3°C HDD are accrued. HDD are accumulated over a time period (e.g., monthly, seasonally, or annually). HDD provide an indication of the heating capacity required to maintain comfortable building conditions during cooler months. The historic and projected HDD values provided below demonstrates a decrease in heating needs under future climate conditions in Kitimat region (Table 25).

Table 25 Average Annual Heating Degree Days for Kitimat Region (RCP 8.5)

Average Annual Heating Degree Days (°C)			
1981-2010 Baseline	**2020s**	**2050s**	**2080s**
4207.0	3656.3	3130.3	2642.4

9.0 COOLING DEGREE DAYS

Cooling Degree Days (CDD) are equal to the number of degrees Celsius the daily mean temperature is above 18°C. For example, if the daily mean temperature is 20°C, 2°C CDD are accrued. CDD are accumulated over a time period (e.g., monthly, seasonally, or annually). CDD provide an indication of the cooling capacity required to maintain comfortable building conditions during warmer months. The historic and projected CDD values provided below demonstrates an increase in cooling needs under future climate conditions in the Kitimat region (Table 26).

Table 26 Average Annual Cooling Degree Days for Kitimat Region (RCP 8.5)

Average Annual Cooling Degree Days (°C)			
1981-2010 Baseline	**2020s**	**2050s**	**2080s**
51.0	86.1	172.5	313.4

10.0 WIND

The Terrace A weather station (ID:1068134) has hourly and daily wind data available during the 1971-2020 time period. The recorded daily wind gusts data show approximately 39.4% data with wind gusts of <31 km/h. The available wind data is used to generate windroses for the climate profile of Kitimat region. Windroses show the distribution of wind direction (direct from which the wind is blowing) observed at a particular location over a time period. The length of each line represents the frequency of the wind from that direction and, therefore, windroses provide information on the prevailing wind direction(s) at a given location. Figure 14 displays hourly mean wind speed and direction observed from 2010-2020 at the Terrace A weather station (ID: 1068134) while Figure 15 displays the daily maximum wind gust speed and direction observed from 1971-2020.

Figure 13 Hourly mean wind speed and direction from 1971-2020 observed at Terrace A weather station (ID: 1068134)

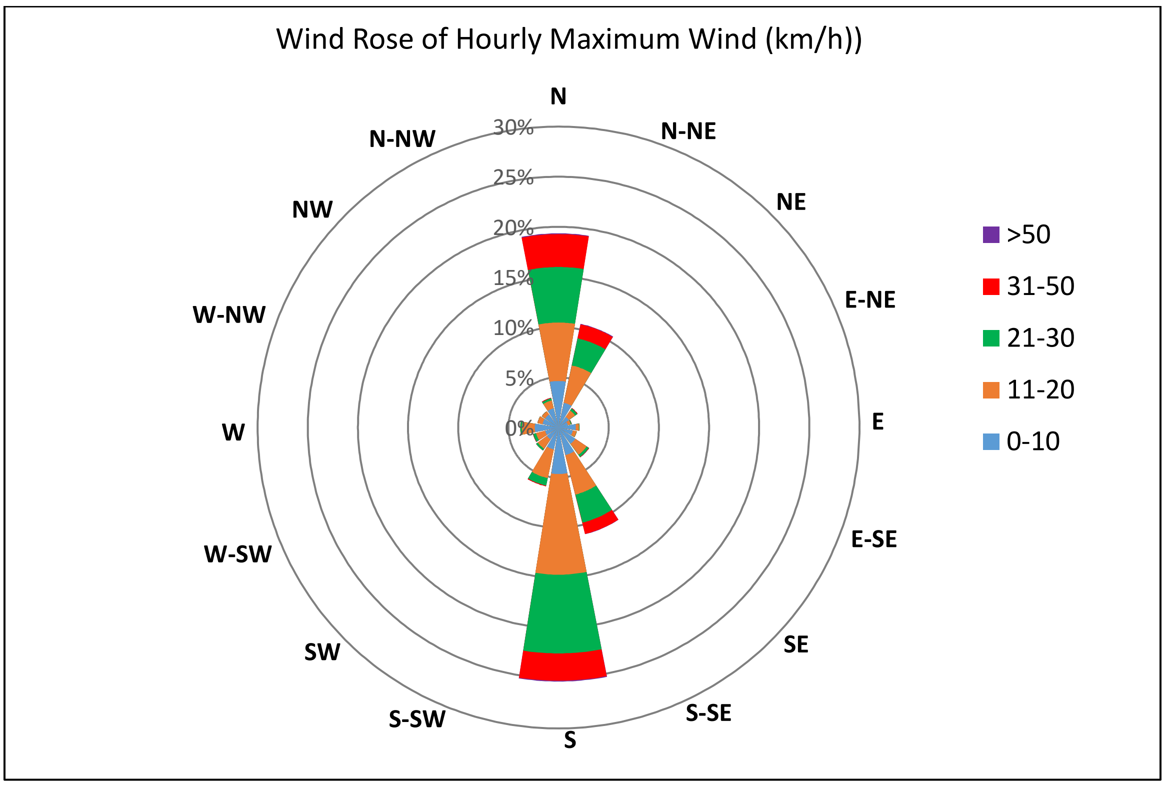
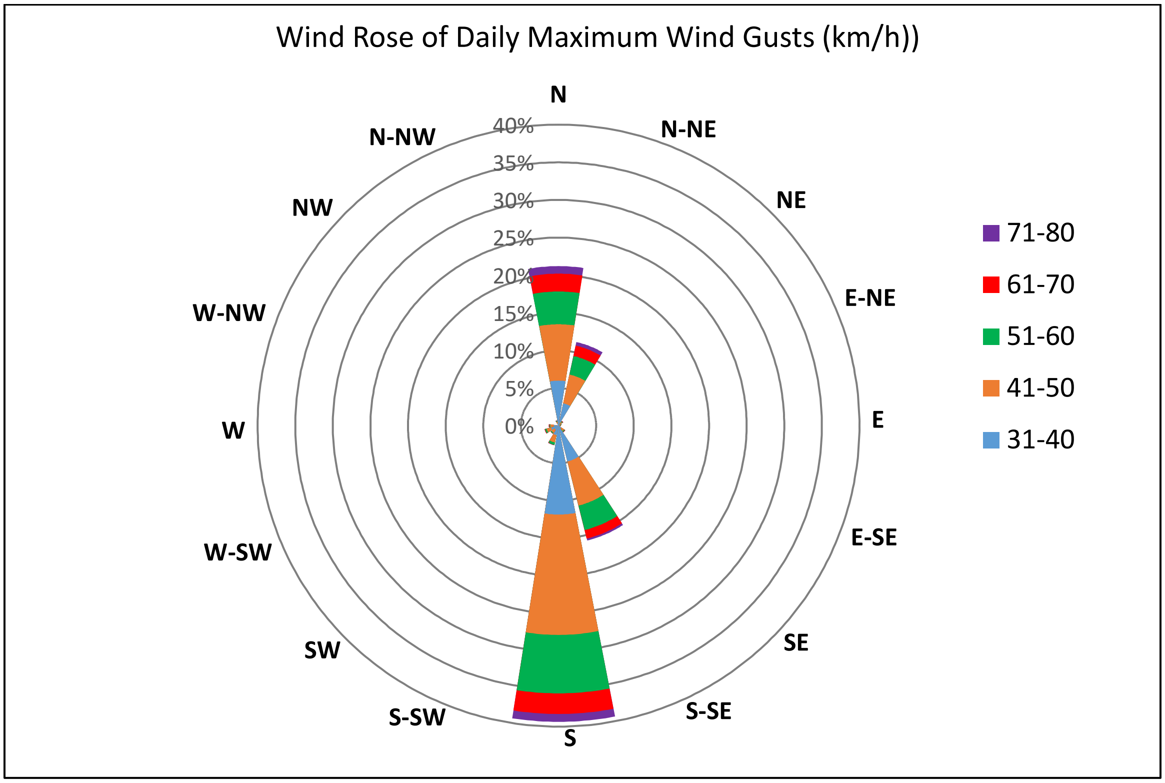


Figure 14 Daily maximum wind gust speed and direction from 1971-2020 observed at the Terrace A weather station (ID: 1068134)



The projected climate changes with respect to wind are not as well understood as variables such as temperature. The analyses of 57 years (1953–2009) historical record of wind gusts at 104 weather stations across Canada show that for every 1°C increase in the daily temperature anomaly, the speed of daily wind gust events (≥50 km/h) increases by more than 0.2 km/h over most regions in Canada (Cheng C. , 2014). The percentage increases in future daily wind gust events of ≥70 km/h from the current condition could be 10%–20% in most of the regions across Canada (Cheng C. L., 2014).

Table 27 Historical Annual Wind Gust Events in the Kitimat Region for the 1971-2020 Period

Extreme Wind Gust Events	Days/year
≥ 90km/h	0.84
≥ 120km/h	0.04

11.0 WILDFIRES

On average from 1970-2017, 8000 wildfires occurred across Canada annually (Canadian Forest Service 2017). However, few are deemed as a disaster and the majority are managed and result in no or few negative impacts. Thus, for this assessment, the hazard threshold is determined to be occurrence of large fire (≥ 200 ha) within 100km of Kitimat. However, it is important to note that severe wildfire outside the 100km radius can still affect the visibility and air quality of Kitimat. Using the Canadian Wildland Fire Information System (CWFIS) (NRCan, 2017), at least 19 separate large wildfires for the 1950- 2020 period were observed within a 100 km radius of Kitimat.

Under the RCP8.5 climate change projections, the area burnt by wildfires are expected to increase gradually from 2020 to 2050 and exponentially from 2050 to 2100 (Balshi, 2008.). Due to the predicted warmer temperatures, change in precipitation and intensification of drought events, fire occurrences are expected to increase by 10-25% by 2090 in the Kitimat region (Flannigan, 2009) (Wotton, 2010), using the Canadian Climate Center GCM. Additionally, temperature has also shown a strong positive correlation with lightning, humidity and fire season. Therefore, warmer temperature may result in longer fire season, more frequent and intense wildfires. However, this conclusion is subjected to a moderate amount of uncertainty due to the complex nature of wildfires, its fuel type and possible future fire management adaptation plans.

12.0 SEA LEVEL CHANGE

Sea levels are projected to rise as a result of the thermal expansion of water as an impact of atmospheric and sea temperature warming. There is a large amount of uncertainty associated with the sensitivity of the Antarctic and Arctic ice sheets and glaciers to warming which could add a considerable volume of water to the world's oceans if accelerated melting takes place.

Natural Resources Canada (NRC) reports on sea level change scenarios for relative sea-level projections for 59 locations in Canada up to the year 2100. For Kitimat, the average projected sea level changes are 60-65 cm (rise) for the period of 2081-2100 relative to 1986-2005 sea level based on projections of the IPCC AR5, RCP 8.5 (T.S James, 2021). Considering global sea-level rise from West Antarctica due to Antarctic ice-sheet reduction, the relative sea level changes at Kitimat are projected to be 120-130 cm (rise) in 2100 (T.S James, 2021).

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