Stantec

Technical Data Report—Strategic Assessment of Climate Change

Ksi Lisims LNG – Natural Gas Liquefaction and Marine Terminal Project

August 2024

Prepared jointly by:

KSI LISIMS LNG

and

Stantec Consulting Ltd.

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Table of Contents

LIST OF TABLES

LIST OF FIGURES

Executive Summary

The Nisg̱a'a Nation, Rockies LNG Limited Partnership (**Rockies LNG**) and Western LNG LLC (via its subsidiary, Western LNG) (each a Proponent and collectively referred to herein as **the Proponents**), are proposing to jointly develop an energy project, the Ksi Lisims LNG – Natural Gas Liquefaction and Marine Terminal Project (**the Project**). The Project is a floating liquefied natural gas (**FLNG**) production, storage and offloading facility, with supporting upland infrastructure and marine terminal. The Project Site is located at Wil Milit, on the northern end of Pearse Island, approximately 15 kilometres (**km**) west of the Nisg̱a'a community of Gingolx. The Site is on Category A fee simple land as defined in the Nisg̱a'a Final Agreement (**Nisg̱a'a Treaty**) and is adjacent to a proposed water lot located on the east side of the Site, in Portland Canal.

This technical data report presents detailed technical data and analysis to support the Strategic Assessment of Climate Change (**SACC**) as per the guidance from Environment and Climate Change Canada (**ECCC**).

The Project's estimated carbon sink impact (**CSI**) was determined by estimating the existing natural flux within the Project footprint and conservatively assuming that, post-Project, the natural flux is zero. The natural flux in a forest is the annual carbon accumulation rate that exists due to the growth of trees. For a wetland, the natural flux is the annual carbon accumulation rate due to the decomposition and storage of biomass. Over time, carbon is stored in the soil.

Tree species present within the 43.6 hectare (**ha**) Project area (defined as Forest Land as per SACC guidance) are western redcedar (9.75 ha), western hemlock (10.1 ha), yellow cedar (4.40 ha), and spruce (0.68 ha) (British Columbia Ministry of Forests, Lands, Natural Resource Operations and Rural Development 2021). The age of the trees ranged from 318 to 349 years old. Approximately 10.4 ha of the Project footprint is bog wetland, based on the findings of the Vegetation and Wetland Technical Data Report (**TDR**, Appendix 7.06A of the Application).

The total CSI for the Project is 218 tonnes (**t**) of carbon (**C**), including no carbon from Forest Land and 218 t of carbon from Wetlands. This results in approximately 218 t of carbon that may not be removed from the atmosphere due to the Project. For context, if this amount of carbon was burned, it would generate approximately 800 t of carbon dioxide (**CO_2**), which is approximately how much 245 passenger cars would release in one year of driving (NRCan nd).

Upstream greenhouse gas (**GHG**) emissions are those that occur from the production, processing, and transmission of the natural gas prior to use by the Project but are outside the scope of the Project. A screening assessment for upstream emissions indicated that the Project's upstream GHG emissions are potentially over 500 kilotonnes (**kt**) carbon dioxide equivalent (**CO_2e**). Using the upstream GHG methodology presented in the SACC and the associated draft Technical Guide Related to the Strategic Assessment of Climate Change (the **draft Technical Guide**, ECCC 2021), the total annual emissions range between 3,245 kt to 4,141 kt CO_2e per year. This corresponds with an upstream GHG emission intensity of approximately 0.27 t CO_2e/t LNG after 2034. These upstream emissions are potentially incremental to existing natural gas production, processing, and transmission GHG emissions in Canada, but are not considered incremental on a North American and broader global export scale. The Project, supplied with Western Canadian Sedimentary Basin (**WCSB**) natural gas, has lower well-to-port emissions intensities (see Figure 4.6–1) than comparable projects on the United States (**US**) Gulf Coast with intensities between 0.76–1.19 tonnes of GHG/tonne of LNG. At full scale, the Project will produce 9–14 million tonnes less CO_2e per year than a comparable US Gulf Coast facility.

Natural gas is projected to remain a critical supply of primary energy to meet the growing needs of consumers globally (Shell 2023, Woodmac 2022, Platts 2023, BP 2023). Demand for natural gas, particularly in Asia, is expected to continue growing (Shell 2023). Global LNG prices hit record high levels in Q4 2021 and demand is expected to nearly double in the next twenty years (Shell 2021, Woodmac 2022). According to the Gas Exporting Countries Forum, global natural gas demand is projected to increase 36% by 2050 with LNG demand more than doubling between 2021 and 2050 (GECF 2022).

Growing demand for LNG, coupled with supply loss as older LNG production facilities are retired from service, necessitates continued investment in LNG production facilities around the world. Even under the most optimistic net-zero scenarios, continued investment in low-carbon LNG production is required. Without lower-carbon Canadian LNG supply, there is potential for an increasing risk of carbon leakage if the Project (and other lower-carbon LNG projects) is not built in Canada.

The Project is expected to be one of the lowest GHG emissions-intensive sources of LNG globally. This advantage is the result of three factors: (i) lower lifecycle emissions intensity natural gas production, which is the result of a continued focus by government and industry in Canada to lower its greenhouse gas emissions; (ii) access to renewable hydropower for the facility, which is advantageous over other sources of renewable energy due to hydro’s inherent storage component that eliminates supply intermittency; and (iii) considerably shorter shipping distances between the Project Site and Asian markets than other potential sources of marginal LNG supply, principally on the US Gulf Coast. Exporting Canadian LNG also supports global energy security and could provide global environmental benefits as the risk of carbon leakage of continued LNG exports from more carbon intensive countries is high. Lower GHG emissions intensity Canadian LNG can replace fuels with higher GHG emissions intensities, such as oil and coal.

The Best Available Technology and Best Environmental Practices (**BAT**/**BEP**) Determination considered the following areas related to the Project:

- Construction and decommissioning: carbon sinks, on-land equipment, marine equipment
- Operations: primary energy source, back-up energy source, waste gas containing CO_2, fugitive emissions, disposal of natural gas during maintenance, upset, or emergencies, LNG carriers in transit, LNG carriers at terminal, tugboats in transit, tugboats at terminal

For each technology and practice identified, a technical feasibility assessment was conducted. Those technologies and practices identified as technically feasible were carried forward for a GHG reduction potential assessment and a financial feasibility assessment. Two BAT/BEP combinations were identified (one realistic and one optimistic in terms of technology availability); the realistic BAT/BEP combination was selected to represent the BAT/BEP for the Project. A summary of the selected combination can be found in Table 5.6–3. The key BAT selection is the connection to the BC electricity grid, which will result in a reduction in GHG emissions over a combined cycle gas turbine power plant of approximately 98% (2,279,785 t CO_2e per tear).

The Proponent’s net-zero plan takes an ‘already best-in-class' Project and confirms the Proponents commitments to climate change action. The net-zero plan prioritizes avoidance of emissions based on Project design. For remaining emissions, the net-zero plan includes a commitment to continuous evaluation and assessment of further emission reductions (enabled through development of new technologies) and the offsetting of residual emissions aligned with the Project’s offset framework. Overall, the net-zero plan results in a facility design that has a best-in-class GHG emissions intensity compared to other LNG projects globally and is net-zero ready for 2030.

A key requirement under the base case for the Project to achieve net-zero by 2030 is for BC Hydro to be in a position to deliver grid supplied power to the point of interconnection (**POI**) with the Project by 2030. Major recent announcements by the BC government indicate that both sufficient power and an accelerated timeline for transmission upgrades in the region will occur. In the event BC Hydro is not able to supply the Project with power at the start of operations, the Proponents are proposing the time-limited use of gas-fired power barges. In the event of this alternate scenario, the Proponents are committed to working with rightsholders, stakeholders, and the government to find viable solutions that ensure alignment with the objectives of the British Columbia New Energy Action Framework, until such time as BC Hydro has completed the grid interconnection for the Project. There is no intention to continue using on-Site gas-fired generation capacity following the date that full grid connection for the Project is completed.

The Proponents have initiated conversations with the Nisg̲a'a Nation on the development of offset opportunities focused initially on nature-based solutions within the Nation’s Treaty Territory. Furthermore, there are substantive opportunities to establish other offset projects within the broader project region, and the Proponent intends to explore such options and conduct similar investigatory studies with participating Indigenous nations. Preliminary work by both the Project and the First Nations Climate Initiative (FNCI 2021) has identified potential GHG offset credit generation opportunities including forest restoration, rehabilitation, deferred harvest, and implementation of enhanced ecosystem-based management. GHG offset credits generated from Indigenous-owned offset projects could be used to offset some or potentially all the emissions generated by the Project. Offset projects would have other benefits, including increased forest growth, enhanced ecology and biodiversity, and in the case of Nisg̲a'a Nation, a restoration of a portion of the degraded Nass Bottomlands.

The Proponents will work with indigenous nations to explore other emission mitigation and avoidance offset development opportunities on their lands and potentially surrounding marine environments.

More broadly, across the full domestic value chain, the Proponents are committed to working with other Indigenous nations and interested parties that may have offset projects for consideration.

A Climate Change Resilience Assessment (**CCRA**) has been conducted to assess risks to the Project due to climate change and to identify adaptation options to 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 alert the Project management team to projected changes in climate and associated risks to consider at the Project's detailed design stage, and to highlight climate change impacts on operations throughout the life of the Project.

The climate hazards used for this resilience assessment were chosen based on experience with previous climate change resilience studies for similar types of project 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 increased maintenance requirements of infrastructure components and increased discomfort for personnel.
- Freeze-thaw cycles, which can increase maintenance requirements for walkways, roadways, and can increase slip and fall risks for personnel.
- Short duration high intensity rainfall, which can cause local flooding, can lead to structural damage of infrastructure components, and can result in increased maintenance requirements.
- Heavy snowfall, which can impact the surface conditions of decks, platforms, roadways, can result in increased maintenance costs for snow clearing and can increase slip and fall risks for personnel.
- Extreme winds, which can lead to structural damage to the Project or reduce facility operations or impede Site access.
- Sea level rise, which can lead to flooding of infrastructure assets.
- Lightning (as a proxy of wildfire), which can lead to structural damage, reduce facility operations, or impede Site access.

The Project components assessed included the FLNGs, jetties, cooling water systems, electrical/distribution system, feed gas piping, water and wastewater management facilities, Site access infrastructure, buildings, and third-party utility connections.

The climate variables that presented the highest risks to the Project are heating degree days, cold days, freeze-thaw cycles, long duration rainfall, heavy snowfall, and high wind events. The highest climate risks identified for the Project are summarized below.

- Heating degree days resulted in "high" risks to the building heating system under current climate and declining to "moderate" risks in the 2050s due to decreasing trend in cold temperature.
- Cold days resulted in "high" risks to the stormwater drainage system declining to "low" risks in the 2050s due to a decreasing trend in cold temperature.

- Freeze-thaw cycles may cause safety issues (slip and fall) for personnel resulting in “high” risks under current climate declining to “moderate” risks in the 2050s due to a decreasing trend in freeze-thaw cycles.
- High intensity rainfall may cause roof gutter systems to overflow and cause localized flooding. The risks for the building roof due to high intensity rainfall change from “moderate” under current climate to “high” in the 2050s.
- Heavy snowfall may cause increased snow clearing requirements and resulted in “moderate” risks under current climate and in the 2050s for access roads, helipad, and power supply. Heavy snowfall could cause safety issues (slip and fall) for personnel and resulted in “moderate” risks under current climate and in the 2050s.
- High wind gusts (wind gust events of 90 kilometres per hour (**km/h**) or more) may cause structural damage to mooring equipment, buildings, and the telecommunication tower resulting in “high” risk under current climate and in the 2050s. High wind speeds may cause safety issues for personnel resulting in “high” risks in the 2050s.
- High wind gusts (wind gust events of 90 km/h or more) may impact helicopter landing and taking off resulting in “high” risks under current climate and in the 2050s.
- High wind gusts may cause power failures and increased requirement for emergency power resulting in “high” risk under current climate and in the 2050s.

It is important to note that the climate change impacts risk profile is a prioritization of impacts relative to each other, not against an external benchmark. Designations of “high” and “moderate” risks should be considered in the context that many risks can be addressed by considering climate adjusted design criteria for future climate conditions and by adjusting operation and maintenance (**O&M**) policies and procedures as needed.

1 Abbreviations

ACG	Alberta Carbon Grid
ACTL	Alberta Carbon Trunk Line
AER	Alberta Energy Regulator
APS	Announced Pledges Scenario
BAT	best available technology
bbl eq	barrel (of oil) equivalent
BC	British Columbia
BC Hydro grid	BC Hydro electricity distribution system
BEP	Best Environmental Practice
BCEAA	British Columbia *Environmental Assessment Act*
Bcf/d	billion cubic feet per day
Bcm	billion cubic metres
BCLCS	British Columbia Land Class System
BEP	best environmental practice
BOG	boil-off gas
BTU	British thermal unit
°C	degrees Celsius
C	carbon
CCRA	climate change resilience assessment
CCS	carbon capture and storage
CCUS	carbon capture, utilization, and storage
CDD	cooling degree days

CER	Canada Energy Regulator
CH_4	methane
CHP	combined heat and power
cm	centimetre
CMIP5	Fifth Coupled Model Intercomparison Project
CNG	compressed natural gas
CO_2	carbon dioxide
CO_2e	carbon dioxide equivalent
CSI	carbon sink impact
Current Scenario	Current Policies Scenario
draft Technical Guide	draft Technical Guide Related to the Strategic Assessment of Climate Change (ECCC 2021)
EA	environmental assessment
ECCC	Environment and Climate Change Canada
EF2023	Canada's Energy Futures Report 2023
ESG	environment, social, and governance
Evolving Scenario	The Evolving Policies Scenario
FLNG	Floating liquefied natural gas production, storage and offloading facility
FNCI	First Nations Climate Initiative
GCM	global climate model
GGIRCA	British Columbia *Greenhouse Gas Industrial Reporting and Control Act*
GHG	greenhouse gas
GRI	Global Reporting Initiative
GWh	gigawatt-hour

ha	hectare
hp	horsepower
HDD	heating degree days
hp	horsepower
hr	hour
IA	Impact Assessment
IEA	International Energy Agency
IMO	International Maritime Organization
IPCC	Intergovernmental Panel on Climate Change
kg	kilogram
km	kilometre
km^2	square kilometre
km/h	kilometre per hour
kt	kilotonne
kW	kilowatt
kWh	kilowatt-hour
L25	54 horsepower electric wheel loader
LDAR	leak detection and repair
LNG	liquefied natural gas
MCC	maximum carrying capacity
m	metre
m^3	cubic metre
mbbl/d	thousand barrels per day
mm	millimetre
mmBTU	million British Thermal Unit

mmBtu/bbl	million British Thermal Units per barrel
mmBTU/mcf	million British Thermal Units per thousand cubic feet
mscf	thousand cubic feet
Mt	million tonnes
MTPA	million tonnes per annum
MW	megawatt
MWh	megawatt-hour
N_2O	nitrous oxide
NETL	National Energy Technology Lab
nd	no date
NGL	natural gas liquid
NGTL	Nova Gas Transmission Line
NIR	National Inventory Report
NZE	Net Zero Emissions
NZNIIP	Net Zero New Industry Intentions Paper
O&M	operations and maintenance
RCPs	Representative Concentration Pathways
SACC	Strategic Assessment of Climate Change
SASB	Sustainability Accounting Standards Board
STEPS	The Stated Policies Scenario
t	tonne
TCFD	Task Force on Climate-Related Financial Disclosures
TDR	Technical Data Report
the Project	Ksi Lisims LNG – Natural Gas Liquefaction and Marine Terminal Project

the Site	Project site
UNEP	United Nations Environment Programme
US	United States
US EPA	United States Environmental Protection Agency
VC	valued component
VRI	Vegetation Resources Inventory
W/m^2	watts per square metre
WCI	Western Climate Initiative
WCSB	Western Canadian Sedimentary Basin
WMO	World Meteorological Organization

1

1 Glossary

Carbon dioxide equivalent (**CO_2e**)	The CO_2e emissions are obtained by multiplying the emissions of a GHG by its global warming potential for a given time horizon. CO_2e is a metric to describe the combined effect that GHGs have on the atmosphere.
Carbon leakage	The concept that GHG emissions may increase in a jurisdiction with less stringent GHG emissions legislation due to more stringent GHG emissions legislation in another jurisdiction (e.g., a factory is shut down in Canada and a new factory is built overseas).
Project Area	The area to be utilized by the Project and includes District Lot 99 and marine waters extending approximately 500 m offshore.
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.
Global warming potential	A measure of how much heat a greenhouse gas traps in the atmosphere relative to CO_2.
Greenhouse gas (GHG)	A GHG is defined as any gas in the atmosphere that absorbs and re-emits infrared radiation.
Liquefied natural gas (LNG)	Natural gas that has been cooled to approximately -162 degrees Celsius (**°C**) where the methane (**CH_4**) 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 are designed for transporting liquefied natural gas.

Natural gas	A naturally occurring hydrocarbon gas mixture consisting primarily of CH_4 plus varying amounts of ethane, propane, butanes, pentanes, higher molecular weight hydrocarbons, hydrogen sulfide, carbon dioxide, water vapor, and sometimes helium and nitrogen.
Net-zero	The concept that the emissions being emitted are offset by emission reductions elsewhere (definition applied by Strategic Assessment of Climate Change).
Scope 1 emissions	Direct GHG emissions that occur from sources that are owned or controlled by the Project (e.g., emissions from thermal oxidizer).
Scope 2 emissions	Indirect GHG emissions associated with the generation of acquired energy from sources that are not owned or controlled by the Project (e.g., emissions from BC Hydro from electricity generation).
Scope 3 emissions	Emissions that are not produced by the Project itself and are not the result of activities from assets owned or controlled by them, but by those that it's indirectly responsible for up and down its value chain. (e.g., LNG carriers).

1

1.0 INTRODUCTION

The Nisg̱a'a Nation, Rockies LNG Limited Partnership (**Rockies LNG**) and Western LNG LLC (via its subsidiary, Western LNG) (each a Proponent and collectively referred to herein as **the Proponents**), are proposing to jointly develop an energy project, the Ksi Lisims LNG – Natural Gas Liquefaction and Marine Terminal Project (**the Project**). The Project is a floating liquefied natural gas (**FLNG**) production, storage and offloading facility, with supporting upland infrastructure and marine terminal. The Project Site is located at Wil Milit, on the northern end of Pearse Island, approximately 15 kilometres (**km**) west of the Nisg̱a'a community of Gingolx. The Site is on Category A fee simple land as defined in the Nisg̱a'a Final Agreement (**Nisg̱a'a Treaty**) and is adjacent to a proposed water lot located on the east side of the Site, in Portland Canal.

The Project is subject to a federally substituted environmental assessment (**EA**) under the British Columbia *Environmental Assessment Act* (**BCEAA**). Given the location of the Project on Category A Lands owned by the Nisg̱a'a Nation the EA will also meet requirements of Chapter 10, paragraph 8 of the Nisg̱a'a Treaty. Accordingly, an EA that focuses on a suite of valued components (**VC**s) has been prepared. VCs are components of the natural and human environment that are considered by the proponent, public, Indigenous nations, scientists and other technical specialists, and government agencies involved in the assessment process, to have scientific, ecological, economic, social, cultural, archaeological, historical, or other importance.

This document provides information to satisfy the requirements of the Strategic Assessment of Climate Change (**SACC**), the associated draft Technical Guide Related to the Strategic Assessment of Climate Change (the **draft Technical Guide**, ECCC 2021), and the British Columbia New Energy Action Framework (**NEAF**). An assessment of carbon sinks is provided in Section 2.0. An overview of the Project's impacts on Canada's efforts to reduce greenhouse gas emissions is provided in Section 3.0. 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 5.0 and the net-zero plan is provided in Section 6.0. A climate change resilience assessment is provided in Section 7.0.

Site

Marine Shipping Route

Materials and Supply Shipping Route

Potential Location of Connecting Pipeline

Prince Rupert Gas Transmission

Populated Place

Highway

International Boundary

0 5 10 15 20 km

1:750,000 (at original document size of 11x17)

KSI LISIMS LNG

Notes

1. Coordinate System: NAD 1983 UTM Zone 9N
2. Data Sources: DataBC, Government of British Columbia; Natural Resources Canada, Stantec, Nisg̱a'a Nation, Rockies LNG
3. Imagery Source: Esri, Maxar, Earthstar Geographics, and the GIS User Community

Stantec

Project Location: Pearse Island, BC

Project Number 123221820

Prepared by SMOSS on 20230816

Requested by EFLORY on 20230816

Checked by SLEMAY on 20230816

Client/Project/Report

Ksi Lisims LNG

Natural Gas Liquefaction and Marine Terminal

Strategic Assessment of Climate Change

Figure No.

1-1

Title

Ksi Lisims LNG Project Location

2.0 CARBON SINKS

2.1 INTRODUCTION

A land-use change caused by the Project may affect the natural environment's ability to absorb and store carbon dioxide (**CO_2**) from the atmosphere. This occurs most noticeably when projects change existing forest land, cropland, wetland, and grassland to the developed ("settlement") land type, as defined by the Intergovernmental Panel on Climate Change (**IPCC** 2019). A part of the environment that stores carbon is referred to as a carbon sink. An example is the biomass contained in a tree that is growing in an area of land. Carbon can also be stored in soil, such that excavations can release stored carbon into the atmosphere as CO_2.

As per the draft Technical Guide (ECCC 2021), 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. Equation 5 from the draft Technical Guide was used 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 in hectares (**ha**).

2.2 SITE-SPECIFIC DATA

2.2.1 Land-use Class

The existing land within the Project footprint includes land with vegetation and wetlands. The British Columbia Land Class System (**BCLCS**) categorized the land as upland, with both sparse and open coniferous tree cover, taken from the British Columbia Vegetation Resource Index (British Columbia Ministry of Forests, Lands, Natural Resource Operations and Rural Development. 2021). Although the Vegetation Resources Inventory (**VRI**) did not indicate the presence of wetlands within the Project Area, approximately 10.4 ha of bog were identified during fieldwork that is within the Project footprint (see Vegetation and Wetlands Technical Data Report (**TDR**), Appendix 7.06A of the Application).

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 store carbon from the atmosphere.

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

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

Where BM_{MCC} is the living tree biomass at maximum carrying capacity (t C/ha), $BM_{Current}$ is the living tree biomass at the forest stand's current age (t C/ha), Age_{MCC} is the age at which MCC is reached, and $Age_{Current}$ is the current age of the forest.

Tree species present within the 43.6 hectare (**ha**) Project area (defined as Forest Land as per SACC guidance) are western redcedar (9.75 ha), western hemlock (10.1 ha), yellow cedar (4.40 ha), and spruce (0.68 ha) (British Columbia Ministry of Forests, Lands, Natural Resource Operations and Rural Development 2021). The age of the trees ranged from 318 to 349 years old. The draft Technical Guide did not provide the MCC of western redcedar, western hemlock, yellow cedar, or spruce in the Pacific Maritime region of British Columbia.

Age and biomass information was obtained from the BCLCS (British Columbia Ministry of Forests, Lands, Natural Resource Operations and Rural Development 2021). The BCLCS has biomass information on the stem, foliage, bark, and branch; the biomass and age information from the BCLCS was used 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 2.2–1.

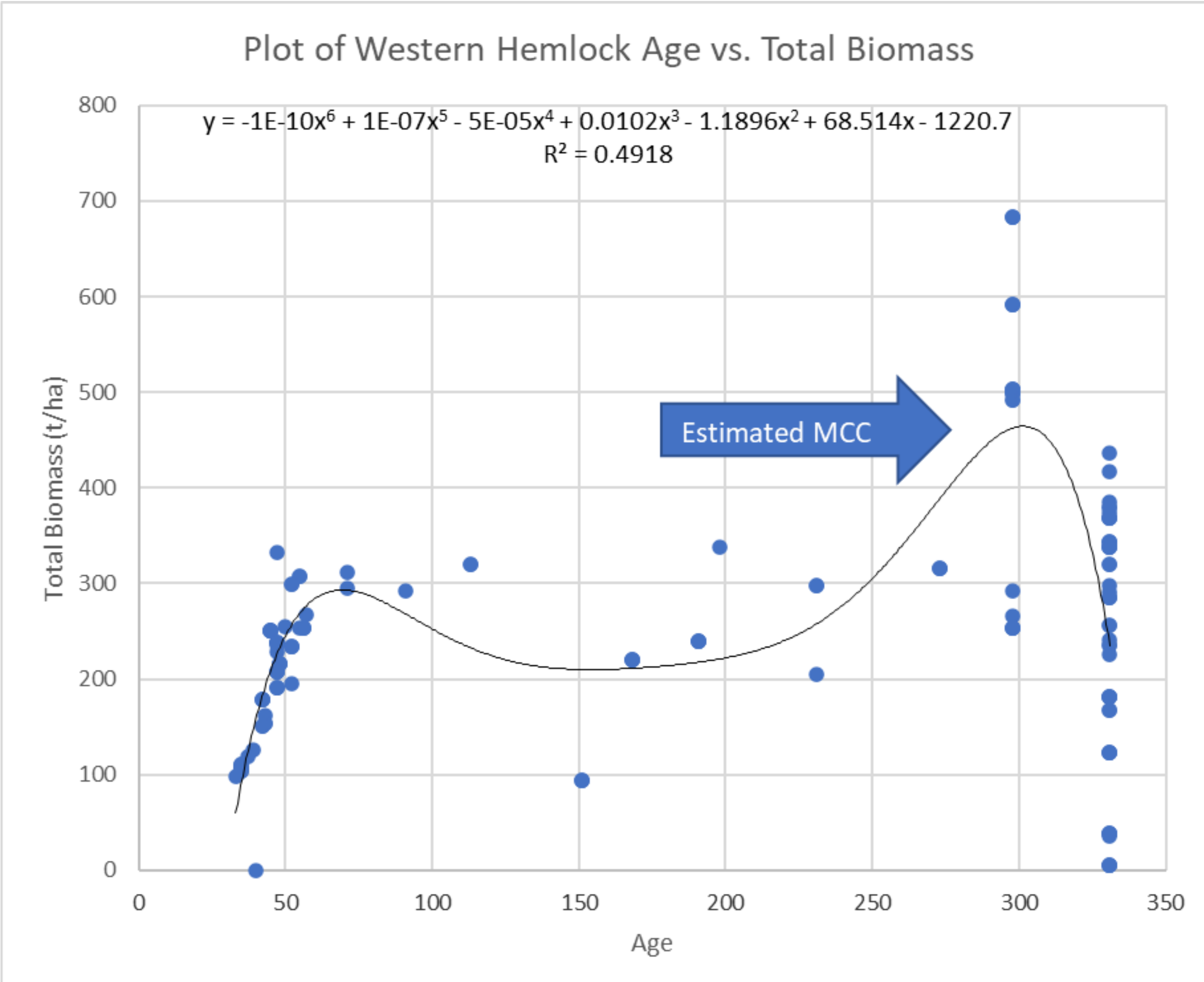

Figure 2.2–1 Plot of Western Hemlock Age vs. Total Biomass

Based on this analysis of 154 records from BCLCS (British Columbia Ministry of Forests, Lands, Natural Resource Operations and Rural Development 2021), the MCC for western hemlock occurs at about 298 years of age and the average total biomass at this age is 470 t of above-ground biomass per ha on a dry basis.

Gray et al. (2015) characterized the carbon accumulation in Pacific Northwest forests. The MCC for non--hemlock species was estimated by the study authors based on the site index of the stand; the site index is the stand height in metres at the index age of 50 years.

For each stand, the total above-ground biomass was calculated including the stem, bark, foliage, and branches. A 50% carbon percentage of dry tree was applied to establish the tonnage of carbon per ha (Trees for the Future nd).

The term AgeMCC – AgeCurrent was estimated following guidance in the draft Technical Guide (ECCC 2021). In cases where the existing forest stand age was greater than the age at MCC (318 to 349 years of age), the natural flux is positive, indicating a carbon source rather than a carbon sink. None of the Forest Land was found to have stand ages less than the age at MCC. As per the draft Technical Guide, the AgeMCC – AgeCurrent term was set to 100 years because the assessment is limited to a 100-year period.

Details on the assessment for each stand are provided in Table 2.2–1.

With respect to natural flux from bogs, Site- or region-specific data were not available. The default mean annual carbon flux provided in Table 31 of the draft Technical Guide for the Atlantic Maritime ecozone was selected to represent the conditions present in the Pacific Maritime ecozone.

Table 2.2–1 Forest Land Details

Stand No.	Dominant Species	Second Dominant Species	Site Index (m)	Biomass Total (t/ha)	Current Carbon Content Total (t C/ha)	MCC Carbon Content Total (t C/ha)	Current Age (years)	MCC Age (years)	Years Above MCC Age (years)	Natural Flux (t C/ha/yr)
1	Western Redcedar	Western Hemlock	9.8	272	136	440	329	262	67	Positive
2	Western Redcedar	Western Hemlock	18.1	569	284	440	349	262	87	Positive
3	Western Redcedar	Western Hemlock	12.2	334	167	440	329	262	67	Positive
4	Western Hemlock	Spruce	12.3	553	277	470	349	298	51	Positive
5	Western Hemlock	Western Redcedar	10.4	423	212	470	329	298	31	Positive
6	Western Hemlock	Western Redcedar	8.8	313	156	470	329	298	31	Positive
7	Western Hemlock	Spruce	17.9	805	402	470	349	298	51	Positive
8	Western Hemlock	Spruce	13	591	296	470	329	298	31	Positive
9	Western Hemlock	Western Redcedar	12.5	480	240	440	318	262	56	Positive

NOTE:
t C/ha is tonnes of carbon per hectare

2.2.3 Disturbance Activity

For the carbon sinks assessment, it is assumed that for all Forest Land and Wetland, the Project will completely interrupt the carbon sink capacity of the land. It follows, therefore, that the land within the Project footprint will have a Post Flux of 0 t C/ha/y. This approach is consistent with the default assumption shown in Annex D of the draft Technical Guide (ECCC 2021).

2.3 RESULTS

For the stand that was found to be sequestering carbon, the estimated values of the CSI are presented in Table 2.3–1.

Table 2.3–1 Carbon Sink Impact Results – Forest Land

Stand No.	Years	Natural Flux (t C/ha/yr)	Post Disturbance Flux (t C/ha/yr)	Area (ha)	Carbon Sink Impact (t C)
1 through 9	100	Positive	0	26.0	0
NOTE: Negative indicates emissions.					

Because the natural flux from Forest Land is positive, the CSI for the Project from disturbance of Forest Land is zero.

The estimated CSI from disturbance of wetland within the Project footprint is 218 t C. For context, if this amount of carbon was burned, it would generate approximately 800 t of carbon dioxide (**CO_2**), which is approximately how much 245 passenger cars would release in one year of driving (NRCan nd).

2.4 ASSUMPTIONS AND LIMITATIONS

The methodology used to estimate the CSI for the Forest Land is the approach described in the draft Technical Guide. The SACC-provided default mean annual carbon flux for the Atlantic Maritime ecozone was used to represent annual carbon flux in the Pacific Maritime ecozone. This approach, without any Site- or region-specific data, introduces uncertainty into the estimation of the wetland CSI.

Estimated age and biomass tonnages of trees from the BCLCS with respect to the Project area, as well as information on age and biomass content from the BCLCS, were used to estimate the MCC age and biomass content for the western hemlock in the Pacific Maritime ecozone. Information taken from the Gray et al. (2015) study on the MCC of non-hemlock species was used; there may be limitations on the information that are beyond the scope of this carbon sinks assessment.

3.0 THE PROJECT AND CANADA'S EFFORT TO REDUCE GREENHOUSE GAS

3.1 INTRODUCTION

This section addresses the impact of the Project on Canada's efforts to reduce GHG emissions as well as how the Project could impact global GHG emissions as required under Section 5.1.3 of the SACC.

The Project is an opportunity to meet growing global natural gas demand with LNG that has a lower GHG emissions intensity versus other global projects; the Project is expected to have one of the lowest GHG LNG emission profiles in the world. From a regional environmental perspective, the Project will be net-zero primarily through the use of renewable electricity and the offsetting of remaining direct and indirect GHG emissions. The Project could not only help meet the increasing global demand for LNG but may also play a role in reducing GHG emissions from primary energy demand.

The estimated GHG emissions from the Project are expected to be a small fraction of BC's and Canada's total emissions. BC is committed to reducing GHG 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% to 38% of 2007 levels by 2030, including that all new LNG facilities pass an emissions test with a credible plan to be net-zero by 2030 (Government of British Columbia 2023). Although the Project will release GHG emissions, The Project will be net-zero ready by 2030 and these releases will be mitigated through the Project's credible net-zero plan.

Two Project cases are considered: the Base Case and the Alternative Case. In the Base Case, a connection to the BC Hydro electrical grid is available at the start of Project operation. The Alternative Case assumes that sufficient power is unavailable at start up, which would require the Project to install and use temporary power barges to provide necessary power needs. For illustrative purposes, 2032 was chosen as the year that the interconnection is completed (i.e., the facility uses grid electricity starting in 2033).

3.2 CONSIDERATION OF CANADIAN CLIMATE POLICIES

The provincial, national, and Canadian sector GHG emissions from all reportable activities in BC and Canada for 2021 are provided in Table 3-1. Canadian GHG emissions were estimated to be 670,000,000 metric tonnes (**t**) carbon dioxide equivalent (**CO_2e**) in 2021. BC's contribution to national GHG emissions is 9% (59,400,000 t CO_2e). Greenhouse gas emissions from the oil and gas sector represent 28% of Canada's total GHG emissions (189,000,000 t CO_2e) and 21% of BC's total GHG emissions (12,400,000 t CO_2e).

Table 3.2–1 Canada, British Columbia, and Oil and Gas Sector 2021 Greenhouse Gas Emissions

Region	GHG Emissions ($t\ CO_2e$)
Canada [a]	670,428,000
British Columbia [a]	59,436,000
Canada sector [a] (oil and gas)	189,000,000
British Columbia sector (oil and gas)	12,400,000

NOTE:

[a] 2021 Canada and British Columbia emission totals, and Canadian and British Columbia Oil and Gas sector GHG emission totals, were used for comparison (as presented by Economic Sector in the National Inventory Report Table A10-2 and A11-21 [ECCC 2023a]).

Greenhouse gas reduction targets within BC have been legislated since 2007 under the *Greenhouse Gas Reduction Targets Act* (re-titled the *Climate Change Accountability Act* in 2018). Greenhouse gas targets are set as 40%, 60%, and 80% below the 2007 GHG emission levels by 2030, 2040 and 2050, respectively. There is also an interim target of 16% by 2025. The Minister of Environment and Climate Change Strategy established targets for transportation, industry, oil and gas, and buildings and communities in March 2021. Currently, BC's GHG inventory does not include a specific category for LNG facilities, however such emissions may be considered under the oil and gas category. For the oil and gas sector, the target range is a reduction of 33% to 38% by 2030, compared to 2007 levels (Government of British Columbia 2022). On March 14, 2023, the Government of British Columbia announced its New Energy Action Framework that will: (i) require all proposed LNG facilities in or entering the environmental assessment process to pass an emissions test with a credible plant to be net-zero by 2030, (ii) establish a regulatory emissions cap for the oil and gas industry; and (iii) create a BC Hydro task force to accelerate the electrification of BC's economy (Government of British Columbia 2023).

Table 3-2 below provides the Government of Canada's 2030 GHG reduction targets, the Government of BC's 2030, 2040, and 2050 reduction targets, and the Government of British Columbia's sectoral 2030 emission reduction targets. The reduction target is the reduction below a baseline year.

Table 3.2–2 Canada, British Columbia, and Oil and Gas Sector Greenhouse Gas Reduction Targets

Target		GHG Emissions in Target Years (t CO_2e)
Government of Canada 2030 GHG Reduction Target [a]		402,720,450–439,331,400
Government of British Columbia GHG Reduction Target [b]	2030	38,040,000
	2040	25,360,00
	2050	12,680,000
Government of British Columbia Sectoral 2030 GHG Reduction Target (Oil and Gas) [c]		7,512,000–8,142,000

NOTES:

[a] 30% reduction from the 2005 Canada emission total as reported in the National Inventory Report Table A10-2 (ECCC 2023a).

[b] 40%, 60%, and 80% reduction from the 2007 British Columbia provincial emission total as reported in the CleanBC Sectoral GHG Targets Modelling Methodology (Government of British Columbia 2021).

[c] 33–38% reduction from the 2007 British Columbia Oil and Gas emission totals as reported in the CleanBC Sectoral GHG Targets Modelling Methodology (Government of British Columbia 2021).

The Project is expected to have a GHG emissions-intensity lower than any other LNG facility in the world, once BC Hydro grid connection occurs. Consistent with Canada's Strengthened Climate Change Plan, the Project will create economic growth and ensure Canadians continue to have good-paying jobs while providing lower GHG emissions intensity products the world wants to buy now and into the future. LNG produced in Canada achieves substantive carbon reductions across the LNG value chain on a well-to-market basis when compared to other LNG exporting countries (Section 4.0).

3.2.1 Comparison to National and Provincial GHG

Emissions from the Project would represent a fraction of national and provincial GHG totals, and under the Base Case, would represent the lowest GHG intensity in the LNG sector.

The provincial and national total GHG emissions reported in the National Inventory Report are presented without including emissions associated with land-use, land-use change, and the forestry sector. As such, Project GHG emissions from construction activities other than land-use change are compared to the 2021 emissions from Canada, BC, and the Canadian and British Columbian sector (oil and gas). Similarly, comparisons to the emission reduction totals exclude land-use change.

The total emissions from Project construction, excluding land-use change and commissioning, are estimated to be 45,381 t CO_2e over the period of 2025 to 2028 (3 to 4 years); this represents approximately 11,345 t CO_2e/y. Using the 2021 Canada, BC, and oil and gas sector totals as a baseline, annual average direct emissions from Project construction represent approximately 0.02% of the BC and approximately 0.002% of the Canada GHG emissions totals (see Table 3.2–3).

The Project construction will emit 0.003% of the Government of Canada's 2030 GHG emission reduction target and 0.03% of the Government of BC 2030 emission reduction target. Construction will be completed prior to 2030; therefore, Project construction emissions are not further compared to 2040 or 2050 reduction targets.

Table 3.2–3 Comparison of Estimated Direct Annual Construction Emissions to Canada and British Columbia Greenhouse Gas Emission Totals

Canada[a]		British Columbia[a]	
CO_2e (t/y)	Project Comparison[b] (%)	CO_2e (t/y)	Project Comparison[b] (%)
670,428,000	0.002	59,436,000	0.02

NOTES:

[a] 2021 British Columbia and Canada emission totals and British Columbia and Canada Oil and Gas sector GHG emission totals used for comparison. These represent the most recent data available (ECCC 2023a).

[b] Project comparison assumes gas turbines are used for commissioning activities.

Using the 2021 Canada and BC emissions totals, the Project's operating emissions as presented in the Base Case in Section 6.0 will be 0.04% of the Government of Canada's current GHG emission and 0.4% of the Government of BC 2021 emissions (Table 3.2–4). Project operations (Base Case net emissions before offsets are considered) will annually emit 0.05% of the Government of Canada 2030 GHG emission reduction target and 0.59%, 0.84% and 1.68% of the Government of BC 2030, 2040, and 2050 emission reduction targets, respectively. When compared to the 2030 sectoral reduction target for oil and gas in BC, the Project operation emissions (Base Case net emissions before offsets are considered) will annually emit 2.7% to 3.0% of the BC Government's 2030 sectoral reduction target for the oil and gas sector.

Under the Alternative Case (discussed in Section 6.0), in 2030 the Project will represent approximately 3% of the BC GHG emissions total, 0.3% of Canada's GHG emissions total, 15% of the BC oil and gas sector total, and 1% of the Canada oil and gas sector total. As shown in Section 6.0, the Project anticipates that emissions from the Alternative Case will equal emissions in the Base Case by 2033.

Table 3.2–4 Comparison of Estimated Direct Annual Operation Emissions to Canada and British Columbia Greenhouse Gas Emission Totals – Base Case and Alternative Case

Canada[a]		British Columbia[a]		British Columbia Sector[a] (Oil and Gas)		Canada Sector[a] (Oil and Gas)	
CO_2e (t/y)	Project Comparison (%)	CO_2e (t/y)	Project Comparison (%)	CO_2e (t/y)	Project Comparison (%)	CO_2e (t/y)	Project Comparison (%)
670,428,000	0.04 (Base)	59,436,000	0.4 (Base)	12,400,000	2 (Base)	189,000,000	0.1 (Base)
	0.3 (Alternative)		3 (Alternative)		15 (Alternative)		1 (Alternative)

NOTE:
[a] 2021 British Columbia and Canada emission totals and British Columbia and Canada Oil and Gas sector GHG emission totals used for comparison. These represent the most recent data available (ECCC 2023a).

Table 3.2–5 Comparison of Estimated Direct Annual Operation Emissions to Canada, British Columbia, and Oil and Gas Sector Greenhouse Gas Emission Reduction Targets – Base Case (Net Emissions Before Offsets)

Government of Canada 2030 GHG Reduction Target		Government of British Columbia GHG Reduction Targets [a]						Government of BC Sectoral 2030 GHG Reduction Target [b]	
CO_2e (t)	Project Contribution (%)	CO_2e (t)			Project Contribution (%)			CO_2e (t)	Project Contribution (%)
		2030	2040	2050	2030	2040	2050		
402,720,450–439,331,400	0.05	38,040,000	25,360,000	12,680,000	0.59	0.84	1.68	7,512,000–8,142,000	2.7–3.0

NOTES:
[a] 40%, 60% and 80% reduction from the 2007 British Columbia provincial emission total as reported in the CleanBC Sectoral GHG Targets Modelling Methodology (Government of British Columbia 2021).
[b] 33–38% reduction from the 2007 British Columbia Oil and Gas emission totals as reported in the CleanBC Sectoral GHG Targets Modelling Methodology (Government of British Columbia 2021).

3.3 THE PROJECT AND IMPACT ON GLOBAL EMISSIONS

Natural gas is projected to remain a critical supply of primary energy to meet the growing needs of consumers globally (Shell 2023, Woodmac 2022, Platts 2023, BP 2023). Demand for natural gas, particularly in Asia, is expected to continue growing (Shell 2023). Global LNG prices hit record high levels in Q4 2021, and demand is expected to nearly double in the next twenty years (Shell 2021, Woodmac 2022). According to the Gas Exporting Countries Forum, global natural gas demand is projected to increase 36% by 2050 with LNG demand more than doubling between 2021 and 2050 (GECF 2022).

As the global economy balances increasing demand for LNG and transitioning to a lower GHG emissions intensity economy, the risk of carbon leakage if the Project is not built in Canada is high. The carbon intensity of natural gas produced outside of Canada is significantly higher than natural gas produced within Canada (Rockies LNG 2023). Increased demand for LNG could be met with new supply from countries with less-stringent emissions regulations, if that demand is not met with Canadian LNG.

Over the last decade, increased global LNG demand has been largely filled by the US as natural gas production and LNG export capacity have increased significantly. US LNG total baseload export capacity increased from less than 1 billion cubic feet per day (Bcf/d) in 2015 to 10.78 Bcf/d at the end of 2021 (EIA 2022). Total peak export capacity in 2021 was 12.98 Bcf/d. In 2015, total US LNG exports were about 28 Bcf to seven countries. In 2021, US LNG exports reached a record high of about 3,561 Bcf delivered to 45 countries (US EIA 2022). The US EIA projects that US LNG exports will nearly double by 2050 to meet international demand (EIA AEO2023).

If insufficient natural gas supply is available to meet growing primary energy demand, the market will likely turn to other higher GHG emissions intensity alternatives such as coal and fuel oil to meet growing energy needs. As noted by the IEA, as global LNG prices hit record high levels due to, among other factors, the global energy crisis, countries turned to coal as a substitution for gas, leading to a growth in CO_2 emissions of 1.6% or 243 Mt and reaching a new all-time high of almost 15.5 Gt (IEA 2023a). This trajectory is expected to continue through 2023, when coal consumption is predicted to grow to historic new highs (IEA 2023a).

Demand for natural gas globally is and will continue to be met through facilities that have a significantly higher carbon footprints than those built in Canada, including the Ksi Lisims LNG Project (see Figure 3.3–1). When comparing the Project's facility emissions to LNG facilities (Figure 3.3–1) from other supply regions internationally, this potential benefit ranges from 10 to 20 times fewer GHG emissions per tonne of LNG. Put another way, the Project would emit 3 to 5 million tonnes less CO_2e per year than an average LNG facility in operation today, and 90 to 150 million tonnes less CO_2e over the estimated life of the Project. Furthermore, these estimates do not account for the Project's use of offsets for its scope 1 and 2 emissions as per the net-zero plan.

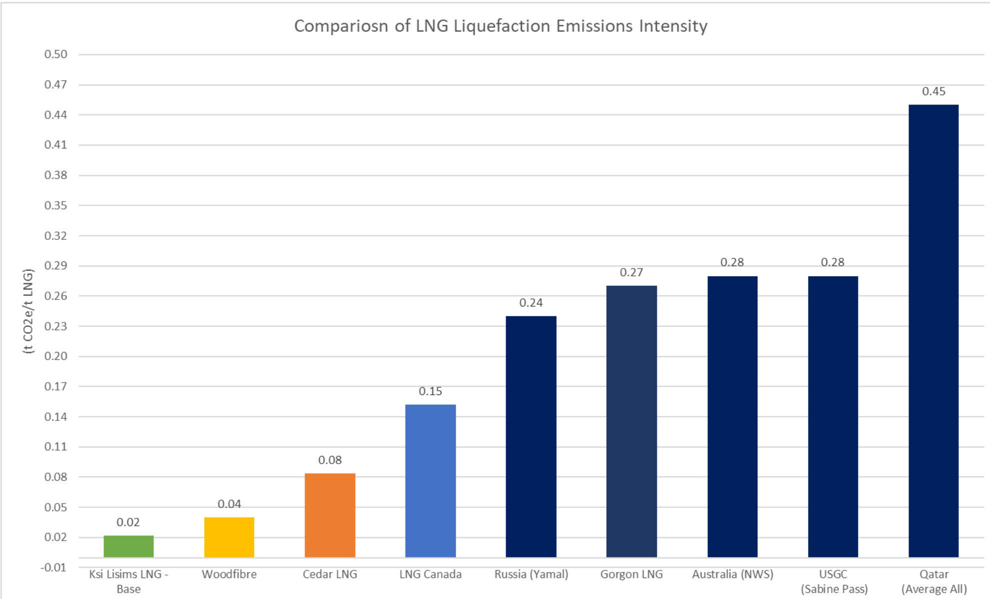

Figure 3.3–1 Comparison of LNG Liquefaction Emissions Intensity[1]

A wide range of scenarios have been published by various organizations (e.g., EIA, Woodmac, Shell, BP, GECF) on global natural gas supply, demand, and resulting GHG emissions. Given constantly evolving energy markets, economies, geopolitical events, and climate policies these predictions vary significantly in their estimation of global natural gas and LNG demand. As outlined by the Canadian Energy Regulator scenarios that are the product of policy assumptions can generate results that may not align with more data-driven modeling. Moreover, reliance upon one scenario to inform the understanding of complex global energy outlooks will have a high probability of erroneously assessing supply and demand. Demand scenarios can be assessed in the context of both data driven forecasting and the multiple pathways to achieving climate targets, which can vary significantly from jurisdiction to jurisdiction. A jurisdiction's particular pathway will be influenced by numerous factors including: evolving societal preferences, regulatory frameworks, socioeconomic conditions, and affordability considerations. As detailed in robust modelling work from the IPCC, there are multiple pathways to achieve climate targets over time (IPCC 2022).

One prediction that most, if not all, energy outlook or climate scenarios — including the IEA's Net-Zero Roadmap and the CER's Canada's Energy Future 2023 — agree on is that natural gas will be required up to and past 2050. As an opportunity to reduce emissions, IPCC assessments show that climate goals can be partially met by delivering GHG reductions through well-executed fuel switching, including from coal to natural gas (IPCC 2022). Lower emission LNG may not impede achievement of local or global climate goals and is an important part of the global energy supply system going forward. As illustrated above, demand for natural gas will remain high for decades to come, and if the Project is not built in Canada, LNG will likely be supplied by facilities with significantly higher emissions. Given there exists a high risk of

[1] Source: CSIRO Energy 2019, Delphi Group 2013, Qatargas 2020, Nakilat 202, ERM 2020, ACS Sustainable 2021, Roman-White et al. 2019, Novatek 2021, Woodside 2019.

carbon leakage if the Project is not built in Canada, under any projection or scenario, the Project's emissions are not expected to be incremental on a global scale. As outlined in this Application, the Project minimizes direct emissions, will be the largest low GHG emissions intensive facility in the world, and has a credible plan to be net-zero ready by 2030.

4.0 UPSTREAM ASSESSMENT

4.1 INTRODUCTION

Upstream GHG emissions are defined in Section 3.2 of the draft Technical Guide of the SACC as the domestic and non-domestic emissions associated with all stages of production, from the point of resource extraction up to but not including the Project under review (Environment and Climate Change Canada, August 2021). This is interpreted to include emissions for production, gathering, processing, and transmission of the natural gas supplied to the Project.

In accordance with Section 5.1 of the draft Technical Guide, the assessment has been divided into two parts:

- Part A: Quantitative estimate of upstream GHG emissions
- Part B: Qualitative discussion of the incrementality of upstream GHG emissions

4.2 PART A – ESTIMATION OF UPSTREAM GREENHOUSE GAS EMISSIONS

4.2.1 Upstream Activities and Products

The Project will process and liquefy approximately 1.7–2.0 billion standard cubic feet per day (Bcf/d) of natural gas sourced from the WCSB of northeastern BC and northwest/central Alberta. The activities upstream of the Project include natural gas extraction, field gathering and processing, and natural gas gathering and transmission to the Project.

Upstream activities will be located entirely in Canada. Natural gas extraction, gathering and processing will occur in BC and Alberta, and the natural gas transmission line will originate in northeastern BC and transport natural gas across the province to the Project Site. There will be no international contribution of upstream GHG emissions.

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 upstream emissions. Generation of purchased electricity, hydrogen, or steam used for the Project is also excluded as these are considered in the Project's net GHG emissions as acquired energy.

4.2.2 Possible Scenarios

The upstream GHG emissions presented herein are based on the annual operating capacity of the Project. At full build-out, the Project will receive between 1.7 and 2 billion cubic feet per day (Bcf/d) (i.e., 48.1 and 56.6 million m^3 per day) of pipeline grade natural gas. The Project will connect to the BC Hydro grid for renewable power supply (Base Case). In the event the interconnection to the BC Hydro grid is not available for start-up, the Project proposes to use temporary floating power barges that use natural gas from the feed gas supplied to the Project (Alternative Case). Temporary power generation will allow the Project to produce LNG and meet contractual LNG delivery obligations until the BC Hydro grid connection is complete and operational, after which the power barges will be removed from Site.

For natural gas transmission to the Project Site, the proponent has entered into a commercial agreement with TC Energy to preserve the Prince Rupert Gas Transmission Project (PRGT) as the potential corridor to deliver natural gas to the Project.

4.3 UPSTREAM GHG EMISSION INTENSITIES

Upstream GHG emission intensities for natural gas production and processing and natural gas transmission contained in Tables 35 and 36 of the draft Technical Guide (ECCC 2021) were developed in 2020. As per guidance in the draft Technical Guide, more recent data was taken from the open data tables of Canada's Greenhouse Gas Emissions Projections webpage (ECCC 2023b). Emission intensities are presented in Table 4.3–1.

Table 4.3–1 Upstream GHG Emission Intensities

Upstream Activity	Unit	Year							
		2028	2029	2030	2031	2032	2033	2034	2035
Natural Gas Production and Processing	kg CO_2e/bbl eq	24.9	22.5	20.7	20.0	19.3	18.8	18.4	17.9[a]
Natural Gas Transmission	kt CO_2e/Bcf	1.41	1.40	1.38	1.38	1.38	1.38	1.38	1.38[b]

NOTES:
[a] Emission intensities for 2035 were used for 2036–2057 for natural gas production and processing
[b] Emission intensities for 2030 were used for 2031–2057 for natural gas transmission
bbl eq = barrel (of oil) equivalent
ECCC (2023b), Additional Measures scenario and ECCC (2021)

4.4 RESULTS

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

$$\text{Annual Product Upstream GHG Emissions} = \sum_{j}^{n} [EI_j \times PROD_j]$$

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

For this calculation:

- j = natural gas production and processing; natural gas transmission
- n = 2
- EI_j = emissions intensities provided in Table 4.3–1 for each respective activity
- $PROD_j$ =730 Bcf feed gas per year (corresponding to 2.0 Bcf/d) or 125 million barrels (of oil) equivalent (**bbl eq**) per year (at 6.05 bbl eq per 1000 m^3 of natural gas)

Table 4.4–1 presents the annual GHG emissions associated with the Project between 2028 and 2057. Total annual emissions range between 3,245 kt CO_2e and 4,141 kt CO_2e per year, with 70% to 75% of the upstream emissions attributable to the production and processing activities. Using the annual LNG production of the Project, the upstream emission intensity is approximately 0.27 t CO_2e/t LNG after 2034.

Table 4.4–1 Annual Upstream GHG Emissions

Year	Natural Gas Production and Processing (kt CO_2e)	Natural Gas Transmission (kt CO_2e)	Upstream GHG Emissions (kt CO_2e)	Emission Intensity (t CO_2e / t LNG)
2028	3,112	1,029	4,141	0.35
2029	2,812	1,022	3,834	0.32
2030	2,587	1,007	3,594	0.30
2031	2,500	1,007	3,507	0.29
2032	2,412	1,007	3,419	0.28
2033	2,350	1,007	3,357	0.28
2034	2,300	1,007	3,307	0.28
2035	2,237	1,007	3,245	0.27
2036	2,237	1,007	3,245	0.27
2037	2,237	1,007	3,245	0.27
2038	2,237	1,007	3,245	0.27
2039	2,237	1,007	3,245	0.27

Table 4.4–1 Annual Upstream GHG Emissions

Year	Natural Gas Production and Processing (kt CO_2e)	Natural Gas Transmission (kt CO_2e)	Upstream GHG Emissions (kt CO_2e)	Emission Intensity (t CO_2e / t LNG)
2040	2,237	1,007	3,245	0.27
2041	2,237	1,007	3,245	0.27
2042	2,237	1,007	3,245	0.27
2043	2,237	1,007	3,245	0.27
2044	2,237	1,007	3,245	0.27
2045	2,237	1,007	3,245	0.27
2046	2,237	1,007	3,245	0.27
2047	2,237	1,007	3,245	0.27
2048	2,237	1,007	3,245	0.27
2049	2,237	1,007	3,245	0.27
2050	2,237	1,007	3,245	0.27
2051	2,237	1,007	3,245	0.27
2052	2,237	1,007	3,245	0.27
2053	2,237	1,007	3,245	0.27
2054	2,237	1,007	3,245	0.27
2055	2,237	1,007	3,245	0.27
2056	2,237	1,007	3,245	0.27
2057	2,237	1,007	3,245	0.27

4.4.1 Assumptions and Limitations

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

- ECCC-estimated emission factors are available until 2030 (transmission) and 2035 (production and processing). Annual upstream emissions after 2035 were assumed to be the static.
- 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.

- Emission intensities were updated based on methods suggested in the draft Technical Guide using the Data Tables 2023 (ECCC 2023b). These intensities take into account additional polices and measures that are under development but have not yet been fully implemented, some of which were announced as part of the 2030 Government of Canada's Emission Reduction Plan.
- The assessment does not consider future changes to upstream emissions (post-2035) or transmission (post-2030) that may be driven by technology improvements, mitigation techniques or policy and regulatory requirements.

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

4.5.1 Introduction

Part B of the upstream GHG emissions assessment assesses the incrementality of the upstream emissions estimated in Part A. The SACC draft Technical Guide defines incrementality as the increase in upstream production and resulting emissions that would only occur if the Project were built.

Following the guidance provided in the SACC draft Technical Guide, this section will address the following requirements:

- 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.

Within Canada, it is expected that any incremental upstream GHG emissions are likely to be lower than other jurisdictions, because of the emissions performance of the Western Canadian Sedimentary Basin (WCSB) producers, the existing Canadian regulatory framework, and the direction of current and future Canadian climate commitments and policies. As a result, any potential incremental upstream GHG emissions within Canada are not expected to be incremental on a global scale and are instead expected to achieve a net GHG reduction as upstream production could meet increasing demand by minimizing reliance on production from higher emission jurisdictions.

4.5.2 Incrementality of Upstream Emissions in Canada

4.5.2.1 Canadian Natural Gas Production and Emissions Outlook

The Canadian Energy Regulator (CER) released Canada's Energy Futures Report 2023 (EF2023), which provides information on Canada's energy supply and demand outlook to 2050, including natural gas production forecasts (CER 2023). EF2023 explores how energy futures might unfold for Canadians over the long term. In EF2023 the CER begins with the end goal in mind, net-zero GHG emissions in 2050 and use their models to identify pathways to that point. This is a different approach compared to past versions of the report where the models were run without restrictions, giving insights into what a given premise meant for the future.

The results in EF2023 are the product of scenarios based on a specific premise and set of assumptions. As noted by the CER, relying on just one scenario to understand the energy outlook implies too much certainty about what could happen in the future (CER 2023).

EF2023 contains two scenarios and one projection: Global Net-zero, Canada Net-zero, and Current Measures. In the Global Net-zero Scenario, the CER assumes Canada achieves net-zero emissions by 2050 and that the rest of the world reduces emissions enough to limit global warming to 1.5 Celsius (°C). In the Canada Net-zero Scenario, Canada is also assumed to achieve net-zero emissions by 2050, but the rest of the world moves more slowly to reduce GHG emissions. The Current Measures projection assumes status quo actions in Canada to reduce GHG emissions beyond measures in place today and does not require that Canada achieve net-zero emissions. In this projection the CER also assumes limited future global climate action.

In the Global Net-zero Scenario, Canadian production peaks at 17.4 Bcf/d (492 $E6m^3$/d) in 2023, because of relatively high gas prices in 2021 and 2022. After staying near those levels until 2026, production steadily falls to 5.5 Bcf/d (156 $E6m^3$/d) in 2050, because of lower investment in drilling new wells. Producer revenues decrease, largely because of lower natural gas prices, but also higher costs related to reducing emissions and complying with various climate policies. Exports of LNG from the first phase of the LNG Canada project begin in 2025 and ramp up to 1.7 Bcf/d (49.0 $E6m^3$/d) in 2026. This is the volume of natural gas that would be exported, accounting for natural gas used for fuel at the LNG facility. Woodfibre LNG begins production in 2028 and increases to full capacity of just below 0.3 Bcf/d (8.5 $E6m^3$/d) in 2029. Total exports in the Global Net-zero Scenario reach 2 Bcf/d (56.6 $E6m^3$/d) in 2029 and remain at that level until 2044. Under this scenario, in 2045, LNG production begins to fall in response to much lower global LNG demand, reaching 0.3 Bcf/d (8.5 $E6m^3$/d) by 2046 and staying at that level to 2050 (CER 2023).

In the Canada Net-zero Scenario, production rises to 17.7 Bcf/d (500 $E6m^3$/d) in 2030, because natural gas prices and LNG exports are higher than in the Global Net-zero Scenario. Production then falls to 11.0 Bcf/d (310 $E6m^3$/d) in 2050, largely because of falling gas prices which reduce producer revenue and investment in drilling new gas wells. LNG exports are expected to grow, starting at 1.0 Bcf/d in 2025 and reaching 3.8 Bcf/d by 2030, after which they remain flat (CER 2023).

In the Current Measures Scenario, as gas prices grow from 2023 to 2050, LNG exports are higher than in the other two scenarios, and climate policies are less stringent than in the two net-zero scenarios, and production rises to 21.5 Bcf/d (607 E6m³/d) in 2050. LNG Exports reach 4.6 Bcf/d (131.4 E6m³/d) in 2034 and staying at that level to 2050.

The incrementality of the upstream production associated with the Project to Canadian production will depend on a variety of factors and is difficult to assess with certainty. Most of these factors are outside the control of Canada – most notably natural gas supply and demand outside Canada and the pace of global climate action. In the Current Measures Scenario, the upstream production would likely be incremental to Canada to meet the substantial growth in demand. If the Global Net-zero scenario or Canada Net-zero scenario were to be realized, upstream production associated with the Project could be entirely incremental, not incremental at all, or a mixture of incremental and current production of Canadian supply.

Figure 4.5–1 shows the Canadian natural gas supply and demand balance forecasted in the Canada Net--zero scenario. The LNG export projects included in the Canada Net-zero scenario include Phase 1 and 2 of LNG Canada (3.4 Bcf/d) and Woodfibre LNG (0.3 Bcf/d). The Project is not included in the forecast of LNG exports and offers an opportunity to discuss the challenges in predicting incrementality.

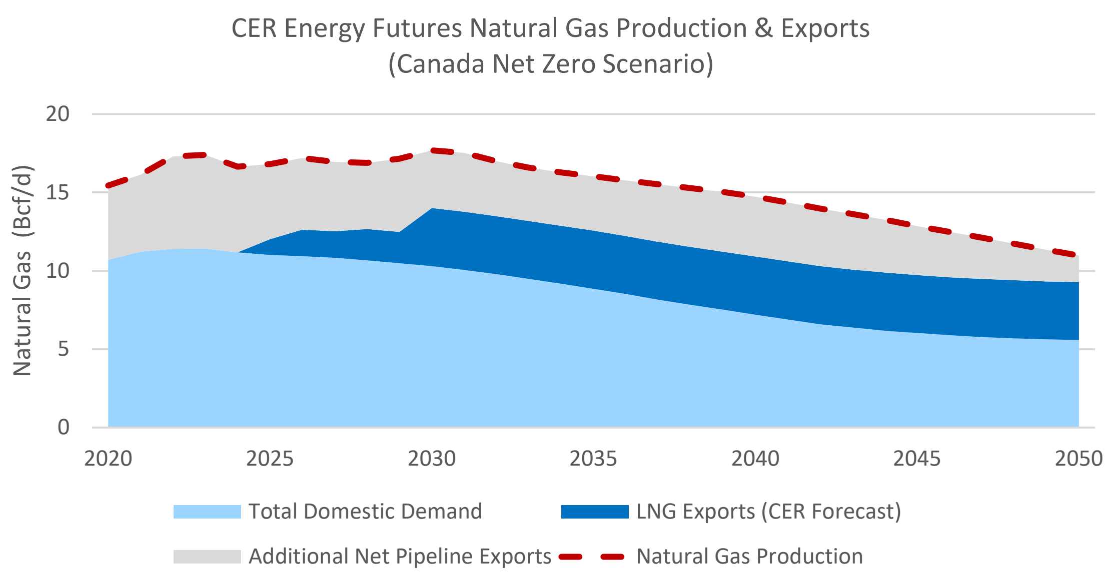

Figure 4.5–1 Canadian Natural Gas Supply and Demand Balance (CER 2023)

If the trajectory of natural gas was to follow the pathway of the Canada Net-zero scenario outlined in Figure 4.5–1, the upstream production associated with the Project could be entirely incremental as the Project was not considered in the scenario. However, numerous other reasonable pathways could transpire where the upstream production is not incremental including displacement of the additional net-pipeline exports or displacement of domestic demand due to faster declines in Canadian use.

As discussed in Section 3.3 the Gas Exporting Countries Forum projects global natural gas demand to increase 36% by 2050 with LNG demand more than doubling between 2021 and 2050 (GECF 2022). In addition, the US EIA sees US LNG exports potentially doubling by 2050 to meet international demand (US EIA AEO 2023). The Canadian natural gas market is not an island. It is entirely reasonable that in the face of increased growth in the US and globally that Canadian production would not decrease from 2030, but at the very least stay flat to meet increased demand in the US and globally. In this situation, the upstream production may not be incremental to current production but would be incremental in Canada to the Global Net-zero and Canada Net-zero scenarios presented by the CER.

It is likely that a portion of the upstream production associated with the Project will be incremental in the recent scenarios presented by the CER, but that some level of changing supply and demand flows will also divert existing production to west coast LNG. Given the large amount of uncertainty in any scenario, it is hard to assess the exact proportion.

4.5.2.2 The Impact on Canada's Emissions

In the Global Net-zero Scenario, emissions decline to 8 Mt in 2050, a decrease of almost 90% from 2021 levels. This is largely because of falling natural gas production, but also because of various climate policies, including federal regulations aiming to reduce methane (**CH_4**) emissions by 75% by 2030. Electrification of the sector, where feasible, and the use of carbon capture, utilization, and storage (CCUS) at larger natural gas processing plants also contribute to declining emissions. The Canada Net-zero Scenario follows a similar trend, with emissions falling to 9 Mt in 2050. In the Current Measures Scenario, emissions decline to 2030 before rising to 42 Mt in 2050 as production grows, and because policies do not become more stringent after 2030.

Assuming the Project's upstream emissions are fully incremental, the upstream emissions of 3.24-4.14 Mt CO_2e would contribute >1.0% to Canada's 2030 emissions. As Canada continues toward a net-zero by 2050 target and with the continued impact of climate policies and regulations, it is assumed that upstream emissions would decline to meet tightening legislation on GHG emissions.

Between 2005 and 2020, the Canadian natural gas sector achieved a 33% reduction in absolute production and processing greenhouse gas (GHG) emissions and 26% reduction in emissions intensity (Government of Canada 2022). This reduction has resulted from many initiatives, including electrification of operations, CCUS, fugitive emission management practices, adoption of zero-bleed instrumentation, waste heat recovery, and rapid adoption of new GHG reduction technologies. Many of these have been implemented by the producers that make up Rockies LNG (Rockies LNG 2023).

The CER Canada Net-zero Scenario is but one forecast for natural gas production in Canada. It is as credible to predict that natural gas production can rise to meet incremental demand from LNG export facilities in Canada while continuing to achieve a lower emissions intensity that still fits within federal GHG targets. This is reasonable especially considering that the many producers in the Western Sedimentary Basin have continued to improve their emissions performance due to a strengthening regulatory system and carbon pricing. It is possible for growth in natural gas production related to the Project (and other LNG facilities) that results in no incremental GHG emissions in Canada and does not impact the achievement of federal and provincial GHG reduction targets.

4.6 IMPACT OF UPSTREAM EMISSIONS GLOBALLY

4.6.1 Global Natural Gas Outlook

Natural gas is projected to remain a critical supply of primary energy to meet the growing needs of consumers globally (Shell 2023, Woodmac 2022, Platts 2023, BP 2023). Demand for natural gas, particularly in Asia, is expected to continue growing (Shell 2023). Global LNG prices hit record high levels in Q4 2021, and demand is expected to nearly double in the next twenty years (Shell 2023, Woodmac 2022). According to the Gas Exporting Countries Forum, global natural gas demand is projected to increase 36% by 2050 with LNG demand more than doubling between 2021 and 2050 (GECF 2022).

As outlined by the Canadian Energy Regulator, scenarios are the product of a specific premise and set of assumptions, and reliance upon one scenario to understand complex energy outlooks imputes too much certainty about what could happen in the future. One aspect that most, if not all, scenarios, predictions, and forecasts agree on is that natural gas will be required up to and past 2050 as part of a clean energy transition. The use and existence of natural gas does not necessarily impede achievement of local or global climate goals and is indeed an important part of the energy system going forward. It follows that, in a low-carbon economy, the primary source of natural gas or LNG should be that with the lowest well-to-market emissions intensity and that if the Project is not built in Canada the energy will likely be supplied by a facility with a higher emissions profile.

For the purposes of contextualizing the upstream production and emissions associated with the Project, the natural gas outlooks provided in the International Energy Association's (IEA's) recently published 2022 World Energy Outlook have been considered.

The IEA's 2022 World Energy Outlook includes three core scenarios that differ in the level of climate action and country contributions to meet climate targets. The Stated Policies Scenario (STEPS) reflects today's existing policies and measures under development. The Announced Pledges Scenario (APS) assumes that all major national announcements of climate targets are met on time and in full, including long-term net-zero and energy access goals (IEA 2022). The Net Zero Emissions by 2050 Scenario (NZE) demonstrates one potential pathway for the energy sector to achieve net-zero CO_2 emissions by 2050. (IEA 2021).

While natural gas demand varies significantly, all three scenarios forecast natural gas continuing to play some role in global energy supply over the next three decades and longer. The scenarios all emphasize the importance of having natural gas demand met with the lowest-carbon sources in order to meet critical environmental emissions targets.

In the STEPS, natural gas demand reaches 4,400 billion cubic metres (Bcm) in 2050, an increase of roughly 3% from 2021 (IEA 2022). While industrial natural gas use is the main driver of growth, this is partially offset by the buildings sector seeing falling demand due to efficiency improvements and adopting of heat pumps. With 17.5 Bcm per year of natural gas production, the Project would provide approximately 0.4% of total global demand in 2050. In the APS, natural gas demand declines to 2,700 Bcm in 2050, with most of the projected decline occurring after 2030 (IEA 2022). The upstream production associated with the Project would provide approximately 0.7% of total global demand in 2050.

While the NZE indicates a major contraction of natural gas and other fossil fuel production, natural gas demand is still forecast to be 1,700 Bcm in 2050 (IEA 2021). The upstream production associated with the Project would represent approximately 1.0% of the NZE's forecasted global gas demand in 2050. While natural gas use is expected to decline in the NZE and the IEA has suggested that it is possible to meet these demands without the need for new long lead time upstream conventional projects, "continued investment in existing oil and gas assets is essential in the NZE Scenario. This is to ensure that oil and gas supply does not fall faster than the decline in demand and also to reduce the emissions arising from oil and gas operations" (IEA 2023).

4.6.2 Impact on Global Emissions

Upstream natural gas production and associated GHG emissions are not expected to be incremental on a global scale, given the high risk of carbon leakage in the event the Project is not constructed. According to the IEA, the emissions intensity from natural gas operations will need to fall from just over 65 kg CO_2e per barrel of oil equivalent (bbl eq) in 2022 to just under 30 kg CO_2e/bbl eq by 2030 (IEA 2023). The upstream production associated with the Project is estimated to be 20.3 kg CO_2e/bbl eq in 2030, which is well below the reported forecasted average by the IEA (ECCC Open Data 2023).

All IEA scenarios show natural gas maintaining some role in the global energy mix. In addition, the Gas Exporting Countries Forum, EIA, Shell, and Wood Mackenzie all forecast increased LNG demand, in some cases nearly doubling by 2050. If the Project does not proceed, facilities with higher well-to-market emissions intensities would be developed or would continue producing to meet global demand.

Recently, global natural gas demand has been filled by the US as LNG export capacity and exports have increased significantly since 2015. US LNG total baseload export capacity increased from less than 1 billion cubic feet per day (Bcf/d) in 2015 to about 10.78 Bcf/d at the end of 2021. Total peak export capacity in 2021 was about 12.98 Bcf/d. In 2015, total US LNG exports were about 28 Bcf to seven countries. In 2021, US LNG exports reached a record high of about 3,561 Bcf to 45 countries (US EIA 2022). In addition, if insufficient LNG is available, the market will likely turn to additional higher carbon alternatives such as coal and fuel oil to meet energy needs, representing another risk of global carbon leakage if the Project is not built in Canada. As recently as 2022, high natural gas prices and shortages caused countries to turn back to coal, leading to higher global GHG emissions of nearly 243 Mt (IEA CO_2 Emissions in 2022). This trend is expected to continue through 2023, with record coal consumption predicted (IEA July 2023).

Figure 4.6–1 shows the comparison of well-to-port GHG intensities between the Project and other comparable LNG facilities. The Project will have a substantially lower well-to-port emissions intensities than comparable projects on the US Gulf Coast with between 0.76–1.19 tonne of carbon / tonne of LNG lower. At full production the Project will produce 9–14 million tonnes less CO_2e per year than a Gulf Coast terminal. This represents a global environmental benefit when growing demand is met with Canadian LNG and a clear illustration of the risk of global carbon leakage if the Project is not built in Canada.

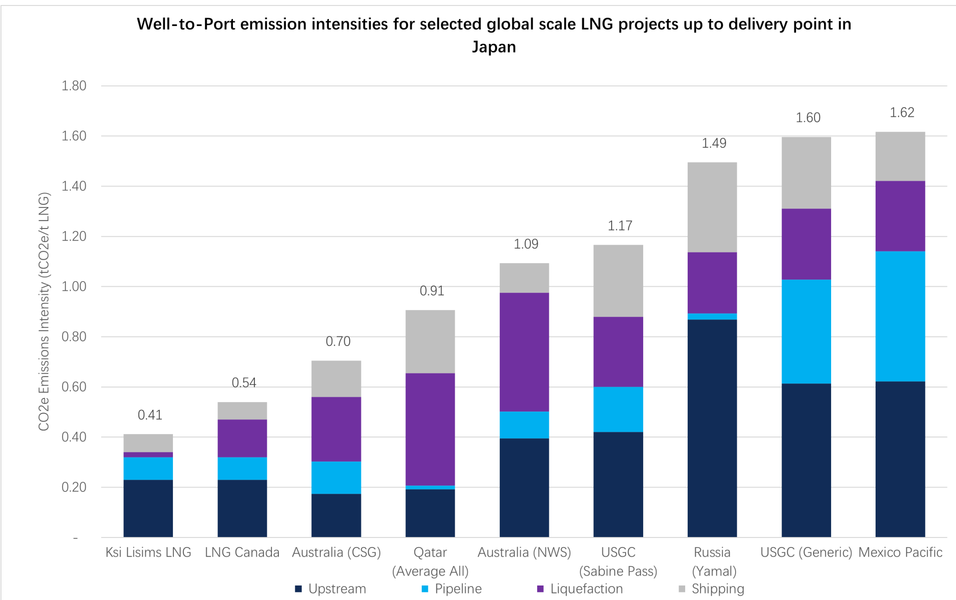

Figure 4.6–1 A Comparison of Well-to-Port Emissions[2]

[2] Source: BC EAO, ECCC 2023b, CSIRO Energy 2019. Delphi Group 2013. Qatargas 2020. Nakilat 2020. ERM 2020. ACS Sustainable 2021. NETL 2019. Novatek 2021. Woodside 2019.

4.7 IMPACT OF CLIMATE POLICIES ON UPSTREAM GHG INTENSITY

Part A of the upstream GHG emissions assessment provides a conservative estimate of upstream emissions. The expectation is that Rockies LNG producers and pipeline proponents will continue to lower their emission intensities over time to support provincial and federal reduction targets and Canada's commitment to net-zero emissions by 2050.

In 2015, Canada and 194 other countries reached the Paris Agreement, under which countries committed to the long-term goal to limit average temperature to well below 2°C and pursue efforts to limit the increase to 1.5°C. Canada committed to a target of reducing emissions 30% below 2005 levels by 2030, which was subsequently increased to 40–45% below 2005 levels by 2030. In 2021, Canada also enacted the Canadian Net-Zero Emissions Accountability Act, which enshrines in legislation Canada's commitment to achieve net-zero emissions by 2050.

To achieve its Paris Agreement commitments and domestic net-zero targets, the Canadian and British Columbian governments have introduced successive climate measures aimed at reducing GHG emissions in Canada's oil and gas sector:

- Oil and gas sector emissions cap at 31% below 2005 (or 42% below 2019) levels by 2030
- 75% reduction in oil and gas methane emissions from 2012 levels by 2030
- Carbon Capture, Utilization and Storage (CCUS) investment tax credits
- CleanBC Roadmap to 2030
- BC New Energy Action Framework
- Federal Clean Electricity Standard
- Energy Innovation Program
- Clean Growth Program
- Emissions Reduction Fund
- Clean Fuel Regulations
- Pricing carbon pollution

While the emissions cap and methane emission reductions are sectoral level commitments, Rockies LNG producers and the Project's pipeline proponent are expected to continue adopting best available technologies and following federal and provincial directives, such as Directive 60 released by the Alberta Energy Regulator (AER) and amendments to the Drilling and Production Regulation by the BC Energy Regulator requiring oil and gas companies to address fugitive emissions and venting, which are the primary sources of methane emissions.

WCSB Producers and the producers of Rockies LNG are actively and continually identifying and implementing decarbonization opportunities for their operations, such as:

- Clean electrification of well sites, facilities or transport equipment, reducing GHG emissions from fuel combustion
- Carbon capture and sequestration, which can mitigate significant pre- or post-combustion CO_2 emissions
- Methane abatement through continuous leak detection and repair, such as aerial methane detection equipment over pipeline corridors and well sites
- Methane abatement through the use of zero-bleed pneumatic devices on all new well sites to eliminate methane venting, and retrofitting all pneumatic gas devices by the AER's 2023 compliance deadline
- Energy efficiencies and process improvements, including waste heat recovery to lower fuel gas requirements
- Use of cleaner fuels in operations, such as replacing diesel with compressed natural gas in drilling and completions operations
- Minimizing flared emissions through in-line testing of new production on all well pads

5.0 BEST AVAILABLE TECHNOLOGY AND BEST ENVIRONMENTAL PRACTICES DETERMINATION

The objective of this BAT/BEP determination is to illustrate how the Proponents have 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) as well as the draft guidance for best-in-class GHG emissions performance by oil and gas projects (ECCC 2022a) and includes:

1. A list of all available and emerging technologies and practices that are relevant to the Project
2. A technical feasibility assessment
3. A GHG reduction potential assessment
4. An economic feasibility assessment
5. Consideration of any other factors that affect BAT/BEP determination
6. The selected BAT/BEP

5.1 RELEVANT PROJECT DETAILS

The Project Site is remote, accessible only by boat and located approximately 15 km west of the nearest community of Gingolx (Figure 1–1). There is currently no infrastructure for an electrical grid connection or natural gas pipeline in the Project Area.

The Project will convert Canadian natural gas from the Western Canadian Sedimentary Basin of northeastern BC and northwest/central Alberta to LNG. Natural gas will be transported to the Site via a pipeline originating in northeastern BC. At full build-out, the Project will receive between 1.7 and 2 Bcf/d (i.e., 48.1 and 56.6 million cubic metres (**m^3**) per day) of pipeline grade natural gas and produce up to 12 MTPA of LNG using two FLNG units. In addition to LNG, a small amount (ten to twelve shipments per year) of natural gas liquids (**NGL**) will also be generated. LNG carriers (**LNGC**s) and NGL product vessels will arrive periodically to offload product from the Project for delivery to market.

The Project has the potential to support the Nisg̱a'a Nation and other Indigenous nations’ goals of responding to climate change while enabling economic development. The Nisg̱a'a Nation are founding members of the First Nations Climate Initiative (**FNCI**). FNCI (2022) is an Indigenous led policy initiative focused on assisting Canada, BC, Alberta, and Indigenous nations in meeting international, national, provincial and Indigenous nation objectives to address global climate change due to GHG emissions. A major policy initiative of FNCI is the promotion of net-zero LNG as a transition step to the low carbon economy of the future while supporting “economic self-determination and restoration of traditional territories”. It is important to the Nisg̱a'a Nation that the foundational approach to the Project from the start was a design that could achieve net-zero LNG production as early as possible and is consistent with the objectives of the FNCI.

5.2 TECHNOLOGIES AND PRACTICES

Established and emerging technologies and practices were identified 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 5.2–1. 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 5.2–1 (e.g., firewater pumps).

Table 5.2–1 List of Best Available and Emerging Technologies

Phase/Year	Source	Available Technologies	Emerging Technologies
Construction	Carbon sinks	• None	• None
	On-land equipment (off-road and on-road)	• Diesel fueled • Biodiesel fueled • Renewable diesel • Electric (battery) • CNG	• LNG fueled • Hydrogen-based electric
	Marine equipment	• Marine diesel fueled • Dual fuel diesel/LNG fueled • Hybrid diesel/electric • Electric (battery)	• Ammonia fueled • Hydrogen-based electric
Operations	Primary energy source (electricity)	• Connection to BC electricity grid • Simple or combined cycle gas turbines on-Site • On-Site steam turbine with biomass combustion • Wind energy • Solar energy	• None
	Back-up/emergency energy source	• Natural gas engine generators • Diesel generators	• Energy storage (battery, hydrogen)
	Waste gas containing CO_2	• Thermal oxidizer with natural gas combustion to support • Flare with natural gas combustion to support • Carbon capture, utilization, and storage (**CCUS**) prior to destruction equipment • Venting	• None

Table 5.2–1 List of Best Available and Emerging Technologies

Phase/Year	Source	Available Technologies	Emerging Technologies
Operations (cont'd)	Fugitives	• Reduction of flanges and other emission points by using welded connections • Specially designed valves that have lower leak rate from stems • Capture, compression, and re-liquefaction of boil-off gas (**BOG**) • Flaring of BOG	• None
	Disposal of natural gas during maintenance, upset, or emergencies	• Flaring • Thermal oxidizer • Venting	• None
	LNG carriers in transit	• Dual fuel BOG and marine fuel • Marine fuel	• None
	LNG carriers at terminal	• Dual fuel BOG and marine fuel • Shore-based electricity • Marine fuel	• None
	Tugboats in transit	• Marine fuel • Dual fuel diesel/LNG • Electricity (battery) with fossil fuel back-up	• None
	Tugboats at terminal	• Marine fuel • Dual fuel diesel/LNG • Electricity (battery) with fossil fuel back-up	• None
Decommissioning	On-land equipment	• Diesel fueled • Biodiesel fueled • Renewable diesel • Electric (battery) • CNG fueled	• Hydrogen-based electric • LNG fueled
	Marine equipment	• Marine fuel • Dual fuel marine fuel/LNG fueled • Electric (battery)	• Ammonia fueled
	Carbon sinks	• None	• None

The practices that are considered in the BEP Determination are listed in Table 5.2–2. Depending on the BAT technically feasible assessment, some practices listed in Table 5.2–2 may not be relevant.

Table 5.2–2 List of Best Available and Emerging Practices

Phase/Year	Source	Available Practices	Emerging Practices
Construction	Carbon Sinks	• Biomass burning • Biomass chipping and spreading • Storage and decomposition • Site remediation • Merchantable timber recovery	• None
	On-land equipment (off-road and on-road)	• Anti-idling policy • Optimal sizing • Regular maintenance • Fuel consumption monitoring	• None
	Marine equipment	• Optimal sizing • Regular maintenance • Fuel or electricity consumption monitoring • Energy efficiency measures	• None
Operations	Primary energy source (electricity)	• Energy efficiency measures • Regular maintenance of equipment (on-Site only) • Measurement of electricity consumption • Hydrogen blending • Monitoring carbon content of hydrocarbon fuels.	• None
	Back-up/emergency energy source	• Energy efficiency measures • Regular maintenance of equipment • Measurement of electricity consumption	• None
	Waste gas containing CO_2	• Optimal sizing • Fuel monitoring • Regular maintenance • Energy efficiency measures	• None

Table 5.2–2 List of Best Available and Emerging Practices

Phase/Year	Source	Available Practices	Emerging Practices
Operations (cont'd)	Fugitives	• Leak Detection & Repair (**LDAR**) program using surveys	• Use of satellites, drones, or mobile sensors to monitor and identify leaks
	Disposal of natural gas during maintenance, upset, or emergencies	• None	• None
	LNG carriers in transit	• None	• None
	LNG carriers at terminal	• None	• None
	Tugboats in transit	• None	• None
	Tugboats at terminal	• None	• None
Decommissioning	On-land equipment	• Anti-idling policy • Optimal sizing • Regular maintenance • Fuel consumption monitoring	• None
	Marine equipment	• Anti-idling policy • Optimal sizing • Regular maintenance • Fuel or electricity consumption monitoring • Energy efficiency measures	• None
	Carbon Sink	• Site remediation	• None

A description of the various technologies and practices being considered can be found in the following paragraphs.

5.2.1 On-land and Marine Equipment

On-land construction equipment includes the use of heavy machinery such as bulldozers, excavators, graders, and cranes, as well as pick-up trucks. Diesel is the fuel typically used by off-road construction equipment; some smaller off-road equipment and on-road equipment may use gasoline or propane. The focus of this assessment is on equipment that is large enough to use diesel; gasoline or propane powered equipment during typical construction projects do not contribute substantively to GHG emissions.

Marine equipment includes self-propelled barges, ferries, or tugs. These are typically fueled by marine diesel.

The construction and decommissioning equipment units are assumed to be contractor-operated under construction contracts. Fleet maintenance activities will be performed either at the Project Site or at the contractor's maintenance facilities.

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

5.2.2 Primary Energy Source

Stationary equipment units that require energy in the form of electricity or heat to operate require a reliable primary energy source. This energy source may be located at the Project or located distantly with appropriate equipment to transport the energy to the Project. For this assessment, five existing energy sources and one emerging energy source are considered.

5.2.3 Back-up / Emergency Energy Source

When the primary energy source is unavailable due to maintenance of the energy source, an unplanned outage, or during emergencies, a reliable back-up system is required to safely shutdown equipment and ensure the health and safety of personnel. Such systems are typically fossil-fuel based as they are readily available, reliable, and can be tested for readiness periodically. Two existing technologies and one emerging technology are included in the assessment.

5.2.4 Waste Gas Containing CO_2

The waste gas stream consists mostly of CO_2 with some sulphur compounds. Four existing destruction technologies were considered, in addition to direct venting of the waste gas. The possibility of CO_2 capture at the Project and either usage or storage was also considered.

5.2.5 Fugitives

Fugitive emissions of CH_4 or CO_2 (from the acid gas stream) are inadvertent releases to the atmosphere from equipment. These primarily occur at connection points in piping or at equipment such as valves. Fugitive emissions from individual leaks can cumulatively be a significant source of emissions; two existing technologies that may reduce emissions from equipment have been considered.

When storing LNG in tanks or loading LNG onto an LNGC, some of the LNG will return to the gas phase. Both the flaring of natural gas vapours or the capture, compression, and either flaring or re-liquefaction of this gas is considered in this assessment.

5.2.6 Disposal of Natural Gas During Maintenance, Upset, or Emergencies

Substantive natural gas releases pose health and safety risks to personnel and the environment. During normal operations, small amounts of natural gas may be released as a result of fugitive emissions. However, during maintenance, upset, or emergencies, substantive volumes of natural gas may require release. Two destruction technologies are considered in this assessment, as well as venting the natural gas.

5.2.7 LNG Carriers in Transit and at Terminal

LNG carriers are designed with storage systems for the safe and efficient transport of LNG during marine transport. The engines of LNGCs are used for transit, maneuvering, and for auxiliary systems aboard the vessel. LNGCs also typically have a boiler to provide heat for personnel. The BAT assessment will look at three energy sources for LNGCs while in transit and while berthed at the terminal.

5.2.8 Tugboats in Transit and at Terminal

Similar to LNGC, tugboats rely on an energy source to transit, maneuver, operate auxiliary systems, and provide heating. The BAT assessment will look at three energy sources while in transit and while berthed at the terminal.

5.2.9 Practices to Reduce Energy Use

There is a direct relationship between energy use and GHG emissions, such that practices that reduce energy use also reduce GHG emissions. Most of the practices listed in Table 5.2–2 are designed to reduce energy use, whether through changes in equipment operation, use monitoring, equipment maintenance, and sizing equipment to the required task.

5.2.10 Practices to Reduce GHG Emissions

Four of the practices listed are designed to reduce the amount of GHG emissions released to the atmosphere. Hydrogen blending is the practice of replacing a portion of natural gas with hydrogen to reduce the amount of carbon that is converted to CO_2. A conventional leak detection and repair program uses special cameras and gas detectors to locate natural gas leaks for subsequent repairs. Newer technologies, including satellites and drones, can also be used for the purpose of leak detection.

5.2.11 Carbon Sinks

Land clearing activities typically include the removal of living and non-living biomass and carbon--containing soils using heavy construction equipment. The extent of the clearing and the fate of the material influences the amount of GHG emissions released. Five practices are included in the assessment with respect to construction and one is included with respect to decommissioning.

5.3 TECHNICAL FEASIBILITY ASSESSMENT

5.3.1 Construction and Decommissioning

5.3.1.1 On-land Equipment

Diesel

Construction equipment that is commercially available in Canada are fueled with diesel derived from crude oil. 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 diesel fuel 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 fueling technologies are well defined in Canada. Diesel trucks sold for use in Canada are designed to meet health and safety, fire and life safety, and air pollution control requirements in Canada.

There would be very low capital and operational risk associated with the use of diesel-fueled equipment.

The use of diesel fuel in on-land construction equipment during the construction phase is technically feasible. Because the Canadian government proposed in 2021 that the sale of light-duty vehicles with internal combustion will be restricted after 2035, it is possible that diesel, biodiesel, and renewable diesel will not be available during decommissioning for light-duty vehicles. However, nothing has been stated regarding heavy duty vehicles. Therefore, it is assumed that diesel remains commercially available and manufactured construction equipment will still use diesel once decommissioning begins.

Biodiesel Blend

British Columbia first legislated the Low Carbon Fuel Standard in 2010. This mandates that 4% of diesel sold in British Columbia must be renewable. The B5 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 elsewhere. Biodiesel is commonly used across Canada, although it is typically only found at a 2% blend in other provinces.

Amendments to the Low Carbon Fuel Standard expands the requirements for diesel sold in British Columbia, such that, by 2030, the GHG emissions intensity for diesel must reach 20% reduction (Government of British Columbia nd).

Biodiesel is temperature sensitive; at low temperatures, biodiesel can form crystals that can plug the fuel filter. This is like petroleum-based diesel; however, the temperature at which crystals form in biodiesel is higher than for petroleum-based diesel. Using a low biodiesel blend (5%) can alleviate this issue.

Construction equipment that operates 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, the Proponents assume for this assessment that biodiesel blends will not be commercially available when decommissioning begins.

Renewable Diesel

British Columbia mandates that 4% of diesel sold in British Columbia must be renewable. Renewable diesel, also referred to as hydrogenation-derived renewable diesel, is produced from the same feedstocks as biodiesel through a process involving hydrotreating, isomerization, and fractionation. Hydrotreating uses hydrogen and high temperature and pressures to convert the oils in the feedstock to simple paraffins (Digital Refining 2010). Isomerization results in the specific chemicals required and fractionation results in the finished product. This equipment is commonly found at traditional oil refineries. Chemically, renewable diesel is the same as petroleum-derived diesel, has a better emissions profile, and has better low temperature operability (Valero 2022). Renewable diesel does not need to be blended with petroleum diesel; it can be used directly with existing engines and infrastructure (Valero 2022).

Renewable diesel first came on the Canadian market in 2019 and was originally available in Vanderhoof and Quesnel, British Columbia (Federated Co-operatives Limited 2019). However, renewable diesel is not currently manufactured in sufficient quantifies for large scale use in Canada. It is produced at locations in the United States, including Louisiana, Washington, and California, with an estimated 1.92 billion gallons per year (Cheers Interactive (India) Private Limited 2022; Pratt 2022a). In August 2022, Canadian canola has been approved as a feedstock for renewable diesel and biodiesel in the United States (Pratt 2022a).

The IEA predicted that the global demand for renewable diesel is expected to triple between 2021 and 2026 (IEA 2021b). The leading driver of this demand are government policies, particularly in the United States and Europe.

Plans for Canadian production of renewable diesel have been announced by several major hydrocarbon producers, including:

- Tidewater Renewables is building a 3,000 barrel per day renewable diesel facility at its Prince George refinery in British Columbia. The new facility is planned to be operational in 2023 (Tidewater Renewables 2021).

- Imperial Oil is planning to build a 20,000 barrels per day renewable diesel facility at the existing Strathcona Refinery in Alberta (Morgan 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.
- Federated Co-operatives Ltd. Announced a new renewable diesel fuel and canola-crushing plant is planned for Regina and will be producing approximately 15,000 barrels per day of renewable diesel starting in 2027 (Djuric 2021).

Based on the increased renewable diesel manufacturing capability and considering the Project's estimated construction time period of 2025 to 2028, the Proponents believe that renewable diesel is technically feasible during the construction period. Renewable diesel is likely to continue to be available during the decommissioning phase.

Gasoline

Gasoline is a liquid hydrocarbon that is less energy dense than diesel and tends to be used in light duty applications. Light duty gasoline vehicles, such as pick-up trucks, are readily available for use during construction. Due to the remoteness of the Project, a gasoline storage and dispensing system on-Site would be required. Gasoline would be delivered by barge periodically.

Gasoline fueled equipment is technically feasible during construction and may be technically feasible during decommissioning.

Electric (battery)

Rather than using fossil fuel combustion to power vehicles, electric-drive vehicles use batteries to store and provide energy. The electricity used to charge batteries could come from on-Site operation or a connection to an electrical grid. While the use of electric batteries would not release GHG emissions, the equipment used to generate the electricity results in GHG emissions. Because there will not be a connection to the BC Hydro electrical grid during construction, if electric equipment is used, the electricity must be generated on-Site, possibly using a diesel generator set.

The use of lithium-ion batteries to store electricity is well established for smaller electronics, such as laptops or cell phones.

As of June 2021, Volvo has a 27 horsepower (**hp**) electric excavator (ECR25) and a 54 hp electric wheel loader (L25) commercially available (Volvo 2022). However, both models are very small in terms of available hp. 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 276 hp to 385 hp. Although Volvo is developing other electric (Gallant 2021) equipment in the size range required for the Project, there is no timeline for availability.

Based on this information, the Proponents believe that suitable 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.

CNG

CNG vehicles have been available for a number of years in light duty and heavy duty on-road applications. With respect to light duty vehicles that may be used to transport materials or personnel on-Site, CNG vehicles are readily available in Canada. For heavy duty (also referred to as severe service), vehicles such as tractors, buses, and garbage trucks have successfully used CNG systems.

CNG vehicles are refueled at a station similar to gasoline or diesel vehicles. However, these stations need access to a natural gas pipeline and equipment to compress and dispense the CNG. Such equipment is technically feasible; however, the natural gas pipeline access for Ksi Lisims is not likely to be completed at an early enough stage for construction to make CNG vehicles a viable option. Although there are no current plans to include a CNG station at the Project, it is technically possible that such a station may be implemented during the lifetime of the Project and used for decommissioning activities.

LNG

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 2019).

There are dual-fuel LNG/diesel conversion kits for certain heavy-duty mining trucks commercially available currently (Gleeson 2020, Latimer 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.

As noted for CNG, the availability of LNG during construction is not anticipated, but may be available at decommissioning.

Based on this information, it is expected that LNG fuel in construction equipment will not 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.

Hydrogen-based Electric

Hydrogen fuel cell technology is relatively new. The fuel cell generates electricity through the chemical reaction between hydrogen and oxygen. Provided that there is a zero-carbon source of hydrogen, no GHGs are released from the use of a hydrogen fuel cell; water is the only by-product. Like an electric battery in a vehicle, a hydrogen fuel cell remains in the equipment and is refueled similar to gasoline or diesel.

Hydrogen fuel cells are already in use in approximately 11,000 cars and in over 20,000 forklifts globally (IEA 2019). 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 kilowatt (**kW**, 248 hp) and is commercially ready for deployment in buses, trucks, and light rail applications (Government of Canada 2019).

The province of British Columbia, through the Go Electric Program, is taking measures to increase the uptake of zero emission vehicles, including hydrogen fuel cell vehicles by building up the hydrogen fueling network (Government of British Columbia 2022). Although currently clustered in the Greater Vancouver Area, British Columbia is committed to building 10 additional hydrogen-fueling stations throughout the province (Government of British Columbia 2022). The scope 2 and third party emissions associated with the production, transportation, and distribution of hydrogen in such facilities has not been evaluated.

With regards to hydrogen used in construction equipment, there are no commercially available construction equipment currently in the market. 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 Nexofuel cells but offering double the power output, higher durability, and less cost (Goodwin 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 GHG intensive, responsible for approximately 830 million tonnes of CO_2 per year. The source of the energy used to produce hydrogen dictates how decarbonized the hydrogen value chain 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 CH_4), 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 feasible 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 become a technically feasible fuel during construction. The use of hydrogen fuel cells in equipment may be technically feasible during decommissioning.

5.3.1.2 Marine Equipment

Marine Fuel

During construction and decommissioning, tugboats and coastal ferries are expected to be used for the transport of personnel and material. Marine diesel and marine gas engines are commonly used in marine vessels and are technically feasible to implement in the construction phase. There is currently no proposed legislation that would prevent marine diesel and marine gas engines from being used in the decommissioning phase. It has been assumed that marine equipment that use these fuels remain technically feasible for the decommissioning phase.

Dual fuel Diesel/LNG Tugboats

Robert Allan Ltd. Is one marine architect that has designed dual fuel diesel/LNG escort tugboats (e.g., Rastar 4000 DF and Rastar 3800 DF). The first Rastar 3800 DF tugboat launched in 2019 and operated in the Ningbo Port in China (Robert Allan Ltd. 2019). The first three Rastar 4000 DF launched in 2017 for operation at Statoil's Melkøya LNG Gas terminal, located in northern Norway (Robert Allan Ltd. 2017).

The HaiSea Marine Limited Partnership (HaiSea Marine) has signed with the manufacturer Sanmar to produce three dual fuel Rastar 4000 DF escort tugboats for operation with the LNG Canada project located in Kitimat, BC (Sanmar A.Ş. 2022).

Dual fuel diesel/LNG tugboats are commercially available and have been in use for approximately five years. Therefore, these tugboats are considered technically feasible during construction and are expected to remain technically feasible during decommissioning.

Electric (battery) Tugboats

Fully electric tugboats are a relatively new technology. The first all-electric tugboat, called *Gisas Power*, was designed by Navtek Naval Technologies and is operated in the Istanbul harbour. Another electric tugboat that was launched in 2022 is the *Sparky*, from the manufacturer Damen; the *Sparky* operates in the port of Auckland (Australia). The manufacturer Sanmar is building two electric-power tugboats of the ElectRA 2800 class for the LNG Canada project. These tugboats are for harbour service and will have dedicated charging stations at their home berths.

Electric tugboats are commercially available but only two are currently in operation globally. By the time Project construction commences, it is likely that only a small number of other electric tugboats will be built.

Although the tugboats are technically feasible, the Project will not have a means to connect tugboats to an electric source during construction. Therefore, electric tugboats are deemed not technically feasible during construction. At the decommissioning phase, such infrastructure could be in place to support decommissioning activities, and therefore, electric tugboats are anticipated to be technically feasible during decommissioning.

Ammonia

Ammonia is a carbon-free combustion fuel; however, it has many challenges that currently prevent it from wide application (Global Maritime Forum 2022). Beyond accessibility, the key challenge for use in marine applications is that ammonia is a health risk for both humans and aquatic life, and would require strict safety standards, measures, and training. Engines designed for the combustion of ammonia are being developed and are expected to be available as early as 2024. However, pilot and demonstration projects will be needed before ammonia becomes readily available as a marine fuel.

Currently, ammonia is commercially produced from natural gas, which results in higher emissions upstream of the fuel than if natural gas was combusted itself. “Green” ammonia can be produced from “green” hydrogen using the Haber-Bosch process, which substantively reduces the carbon intensity of the ammonia.

Ammonia is not considered to be technically feasible during the construction phase. Provided that its challenges are sufficiently addressed and a source of ammonia is available near the Project during decommissioning, ammonia fueled marine equipment may be technically feasible during decommissioning.

Hydrogen

The first hydrogen-fueled tugboat, called the *Hydrotug*, was launched in May 2022 (Blenkey 2022). It has two dual-fuel BeH$_2$ydro engines, each rated for 2 megawatt (**MW**), that burn 85% hydrogen and 25% diesel. When fully operational, the *Hydrotug* will serve the Port of Antwerp-Bruges. An engine that uses 100% hydrogen in a spark ignition system is also available from BeH$_2$ydro (BeH$_2$ydro nd).

Although additional hydrogen-fueled tugboats are expected to be developed, the infrastructure and hydrogen source to fuel such tugboats during construction is not expected to be in place. As such, hydrogen-fueled tugboats are not technically feasible during construction. Assuming that a supply of hydrogen is available near the Project during decommissioning and that this technology continues to mature, hydrogen-fueled tugboats may be technically feasible during decommissioning.

Hybrid Diesel and Electric Ferries

British Columbia has a well-developed coastal ferry system that is operated by BC Ferries. This organization has a history of proactive GHG emission reduction measures, including the installation of shore-based power at select terminals in 2015–2016, use of natural gas engines in select ferries starting in 2016–2017, and retrofit of select ferries to operate on LNG in 2018-2019. Most recently, in 2020, BC Ferries begin operating two hybrid diesel/electric ferries and has added four additional hybrid diesel/electric ferries and an LNG-fueled ferry in 2021 (BC Ferries 2022).

For the Project, it is likely that an independent ferry operator would be contracted. Based on the level of technology maturity and uptake shown by BC Ferries, hybrid diesel/electric ferries are technically feasible during the construction phase of the Project. During decommissioning, the Proponents assume that hybrid fuel diesel/electric ferries will remain technically feasible.

5.3.2 Operation

5.3.2.1 Primary Energy Source

Electricity generation is well established throughout the world. There are many energy sources and technologies available to generate electricity. The established and emerging technologies are discussed in the subsections below.

Connection to the BC Electricity Grid

The BC electricity grid is one of the least GHG intensive grids in Canada, due to the presence of abundant hydroelectric energy. Electricity can be readily generated at hydroelectric and other facilities and then provided to facilities via above-ground or below-ground transmission lines. The Project has received confirmation from BC Hydro that there is sufficient capacity to supply electricity to the Project.

As the Project is situated in an area that does not have existing electrical infrastructure, a transmission line is required to be built and operated with the necessary transmission capacity for the Project. As described in the Application, such a transmission line is the responsibility of a third party and is not part of the Project's Application.

Once the transmission line is ready for use, the Project can operate using electricity from the BC Hydro grid throughout its lifetime. In the event of an outage, a back-up/emergency energy source is required.

A connection to the electrical grid is technically feasible but there is some risk in that completion of a third-party transmission line is required to operate the Project.

On-Site Self Generation

Self-generation of electricity at the Project using gas-fired turbines would require the construction of a power generation facility that would be located either terrestrially, on a self-contained floating barge, or integrated into the FLNG facility. Fuel supply for the power facility would be taken from the incoming natural gas. This option would generate air contaminants and GHG emissions from the combustion of natural gas. Gas-fired turbines are mature technologies that pose very little risk to implementation. Both are considered technically feasible to implement at the start of the Project.

Steam Turbine with Biomass Combustion

Biomass combustion in a boiler 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**) setup. In addition to biomass, a large amount of processed water is required for this operation.

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.

Wind Energy

Wind power is generated from the rotation of a turbine's rotors by the wind to spin a generator. 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 2.8 MW turbine can be up to 132 m (GE Renewable Energy 2022).

As of December 2021, there is 743 MW of installed wind energy capacity in British Columbia. This represents approximately 5% of Canada's installed wind energy capacity (Canadian Renewable Energy Association 2022a).

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 nd]), 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).

When siting wind turbines, the wind resource at the turbine elevation must be considered. Looking at the estimated wind resource over the Project Site as shown by Global Wind Atlas (2022), the mean power density is less than 200 watts per square metre (**W/m^2**) (energy per turbine sweep area) at 100 m in the vicinity of the Project. Approximately 5 km to the southeast, the mean power density ranges from approximately 400 W/m^2 to over 2,000 W/m^2.

Wind power is intermittent and dependent on the wind speed over time at a given location.

Due to the large amount of land area required to install sufficient wind energy equipment, the use of this technology by the Project as the primary energy source is not technically feasible over its lifetime. However, it may be feasible to construct and operate a smaller number of turbines where the wind resource is higher to decrease the amount of energy required from the BC Hydro grid over the Project's 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 is estimated to produce less than 950 kWh/kW/year (Rylan Urban 2018), which is considered low. Therefore, to produce 4,700,000 megawatt-hours (**MWh**) annually to supply the Project, a solar farm with a minimum installed capacity of 4,947 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. As a comparison, the Travers Solar Project, which will be one of Canada's largest solar power installations, will be capable of producing 465 MW of power (Government of Alberta nd). It is currently being constructed on approximately 13 km^2 of land in southern Alberta, with operation expected in late 2022. One of the technological improvements included in the design of this Project is that the solar panels are double-sided, which allows sunlight that reflects off of snow to be captured by the back-side of the panels.

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.

Due to the low level of solar irradiance and the resulting large land area required to install sufficient solar energy equipment, the use of this technology to meet the Project's entire energy needs is not technically feasible. Further study would be needed to determine whether sufficient solar irradiance is present to warrant consideration of solar power to offset electricity use from the BC Hydro electric grid; for the purpose of this assessment, it is assumed that solar power would not be technically feasible at any point in the Project's lifetime.

5.3.2.2 Back-up/Emergency Energy Source

In the event of an interruption in energy supply from the primary energy source, a reliable back-up energy source (either online or from energy storage) is required to enable the safe shutdown of key equipment and protect the health and safety of personnel. For the Project, approximately 10 to 15 MW is needed as a back-up/emergency system.

The most common back-up/emergency energy technology is the diesel generator set. This technology is reliable and mature. In addition, diesel is readily available in British Columbia and can be stored for long periods of time. In the event of an extended outage, diesel can be purchased and delivered to the Project to provide additional generator runtime. Once renewable diesel becomes readily available, it can also be used in the diesel generator set.

A natural gas-driven generator set is also a common, reliable, and mature technology to meet back-up and emergency services needs. Unlike diesel generator sets, however, there is a risk that there is insufficient natural gas packed in the upstream pipeline to run sufficient emergency services at the Project in the event of an extended outage.

Energy storage technologies (e.g., batteries, hydrogen) exist with various levels of implementation in Canada and globally. Such systems have been used as a solution to intermittent energy generation from solar and wind power but can also be used with non-renewable energy generation systems. These systems can be scalable to meet demand, flexible in configuration, and provide benefits to an electrical grid in addition to the electricity user (Canadian Renewable Energy Association 2022b).

Canada's first utility-scale energy storage system was implemented in 2013 by BC Hydro for the community of Field, British Columbia. It used a 1 MW battery energy storage system (NRCan 2018). In a wind power application, the TransAlta WindCharger system uses Tesla Megapacks to store 10 MW (20 MWh) of electricity from the Summerview II wind farm (Colthorpe 2020). A large-scale battery energy storage of 7 MW (40 MWh) is currently being constructed by Yukon Energy in Whitehorse to help meet winter peak demand by charging the batteries during off-peak hours (Colthorpe 2021). This system is planned to be operational in spring 2023.

In all cases of battery energy storage, the length of time that a battery can provide electricity at the rate required is a limiting factor. Because the Project requires up to 15 MW as backup, a battery storage system rated for 40 MWh would only provide sufficient electricity for approximately 2.5 hours. This is not sufficient for the safety of the personnel working at the Project Site and, therefore, a battery system of the size required for the Project is not currently technically feasible.

Hydrogen-based energy storage systems involve using electricity to convert water to hydrogen through electrolysis. The hydrogen is stored typically in a chemical energy carrier. When energy is needed, the hydrogen can be converted back to electricity using a fuel cell. However, similar to energy storage in a battery, there is a limit on the number of hours that such a system would provide electricity. The current small scale of the technology is not sufficient for the Project and, therefore, a hydrogen system of the size required for the Project is not currently technically feasible.

A diesel or renewable diesel generator system is considered technically feasible throughout operation. A natural gas generator system is considered technically feasible; however, further study by the Proponent is needed before this technology can be considered BAT.

5.3.2.3 Waste Gas Containing CO_2

Prior to the liquefaction of natural gas, contaminants such as hydrogen sulphide and CO_2 must be removed to prevent freezing and damage to downstream liquefaction equipment. This is accomplished through an acid gas removal unit, which produces a waste gas stream that is mainly composed of CO_2 and a small amount of hydrogen sulphide and hydrocarbons. Oxidation of the hydrogen sulphide to sulphur dioxide is done to reduce the risk to health and safety related to the hydrogen sulphide. CO_2 present in the waste gas is released to the atmosphere. The Proponents considered two destruction technologies: a thermal oxidizer and a flare. In addition, carbon capture prior to the destruction equipment was considered.

A thermal oxidizer can incinerate the waste gas stream and can control the combustion temperature for complete oxidation of hydrocarbons and sulphur compounds. In addition, there is no visible flame that can be seen from outside the unit.

A flaring system results in a less efficient combustion (i.e., some hydrocarbons and sulphur compounds are oxidized) and has a visible flame that can be seen from a distance.

Both oxidation technologies are mature and are technically feasible at the start of operation.

With respect to carbon capture, systems that strip CO_2 from waste streams are readily available at a commercial scale and in use at various fossil fuel related facilities around the world. Once a high purity CO_2 stream has been created, the CO_2 may be used or stored, depending on the availability of users and storage locations.

The nearest suitable location for storage would be northeastern British Columbia (approximately 630 km), which has depleted gas pools and deep saline formations suitable for CO_2 storage (Hartling 2008). However, there is currently no CO_2 storage operations occurring in this region. If CO_2 storage were to be included in the Project, transportation to the Fort Nelson area for storage could, theoretically, be achieved via a dedicated CO_2 pipeline system. An injection system would be required to be built.

CCUS could be considered near the inlet of the gas transmission pipeline in northeastern BC. While this is outside the scope of the Project, this is an opportunity that could be undertaken by feed gas suppliers to the Project and could reduce the vented CO_2 emissions from the acid gas removal units at the LNG facility.

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 (Kramer 2022). The injected CO_2 is permanently sequestered in oil reservoirs. The ACTL is a 240 km pipeline that, at full capacity, can transport approximately 14.6 million tonnes of CO_2 emissions per year. As of June 2020, the ACTL is fully operational. Within the first eight months of operation, 1 million tonnes of CO_2 have been sequestered (Enhance Energy 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 (**ACG**). Individual CO_2 producers would be responsible for capturing CO_2 at their facilities, then gathering pipelines would connect the facilities to the ACG. 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, which is planned to transport and store up to 10 million tonnes of CO_2 annually from the Alberta Industrial Heartland (Alberta Carbon Grid 2022), 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. There are plans for more CCUS systems, but such systems are major undertakings that take years to develop. Therefore, a Project-specific CCUS is technically feasible but would take a substantial amount of time to implement (approximately 15 years based on the ACTL project).

5.3.2.4 Fugitives

Fugitive emissions chiefly result from leaks at piping connections or equipment. Because leaks represent a safety hazard, as well as a loss of either feedstock or product, the Proponents seek to minimize fugitive emissions to the extent possible.

At connection points with metal piping, one typical construction approach is to use bolted flanges. The use of flanges results in less construction time as bolting is simpler than welding. However, fugitive emissions can occur at flanges and due to the large number of flanges in industrial facilities, the emissions from small leaks can add up. The use of welded connections instead of bolted flanges for hydrocarbon piping reduces the quantities of leaks.

Valves in gas service can also have leaks past the valve stem. Although such leaks are very small, an industrial facility has many valves, which can result in substantive fugitive emissions. By installing valves that are designed for lower valve stem leak rates, the Project can experience less fugitive emissions from valves.

In the case of natural gas that has been boiled off in the LNG storage tanks or during loading of an LNGC, it is possible to capture the gas and flare it, or to capture the gas, compress it, and return the gas to the process for liquefaction.

The described technologies are mature, are in operation around the world, and are technically feasible over the life of the Project.

5.3.2.5 Disposal of Natural Gas During Maintenance, Upset, or Emergencies

When an upset or emergency occurs, a large volume of natural gas may need to be released suddenly for the protection of the equipment or personnel. Venting of the natural gas to the atmosphere is possible, but is generally not preferred for several reasons:

- Natural gas is flammable in certain concentrations and could ignite
- Carbon monoxide, which is toxic, can form from incomplete combustion of natural gas
- Although natural gas is non-toxic, it can cause suffocation if the gas displaces air

At upstream and midstream oil and gas facilities throughout the world, the natural gas from upsets, emergencies, or maintenance events is typically directed to a flare system with a continuous pilot flame to destroy the natural gas and prevent the potential negative effects from its release. A flare header system can be sized to handle natural gas from high-pressure and low-pressure sources and direct the stream through one flare stack.

In upset, emergency, and maintenance conditions, a thermal oxidizer is not suitable because it cannot handle sudden increases in gas volume nor cryogenic gases. Additionally, the thermal oxidizer is typically connected to very specific streams, and not the pressure-relieving system.

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 not technically feasible. Venting is considered to be technically feasible.

5.3.2.6 LNG Carriers in Transit and at Terminal

The Proponents do not have control over the specific LNG carriers that would be calling at the Project. At the start of the Project lifetime, the Proponents expect that the majority of LNGCs will be of the conventional dual fuel BOG and marine fuel type. Such vessels use BOG or low sulphur marine fuel while transiting and while loading. The Project will require vessels calling at the Site to use BOG when moored.

The largest LNG carriers that may call at the Project are the Q-Flex class, with up to 217,000 m^3 of LNG storage. These vessels were first introduced in 2008 and were designed with slow-speed marine diesel engines that were estimated to consume 40% less energy than traditional steam turbines that use only boil-off gas (Cision 2009). Because of the lower energy requirement, these ships release approximately 30% lower GHG emissions than a similar vessel with steam turbines (Qatargas Operating Company Limited 2022). The boil-off gas that is generated aboard the Q-Flex is sent through a system to be reliquefied and returned to storage. This design is partly due to the fact that more BOG is generated than can be used for propulsion in a ship the size of a Q-Flex (Domić et al. 2022)

Engines that combust petroleum-based fuels are commonplace around the world for marine vessels; there is no technological risk to implementation.

Another option that is available in some ports and with some vessels is shore-based power, also referred to as “cold-ironing”, “alternate marine power”, or “High Voltage Shore Connection systems” (Agarhal 2021). When available and when 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 nd) and older vessels can be retrofitted. However, there is not much demand to perform such retrofits for two reasons:

- Ports where LNGCs 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

It is technically feasible that, in the future, LNGCs will be designed to accept shore-based power, however, because the FLNGs are being designed now for vessels that do not accept shore-based power, shore-based power will not be carried forward. For this assessment, LNGCs that use BOG and low sulphur marine fuel will continue to be used throughout the Project lifetime.

5.3.2.7 Tugboats in Transit and at Terminal

Dual fuel Diesel/LNG

Dual fuel diesel/LNG tugboats were described in Section 5.3.1.2. The dual fuel diesel/LNG tugboats are anticipated to remain technically feasible throughout the Project operation.

Electric (battery)

Electric tugboats were described in Section 5.3.1.2. The infrastructure required to supply electricity to the tugboat is not planned for the Project at the start of operation. However, such infrastructure is technically feasible; therefore, electric tugboats are technically feasible later in Project operation and will be further assessed over time.

5.3.3 Practices

The practices that reduce energy use, such as through equipment maintenance, are well established at work sites and facilities around the world. There are no barriers to implementing these practices.

The practice of hydrogen blending is a possible approach to providing energy at a lower GHG emissions intensity. ATCO, an energy provider in Alberta, is implementing a hydrogen blending project in a subsection of its Fort Saskatchewan natural gas distribution system by the end of 2022 (ATCO 2022). A 5% blend using hydrogen produced through electrolysis and renewable power is the target. In the United States, some natural gas and electric utilities are testing whether hydrogen at higher blends are technically feasible. The Energy Innovation group, however, has concerns that this use of hydrogen is not the most efficient nor economical approach to decarbonization (Baldwin et al. 2022).

With respect to the Project, if the natural gas received as feedstock is blended with hydrogen, it is theoretically possible to use hydrogen blending in fuel users such as the flare pilots or, if used, the temporary power barges. The use of hydrogen blended in the feedstock natural gas would require an additional processing unit to extract a small stream of hydrogen from the incoming natural gas pipeline, because the FLNGs will not have the capability to extract hydrogen from natural gas. The additional processing unit(s) would require a significantly larger physical footprint (terrestrial), additional electricity use, and additional operating personnel and equipment to extract the hydrogen and then re-inject it into the fuel gas system. The largest user of such a blended fuel gas, the power generation barges, would only be in use until the electrical grid is available to supply the Project. Since the Project is electrified, the fuel gas system uses a very modest (~0.5%) portion of the incoming feed gas when operating using electricity from the BC Hydro grid. While it is theoretically possible to a inject small stream of hydrogen into the feed gas in the upstream pipeline and then extract same at the facility, the environmental and other impacts of the facilities necessary to do so would also have to be assessed.

There are no alternate sources of hydrogen in the vicinity of the Project.

LDAR is a well-established requirement for natural gas operations in Canada to reduce the amount of fugitive CH_4 and CO_2 leaks from equipment and piping. Optical gas imaging cameras or hydrocarbon gas detectors can be used by trained personnel to survey facilities and locate leaks. Once located, leaks can be quantified in several ways, such as by using a high flow sampler. The quantification of leaks allows the facility operators to prioritize leaks with higher flowrates.

Alternate approaches to the conventional leak detection technologies include the use of satellites, drones, and mobile sensor systems. These approaches provide a wide-area look for fugitive emissions.

With respect to land clearing, there are no technical barriers to the practices indicated.

Regular measurement of the carbon content of hydrocarbon fuels being consumed can lead to the most accurate quantification of CO_2 emissions, which is required for GHG compliance reporting. This practice is well established in the oil and gas industry.

5.3.4 Technical Feasibility Summary

The BAT/BEP that was considered technically feasible in the above section and that will be carried forward are shown in Table 5.3–1.

Table 5.3–1 Results of Technical Feasibility Assessment

Phase/Year	Source	Technologies	Practices
Construction	Carbon sinks	• None	• Biomass burning • Biomass chipping and spreading • Storage and decomposition • Merchantable timber recovery
	On-land equipment (off-road and on-road)	• Diesel fueled • Biodiesel fueled • Renewable diesel • Gasoline fueled	• Anti-idling policy • Optimal sizing • Regular maintenance • Fuel consumption monitoring
	Marine equipment	• Marine diesel fueled • Dual fuel diesel/LNG fueled • Hybrid diesel/electric	• Optimal sizing • Regular maintenance • Fuel or electricity consumption monitoring • Energy efficiency measures

Table 5.3–1 Results of Technical Feasibility Assessment

Phase/Year	Source	Technologies	Practices
Operations	Primary energy source (electricity)	• Connection to BC electricity grid • On-Site gas turbine generation	• Energy efficiency measures • Regular maintenance of equipment (on-Site only) • Measurement of electricity consumption • Hydrogen blending • Monitoring carbon content of hydrocarbon fuels
	Back-up/emergency energy source	• Diesel or renewable diesel generators	• Energy efficiency measures • Regular maintenance of equipment • Measurement of electricity consumption • Hydrogen blending
	Waste gas containing CO_2	• Thermal oxidizer with natural gas combustion to support • Flare with natural gas combustion to support • CCUS prior to destruction equipment	• Optimal sizing • Fuel monitoring • Regular maintenance • Energy efficiency measures
	Fugitives	• Reduction of flanges and other emission points in hydrocarbon piping by using welded connections • Specially designed valves that have lower leak rate from stems • Capture, compression, and re-liquefaction of boil-off gas • Flaring of boil-off gas	• LDAR program using surveys • Use of satellites, drones, or mobile sensors to monitor and identify leaks
	Disposal of natural gas during maintenance, upset, or emergencies	• Flaring • Venting	• None
	LNG carriers in transit	• Dual fuel: boil-off gas and marine diesel • Marine diesel	• None
	LNG carriers at terminal	• Boil-off gas • Marine diesel	• None
	Tugboats in transit	• Dual fuel diesel/LNG	• None
	Tugboats at terminal	• Dual fuel diesel/LNG	• None

Table 5.3–1 Results of Technical Feasibility Assessment

Phase/Year	Source	Technologies	Practices
Decommissioning	On-land equipment	• Diesel fueled • Renewable diesel • Gasoline fueled • Electric (battery) • CNG fueled • LNG fueled • Hydrogen (battery)	• Anti-idling policy • Optimal sizing • Regular maintenance • Fuel consumption monitoring
	Marine equipment	• Marine diesel fueled • Dual fuel diesel/LNG fueled • Hybrid diesel/electric • Electric (battery) • Ammonia fueled • Hydrogen (battery)	• Anti-idling policy • Optimal sizing • Regular maintenance • Fuel consumption monitoring • Energy efficiency measures

5.4 GHG REDUCTION POTENTIAL

The GHG reduction potential for each assessed technology is estimated against a baseline “business as usual” case, which typically represents the current use of fossil fuels.

5.4.1 Construction and Decommissioning

5.4.1.1 On-land Equipment

The “business as usual” case during the construction phase is the use of diesel or gasoline derived from crude oil. The alternate fuels considered in this assessment rely on at least a portion of the fuel being derived from a biogenic source. 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 CH_4 and nitrous oxide (**N_2O**) emissions from biogenic combustion are reportable. The GHG emissions from on-land equipment combusting diesel during construction were estimated to be approximately 40,438 tonnes CO_2e over the construction period; details can be found in the GHG Emissions TDR (Appendix 8A).

Two biogenic replacement options are considered: biodiesel (at 5% biogenic content) and renewable diesel (at 100% biogenic content). By replacing 5% of the diesel with biodiesel and calculating emissions using the same methodology, the GHG emissions from the biodiesel blend would be 38,738 t CO_2e (4% reduction). Similarly, by replacing 100% of the diesel with renewable diesel, the GHG emissions from the renewable diesel would be 1,782 t CO_2e (96% reduction). Therefore, the potential emissions reductions could be approximately 1,700 tonnes CO_2e over the construction period if using biodiesel and approximately 38,656 t CO_2e if using renewable diesel over the construction period.

The likely liquid energy sources available during decommissioning are diesel, renewable diesel, CNG, 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 (40,438 t CO_2e). Assuming that ECCC's approach of not including CO_2 from biogenic emissions remains in place, the use of renewable diesel provides the greatest reduction in GHG emissions. Similar to the construction phase, decommissioning emissions are likely to be similar to 1,700 t CO_2e (96% reduction). If CNG or LNG was used 100% of the time for decommissioning activities, the estimated emissions would be approximately 24,635 t CO_2e, when using higher heating values for diesel and natural gas from United States Environmental Protection Agency (**US EPA**) (1995) and emission factors from the ECCC NIR (ECCC 2023). Note that this estimate does not take the differences in equipment efficiency into account; diesel engines tend to be less efficient that gas-based engines, so the estimates presented are conservatively high. The reduction achieved by CNG or LNG could be approximately 15,804 t CO_2e/y (39% reduction).

The associated GHG emissions with respect to electric battery use during decommissioning are expected to be similar to equipment using renewable diesel. There would be no GHG emissions directly emitted from the use of hydrogen-fueled equipment.

5.4.1.2 Marine Equipment

Considering marine diesel as the "business as usual" case, an estimated 3,890 t CO_2e are anticipated to be released over the construction period from the use of tugboats and ferries. The use of dual fuel diesel/LNG or electricity for tugboats and ferries during construction would result in emission reductions. Without considering changes in efficiency (i.e., a need for less or more fuel based on the fuel type and technology), if the total amount of diesel used during construction were instead LNG, the resulting GHG emissions would be approximately 2,735 t CO_2e, which is a reduction of 1,155 t CO_2e (30% reduction). Similarly, if diesel was replaced with electricity at the current level of efficiency, the resulting GHG emissions would be approximately 171 t CO_2e, which is a reduction of 3,719 t CO_2e (96% reduction).

GHG emissions from marine vessels during decommissioning are expected to be similar to those for construction, between 171 t CO_2e and 3,719 t CO_2e from the use of LNG and electric vessels.

5.4.1.3 Carbon Sinks

Depending on the practice(s) used to manage biomass and soils, CO_2 or CH_4 can be released either quickly (within construction phase) or slowly (over approximately 20 years or more). In general, recovery of merchantable timber provides the longest timeframe for preventing the associated carbon from entering the atmosphere and biomass burning provides the shortest timeframe. Activities that promote decomposition generally occur over approximately 20 years, with most carbon being converted to CO_2, CH_4, and N_2O shortly after disturbance. Biomass burning will release CO_2, CH_4, and N_2O during the construction period (immediately upon burning). There is potential for increased CH_4 generation from stockpiling and decomposition. The practices that would result in the least GHG emissions are recovery of merchantable timber and chipping and spreading.

5.4.2 Operation

5.4.2.1 Primary Energy Source

Electricity generation in British Columbia is 94% from hydrogeneration, 3% from wind and solar power, and 3% from fuel combustion (ECCC 2023). As a result of this focus on renewable generation, the GHG emissions intensity of electricity generated in British Columbia is one of the lowest in Canada (14 grams CO_2e/kWh in 2021, ECCC 2023). Only electricity generation in Manitoba and Quebec have lower GHG emissions intensity. BC Hydro estimates the grid intensity annually to account for both electricity generated in BC and imported; the 2022 average was 11.5 t CO_2e per gigawatt-hour (**GWh**) (Government of British Columbia nd). Since the Project will be connected to the BC Hydro electrical grid, the average GHG emissions from electricity use would be 28,645 t CO_2e annually.

In the Alternative Case that the connection to the BC Hydro grid is delayed prior to startup, the Project intends to self-generate electricity using on-Site gas fired generators mounted on floating barges. The estimated GHG emissions associated with a combined cycle gas turbine system capable of supporting the Project are 1,644,002 t CO_2e annually.

A comparable simple cycle gas turbine system capable of supplying the Project would release approximately 2,279,785 t CO_2e per year, assuming an energy efficiency of 38%.

By connecting to the BC Hydro electrical grid instead of self-generating electricity (either simple or combined cycle), a GHG emission reduction of 98% can be realized.

5.4.2.2 Back-up/Emergency Energy Source

A diesel generator set (or sets) is the only technically feasible technology and also represents the “Business as Usual” Case. Therefore, there are no reductions in GHG emissions from the use of this technology.

5.4.2.3 Waste Gas Containing CO_2

Because the waste gas stream contains very little hydrocarbons, there is very little difference in GHG emissions from a thermal oxidizer and a flare. The greatest opportunity for GHG reduction is for the CO_2 in the waste gas stream to be captured prior to the oxidation technology, whether at the gas transmission pipeline inlet or at the Project. With a capture efficiency of 90%, a carbon capture system could prevent approximately 91,431 t CO_2 reaching the atmosphere each year. However, as described in the Technical Feasibility section, this system would likely not be in place for at least 15 years after operation commences, which reduces the total amount of CO_2 that could be sequestered over the life of the Project.

5.4.2.4 Fugitives

Although it is known that the use of welded connections and reduced leak valve stems would reduce GHG emissions, the specific quantities of GHGs reduced cannot be estimated at the time of writing. The use of a boil-off gas system to recover and reintroduce the natural gas into the system will result in lower GHG emissions than if the gas was flared.

5.4.2.5 Disposal of Natural Gas During Maintenance, Upset, or Emergencies

The largest upset event that the Project may experience involves a release of approximately 193,000 m^3 of natural gas. The amount of CH_4 that would be released to the atmosphere from this upset would be approximately 1,448 t CO_2e. A flare system can oxidize the CH_4 to CO_2 at 98% efficiency, such that approximately 381 t CO_2e is released. This is a reduction of approximately 1,067 t CO_2e or 74%. Therefore, flaring of the gas from maintenance, upset, or emergency conditions would result in lower GHG emissions than if the gas was vented.

5.4.2.6 LNG Carriers in Transit and at Terminal

The majority of LNGCs that are anticipated to call at the Project are required to use LNG for fuel. The International Maritime Organization (**IMO**) adopted a revised strategy to reduce greenhouse gas emissions from international shipping in July of 2023. The revised IMO GHG Strategy included enhanced common ambition to reach net-zero emissions from international shipping close to 2050, a commitment to ensure an uptake of alternative zero and near-zero GHG fuels by 2030 (5–10% of energy used) as well as indicative checkpoints for 2030 (20–30% reduction from 2008) and 2040 (70–80% from 2008). With the IMO GHG strategy underway, GHG emissions from LNGC are expected to decrease over the life of the Project (IMO 2023).

While at the terminal, LNGCs that combust LNG release approximately 7,151 t CO_2e annually. For comparison, if these LNGCs combusted marine diesel the GHG emissions would be approximately 25,227 t CO_2e. Therefore, the combustion of LNG at the terminal results in a 72% reduction in GHG emissions.

For assessment purposes, GHG emissions associated with the LNGCs while in the Portland Inlet were estimated assuming that the LNGCs combust marine fuel. There are no emission reductions associated with using marine fuel. A reduction of approximately 72% may be achieved if LNG was used instead of marine fuel.

5.4.2.7 Tugboats in Transit and at Terminal

Tugboats that use LNG instead of diesel release fewer GHG emissions than those using diesel only. This is because LNG has less carbon intensity than diesel, even when accounting for the change in energy density. The tugboats that accompany LNGCs in the Portland Inlet would release approximately 1,466 t CO_2e annually if the tugboats burned LNG instead of marine fuel; this is a reduction of approximately 31%. Similarly, a reduction of 34% may be achieved if using LNG instead of marine fuel while tugboats are accompanying an LNGC at the terminal.

Tugboats that exclusively use electricity would result in no direct GHG emissions but would have indirect (acquired energy) emissions. Because of the low GHG emissions intensity of the BC Hydro electrical grid, emissions reductions of approximately 98% may be achieved for both tugboats in transit and at the terminal.

5.5 ECONOMIC FEASIBILITY

5.5.1 Construction and Decommissioning

5.5.1.1 On-land Equipment

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

At the time of writing, biodiesel is readily available in British Columbia at approximately CA$2.29 per litre (NRCan 2022). This price includes British Columbia's current carbon tax rate of $50 per tonne of CO_2e (generated from diesel combustion). 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 CO_2e (Government of Canada 2021).

The cost of diesel is expected to rise over the Project lifetime.

The cost of diesel, renewable diesel, electricity, CNG, LNG, and hydrogen once decommissioning begins cannot be determined at this stage, as many factors, such as demand, supply, and regulations affect the prices. Prior to decommissioning, the Proponents and the construction contractor(s) would assess the economics of using each energy type, including capital and operating costs.

5.5.1.2 Marine Equipment

At the time of writing, the British Columbia Low Carbon Fuel Standard does not apply to fuels used for marine purposes. However, it is anticipated that these fuels will be subject to emission reduction measures that cause increases in price in the future.

The use of ammonia and hydrogen during decommissioning would require substantive investment in bunkering and storage infrastructure at the Project for work that occurs over a relatively short period of time. Ammonia can be toxic to humans, and any accidental release of large amounts of ammonia vapor (or liquid, which readily vaporizes) could result in health impacts. Ammonia is water soluble, and a release into the water could have impacts on fish and wildlife. Financially, installing such equipment to support decommissioning activities is not financially viable without support. Additionally, such infrastructure would need to be removed as part of decommissioning the facility, which may make these fuels unavailable during late stages of the work.

Because the transmission line is expected to remain operational during decommissioning, electric battery-operated marine equipment remains a viable option. The capital and operating costs of such equipment are not known at this time.

5.5.1.3 Carbon Sinks

The costs to manage biomass and soils are relatively low compared to other aspects of construction. Of the identified practices, recovery of merchantable timber is likely to have the highest cost but could result in a profit if the timber is sold rather than donated. Chipping and spreading of biomass requires equipment and labour costs that are higher than those for biomass burning due to the remote location. Biomass burning is more economically feasible than chipping and spreading. The cost of stockpiling biomass is also economically feasible.

Site remediation during decommissioning is a requirement of the Proponent's lease with the Nisg̱a'a Nation.

5.5.2 Operation

5.5.2.1 Primary and Back-up/Emergency Energy Sources

A back-up/emergency diesel generator system of the size needed for the Project does not represent a financial barrier to the Project.

Semiannual sampling and analysis of hydrocarbon fuels for carbon content does not represent a financial barrier to the Project.

5.5.2.2 Carbon Capture and Storage

CCUS at the Project Site is not feasible as there are at this time any suitable sequestration locations that have been identified on the west coast of British Columbia. The distance from the Project to the nearest potential storage wells in northeastern BC is approximately 630 km. Detailed costing of a pipeline system to transport and inject the CO_2 to the storage location cannot be performed with the information currently available; however, the cost of implementing the CCUS equipment at the Project Site along with a CO_2 pipeline system to northeastern BC could exceed 10% of the currently anticipated Project costs.

At present, the low CO_2 content of the feed natural gas challenges the economic feasibility of CCUS facilities upstream of the Project. Further, there is currently a lack of well-established CO_2 sequestration infrastructure in northeastern BC. The expected cost savings from sequestering the small amount of CO_2 entrained in the natural gas would be insufficient to economically justify the capital cost of CCUS facilities, even when including the current refundable tax credit that would be received on eligible equipment.

While the low CO_2 content of the feed gas and relatively high cost of CCUS facilities make CCUS uneconomic currently, there are several scenarios in which an upstream CCUS project may become economically feasible in the future:

- Expansion of CO_2 sequestration infrastructure in northeastern BC
- Reduced capital and operating costs associated with CCUS (which is possible, given the ongoing research, development, and optimizations and increasing commercial use of CCUS technologies)
- Increased tax credit associated with CCUS equipment to help recover the capital cost investment (e.g., *US Inflation Reduction Act*)

These scenarios could increase the economic viability of an upstream CCUS project. While this would be outside the scope of the Project, this opportunity will continue to be evaluated by feed gas suppliers or other third parties.

5.5.2.3 Fugitives

LDAR surveys done at ground-level involve personnel looking for and cataloging leaks. Depending on the size of the facility, this can be a time-consuming process. However, repairing leaks decreases costs to the facility from wasted natural gas and GHG compliance. There is no financial barrier to performing on-ground LDAR surveys.

The equipment needed to capture, recompress, and reinject the natural gas vapours from storage or loading activities do not represent a financial barrier for the Project.

Drone or satellite surveys may be more expensive than traditional surveys, but cost is not expected to be a financial barrier for the Project.

5.5.2.4 Disposal of Natural Gas During Maintenance, Upset, or Emergencies

Between a flaring system and allowing natural gas to vent to atmosphere, there is a larger capital and operating cost associated with a flaring system versus a venting system. However, neither represent financial barriers to the Project.

5.5.2.5 LNG Carriers in Transit and at Terminal

The Proponents do not have ownership or control over the specific LNGCs (and hence their power systems) that will call at the Project. However, there is opportunity for the Proponents to include in contracts with LNG buyers conditions or clauses that encourage the use of LNGCs that have high ratings on their energy efficiency and carbon intensity as defined by the IMO (see Section 5.4.2.6). Additionally, the Proponents can require the LNGCs to use boil off gas (rather than marine fuel) to generate power when moored at the terminal.

5.5.2.6 Tugboats in Transit and at Terminal

Details on tugboat contractual arrangements are not available currently. However, it is understood that tugboats that are other than single fuel diesel are more expensive to purchase than tugboats with dual fuel engines. In addition, the electrical infrastructure to support electric tugboats is an additional financial barrier.

5.6 SELECTION OF BAT/BEP

In accordance with the *Technical Guide Related to the Strategic Assessment of Climate Change,* the following section outlines two combinations of the technologies and practices not eliminated in the previous section. These combinations prioritize early emissions reductions and reduction of GHG emissions from the largest emission sources based on technical, economic and social feasibility. Relying on the assessments above, the following emission reduction combinations are considered.

5.6.1 Combination 1

This scenario reflects a realistic uptake of technologies and practices available at the start of construction and operation and is described in Table 5.6–1.

Table 5.6–1 BAT/BEP – Combination 1

Phase/Year	Source	Technologies	Practices
Construction	Carbon Sinks	• None	• Recovery of merchantable timber • Biomass burning • Stockpiling and decomposition
	On-land equipment (off-road and on-road)	• Renewable diesel • Gasoline fueled	• Anti-idling policy • Optimal sizing • Regular maintenance • Fuel consumption monitoring
	Marine equipment	• Marine diesel fueled • Dual fuel diesel/LNG fueled	• Optimal sizing • Regular maintenance • Fuel or electricity consumption monitoring • Energy efficiency measures

Table 5.6–1 BAT/BEP – Combination 1

Phase/Year	Source	Technologies	Practices
Operations	Primary energy source (electricity)	• Connection to BC electricity grid • Temporary gas-fired barges (if grid connection is delayed)	• Energy efficiency measures • Regular maintenance of equipment (on-Site only) • Measurement of electricity consumption • Monitoring carbon content of hydrocarbon fuels
	Back-up/emergency energy source	• Diesel generators	• Energy efficiency measures • Regular maintenance of equipment
	Waste gas containing CO_2	• Thermal oxidizer with natural gas combustion to support	• Optimal sizing • Fuel monitoring • Regular maintenance • Energy efficiency measures
	Fugitives	• Reduction of flanges and other emission points by using welded connections for hydrocarbon piping • Specially designed valves that have lower leak rate from stems • Capture, compression, and re-liquefaction of boil-off gas	• LDAR program using surveys • Use of satellites or drones to identify and monitor leaks
	Disposal of natural gas during maintenance, upset, or emergencies	• Flaring	• None
	LNG carriers in transit	• Dual fuel boil-off gas and marine fuel	• None
	LNG carriers at terminal	• Dual fuel boil-off gas	• None
	Tugboats in transit	• Dual fuel diesel/LNG	• None
	Tugboats at terminal	• Dual fuel diesel/LNG	• None

Table 5.6–1 BAT/BEP – Combination 1

Phase/Year	Source	Technologies	Practices
Decommissioning	On-land equipment	• Renewable diesel • Gasoline fueled • Electric (battery)	• Anti-idling policy • Optimal sizing • Regular maintenance • Fuel consumption monitoring
	Marine equipment	• Dual fuel diesel/LNG fueled	• Anti-idling policy • Optimal sizing • Regular maintenance • Fuel consumption monitoring • Energy efficiency measures
	Carbon Sinks	• None	• Site remediation

5.6.2 Combination 2

This scenario, described in Table 5.6–2, reflects an uptake of technologies and practices that may not be feasible at the start of operation but would result in reduced GHG emissions.

Table 5.6–2 BAT/BEP – Combination 2

Phase/Year	Source	Technologies	Practices
Construction	Carbon sinks	• None	• Recovery of merchantable timber • Biomass burning • Stockpiling and decomposition
	On-land equipment (off-road and on-road)	• Renewable diesel • Gasoline fueled	• Anti-idling policy • Optimal sizing • Regular maintenance • Fuel consumption monitoring
	Marine equipment	• Dual fuel diesel/LNG fueled	• Optimal sizing • Regular maintenance • Fuel or electricity consumption monitoring • Energy efficiency measures

Table 5.6–2 BAT/BEP – Combination 2

Phase/Year	Source	Technologies	Practices
Operations	Primary energy source (electricity)	• Connection to BC electricity grid	• Energy efficiency measures • Regular maintenance of equipment (on-Site only) • Measurement of electricity consumption
	Back-up/emergency energy source	• Diesel generators	• Energy efficiency measures • Regular maintenance of equipment • Measurement of electricity consumption
	Waste gas containing CO_2	• Thermal oxidizer with natural gas combustion to support	• Optimal sizing • Fuel monitoring • Regular maintenance • Energy efficiency measures
	Fugitives	• Reduction of flanges and other emission points by using welded connections • Specially designed valves that have lower leak rate from stems • Capture, compression, and re-liquefaction of boil-off gas	• LDAR program using surveys • Use of satellites or drones to identify and monitor leaks
	Disposal of natural gas during maintenance, upset, or emergencies	• Flaring	• None
	LNG carriers in transit	• Dual fuel boil-off gas and marine fuel	• None
	LNG carriers at terminal	• Boil-off gas	• None
	Tugboats in transit	• Electricity (battery) with fossil fuel back-up	• None
	Tugboats at terminal	• Electricity (battery) with fossil fuel back-up	• None

Table 5.6–2 BAT/BEP – Combination 2

Phase/Year	Source	Technologies	Practices
Decommissioning	On-land equipment	• Renewable diesel • Electric (battery)	• Anti-idling policy • Optimal sizing • Regular maintenance • Fuel consumption monitoring
	Marine equipment	• Electric (battery)	• Anti-idling policy • Optimal sizing • Regular maintenance • Energy efficiency measures
	Carbon sinks	• None	• Site remediation

5.6.3 Selected Emission Reduction Scenario

The scenario that is considered BAT/BEP for this Project is Combination 1. The technologies and practices selected for this scenario reflect best available technologies and practices that can be implemented at the start of the construction, operation, and decommissioning phases. Combination 2 was not selected as certain technologies, while technically feasible and with good GHG reduction potential, are not ready for implementation at the start of each Project phase. A summary of the selected BAT/BEP and reasons why other options were not selected, as well as information on the re-evaluation timeframe, are provided in Table 5.6–3.

Table 5.6–3 Summary of BAT/BEP Assessment

GHG Source	BAT	BEP	Selected Mitigation Technology	Selected Environmental Practice Mitigation	Reason Option Not Selected (as applicable)	Re-evaluation Timeframe for Implementing BAT (as applicable)
Construction						
Carbon Sinks	• N/A	• Biomass burning • Biomass chipping and spreading • Storage and decomposition • Merchantable timber recovery	• N/A	• Recovery of merchantable timber • Biomass burning • Storage and decomposition	• Chipping and spreading during construction would result in emissions as well as adding to the impacted terrestrial footprint. Not considered economically feasible.	• N/A
On-land equipment	• Diesel fueled • Biodiesel fueled • Renewable diesel • Gasoline fueled	• Anti-idling policy • Optimal sizing • Regular maintenance • Fuel consumption monitoring	• Diesel • Gasoline fueled	• BEP (all)	• Sufficient supply of renewable diesel may be a barrier to selected mitigation.	• The availability of Renewable diesel will be re-assessed at time of construction

Table 5.6–3 Summary of BAT/BEP Assessment

GHG Source	BAT	BEP	Selected Mitigation Technology	Selected Environmental Practice Mitigation	Reason Option Not Selected (as applicable)	Re-evaluation Timeframe for Implementing BAT (as applicable)
Marine equipment	• Marine diesel fueled • Dual fuel diesel/LNG fueled • Hybrid diesel/electric	• Optimal sizing • Regular maintenance • Fuel or electricity consumption monitoring • Energy efficiency measures	• Marine diesel fueled	• BEP (all)	• Dual-fuel and hybrid are purpose built and may not be ready in time for construction or available in the region.	• N/A
Operation						
Facility primary energy source	• Connection to BC electricity grid • On-Site Combined Cycle power generation	• Energy efficiency measures • Regular maintenance of equipment (on-Site only) • Measurement of electricity consumption • Hydrogen blending • Monitoring carbon content of hydrocarbon fuels	• Connection to the BC grid for renewable energy • On-Site Combined Cycle power generation (if the grid is not available)	• Energy efficiency measures • Regular maintenance of equipment (on-Site only) • Measurement of electricity consumption • Monitoring carbon content of hydrocarbon fuels	• On-Site power generation, if grid is not available. • Sources of hydrogen for blending is not available at the Site	• N/A

Table 5.6–3 Summary of BAT/BEP Assessment

GHG Source	BAT	BEP	Selected Mitigation Technology	Selected Environmental Practice Mitigation	Reason Option Not Selected (as applicable)	Re-evaluation Timeframe for Implementing BAT (as applicable)
Back-up/ Emergency Energy source	• Diesel or renewable diesel engine generators • Natural gas engine generators	• Energy efficiency measures • Regular maintenance of equipment • Optimal sizing • Hydrogen blending	• Diesel generators	• Energy efficiency measures • Regular maintenance of equipment • Optimal sizin	• Renewable diesel is newly mature and there may not be enough production capacity to source sufficient quantities for the Project. • Natural gas may not be available in the event of a grid power failure that shuts off the incoming gas pipeline. • Sources of hydrogen for blending is not available at the Site	• The availability of Renewable diesel for back-up or emergency power will be reviewed during the 5-year review period of the Net-Zero Plan

Table 5.6–3 Summary of BAT/BEP Assessment

GHG Source	BAT	BEP	Selected Mitigation Technology	Selected Environmental Practice Mitigation	Reason Option Not Selected (as applicable)	Re-evaluation Timeframe for Implementing BAT (as applicable)
Waste gas containing CO_2	• Thermal oxidizer with natural gas combustion to support • Flare with natural gas combustion to support • CCUS prior to destruction equipment	• Optimal sizing • Fuel monitoring • Regular maintenance • Energy efficiency measures	• Thermal oxidizer with natural gas combustion to support	• BEP (all)	• The addition of CCUS prior to destruction equipment was eliminated due primarily to economic feasibility. As discussed, the greatest opportunity for GHG reduction is for the CO_2 in the waste gas stream to be captured prior to the oxidation technology, whether at the gas transmission pipeline inlet or at the Project. • A thermal oxidizer is more efficient at converting hydrocarbons to CO_2 than a flare.	• The option of removing CO_2 from feed gas will be reviewed during the 5-year review period of the Net-Zero Plan

Table 5.6–3 Summary of BAT/BEP Assessment

GHG Source	BAT	BEP	Selected Mitigation Technology	Selected Environmental Practice Mitigation	Reason Option Not Selected (as applicable)	Re-evaluation Timeframe for Implementing BAT (as applicable)
Fugitives	• Reduction of flanges and other emission points in hydrocarbon piping by using welded connections • Specially designed valves that have lower leak rate from stems • Capture, compression, and re-liquefaction of boil-off gas • Flaring of boil-off gas	• LDAR program using surveys • Use of satellites, drones, or mobile sensors to monitor and identify leaks	• Reduction of flanges and other emission points by using welded connections for hydrocarbon piping • Specially designed valves that have lower leak rate from stems • Capture, compression, and re-liquefaction of boil-off gas	• BEP (all)	• Flaring of boil-off gas results in higher emissions than the selected BAT	• Emerging BAT and BEP will be reviewed periodically during Operation over the life of the Project and will be reviewed during the 5-year review period of the Net-Zero plan.
Disposal of natural gas during maintenance, upset, or emergencies	• Flaring • Venting	• None	• Flaring	• N/A	• N/A • Venting releases more GHGs than flaring.	• N/A

Table 5.6–3 Summary of BAT/BEP Assessment

GHG Source	BAT	BEP	Selected Mitigation Technology	Selected Environmental Practice Mitigation	Reason Option Not Selected (as applicable)	Re-evaluation Timeframe for Implementing BAT (as applicable)
LNG carriers in transit	• Dual fuel: boil-off gas and marine diesel • Marine diesel	• None	• BAT (all)	• N/A	• N/A	• N/A
LNG carriers at terminal	• Boil-off gas • Marine diesel	• None	• BAT (all)	• N/A	• N/A	• N/A
Tugboats in transit	• Dual fuel diesel/LNG • Electric	• None	• Dual fuel diesel/LNG	• N/A	• Transit tugboats will not be based at the Site and will not be under control of the Proponents. • Electric tugboats are purpose built and few are in operation. • Transit tugboats require a much larger range than terminal tugboats.	• N/A

Table 5.6–3 Summary of BAT/BEP Assessment

GHG Source	BAT	BEP	Selected Mitigation Technology	Selected Environmental Practice Mitigation	Reason Option Not Selected (as applicable)	Re-evaluation Timeframe for Implementing BAT (as applicable)
Tugboats at terminal	• Dual fuel diesel/LNG • Electric	• None	• Dual fuel diesel/LNG	• N/A	• Electric tugboats are purpose built and few are in operation. • Additional feasibility assessments have yet to be completed to define tug requirements including but not limited to, tug sizing, fuel availability, and redundancy requirements.	• As the Project advances through detailed design and engineering, the feasibility of alternate fuel systems will be assessed.

Table 5.6–3 Summary of BAT/BEP Assessment

GHG Source	BAT	BEP	Selected Mitigation Technology	Selected Environmental Practice Mitigation	Reason Option Not Selected (as applicable)	Re-evaluation Timeframe for Implementing BAT (as applicable)
Decommissioning						
On-land equipment	• Diesel fueled • Renewable diesel • Gasoline fueled • Electric (battery) • CNG fueled • LNG fueled • Hydrogen (battery)	• Anti-idling policy • Optimal sizing • Regular maintenance • Fuel consumption monitoring	• The use of renewable diesel may reduce GHG emissions by 96% over the use of diesel. • BEP will reduce fuel consumption; however, the effect cannot be quantified without detailed information. • Electric (battery)	• BEP (all)	• The Proponents anticipate that alternative fueled construction equipment will be available for the decommissioning phase; however, it is premature to assess the specific types of fuel systems that will be available at the end of Project life.	• The Proponents will review at a more appropriate time to the decommissioning phase of the facility.

Table 5.6–3 Summary of BAT/BEP Assessment

GHG Source	BAT	BEP	Selected Mitigation Technology	Selected Environmental Practice Mitigation	Reason Option Not Selected (as applicable)	Re-evaluation Timeframe for Implementing BAT (as applicable)
Marine equipment	• Marine diesel fueled • Dual fuel diesel/LNG fueled • Hybrid diesel/electric • Electric (battery) • Ammonia fueled • Hydrogen (battery)	• Anti-idling policy • Optimal sizing • Regular maintenance • Fuel consumption monitoring • Energy efficiency measures	• Dual fuel diesel/LNG equipment release fewer GHG emissions than diesel-only equipment (30% reduction). • BEP measures will decrease fuel consumption, resulting in fewer GHG emissions.	• BEP (all)	• The Proponents anticipate that alternative fueled marine equipment will be available for the decommissioning phase; however, it is premature to assess the specific types of fuel systems that will be available at the end of Project life.	• The Proponents will review at a more appropriate time to the decommissioning phase of the facility.

5.6.3.1 Discussion

Information on the GHG reduction potential, level of technology maturity, and barriers to implementation are presented in Table 5.6–3.

5.6.3.2 Eliminated Technologies and Practices

The following technologies and practices were eliminated during the assessment:

- Construction phase:
  - Carbon sinks: chipping and spreading due to GHG emission reductions and economic feasibility
  - On-land equipment: electric (battery), CNG, LNG, hydrogen-based electric due to technical feasibility
  - Marine equipment: electric (battery), ammonia, hydrogen due to technical feasibility
- Operation phase:
  - Primary energy source: on-Site steam turbine with biomass combustion, wind energy, solar energy due to technical feasibility; hydrogen blending due to technical feasibility
  - Back-up energy source: hydrogen blending due to technical feasibility, natural gas generator set due to technical feasibility
  - Waste gas containing CO_2: flare with natural gas combustion to support due to technical feasibility; CCUS due to economic feasibility
  - Fugitives: hydrogen blending due to technical feasibility, flaring due to GHG reduction potential
  - Disposal of natural gas during maintenance, upset, or emergencies: thermal oxidizer due to technical feasibility
  - LNG carriers in transit and at terminal: shore-based electrical system due to technical feasibility
  - Tugboats in transit and at terminal: None
- Decommissioning phase
  - On-land equipment: biodiesel due to technical feasibility

Table 5.6–4 Summary of Selected BAT/BEP

Phase/Year	Source	GHG Reduction Potential	Technology/Practice Maturity	Barriers
Construction	Carbon sinks	• Biomass burning can reduce the amount of carbon that becomes CH_4, which has a higher global warming potential than CO_2. • Opportunity to keep carbon sequestered in merchantable timber.	• Mature	• Financial barrier with respect to identifying, cutting, and transporting merchantable timber.
	On-land equipment	• Renewable diesel can reduce GHG emissions by 96% compared to fossil fuel diesel. • BEP will reduce diesel consumption; however, the effect cannot be quantified without detailed information.	• Mature in United States, developing in Canada	• Access to contractors with newer fleets. • Suitable “park and ride” locations. • Sufficient supply of renewable diesel.
	Marine equipment	• Dual fuel diesel/LNG equipment release fewer GHG emissions than diesel-only equipment (30% reduction). • BEP measures will decrease fuel consumption, resulting in fewer GHG emissions.	• Mature (marine diesel) • Mature (dual fuel diesel and LNG tugboats)	• Marine vessels in the region during the construction period are likely to be of the most mature technology (marine diesel).
Operations	Primary energy (electricity)	• Connection to BC electricity grid will result in a reduction of 98% in GHG emissions compared to a simple cycle gas turbine system. • Detailed design will seek to optimize electricity use at the Project.	• Mature	• Delays due to the electrical power grid could result in the need for temporary power barges.
	Back-up/emergency energy source	• Diesel generators do not provide a GHG reduction. • BEP measures will decrease fuel consumption, resulting in fewer GHG emissions.	• Mature	• No barriers

Table 5.6–4 Summary of Selected BAT/BEP

Phase/Year	Source	GHG Reduction Potential	Technology/Practice Maturity	Barriers
Operations (cont'd)	Waste gas containing CO_2	• The CO_2 is vented to the atmosphere. Recovery of the CO_2 is not possible for economic reasons. • The BEP will decrease the amount of natural gas used as an auxiliary fuel, resulting in fewer GHG emissions.	• Mature	• No barriers
	Fugitives	• The planned BAT and BEP are well established for GHG emission reductions. Estimates of GHG emission reductions are not available.	• Mature	• No barriers
	Disposal of natural gas during maintenance, upset, and emergencies	• Flaring of natural gas during upsets and emergencies is a business-as-usual technology. • During a large upset, approximately 74% less GHGs would be released if the gas was able to be flared rather than vented.	• Mature	• No barriers
	LNG carriers in transit and at terminal	• BAT and BEP use is subject to the particular vessels that call at the Project. • LNGC use of LNG for fuel at terminal results in decreased GHG emissions (72% reduction). • No GHG reduction for using marine fuel while transiting.	• Variable, mostly mature technologies expected	• No barriers

Table 5.6–4 Summary of Selected BAT/BEP

Phase/Year	Source	GHG Reduction Potential	Technology/Practice Maturity	Barriers
	Tugboat in transit and at terminal	• Dual fuel diesel/LNG tugboats release fewer GHG emissions than diesel-only tugboats. • If using LNG, 31% reduction in transit and 34% reduction at terminal. • BEP measures will decrease fuel consumption, resulting in fewer GHG emissions.	• Newly mature (dual fuel and LNG tugboats)	• Vessels will have to be purpose-built to service the Project and will be more expensive than conventional tugboats.
Decommissioning	Carbon sinks	• There will likely be minimal GHG emissions from new land clearing. Once complete, the Project area would be revegetated, thereby increasing carbon sink capacity.	• Mature	• No barriers
	On-land equipment	• The use of renewable diesel may reduce GHG emissions by 96% over the use of diesel. • BEP will reduce fuel consumption; however, the effect cannot be quantified without detailed information.	• Mature	• No barriers
	Marine equipment	• Dual fuel diesel/LNG equipment release fewer GHG emissions than diesel-only equipment (30% reduction). • BEP measures will decrease fuel consumption, resulting in fewer GHG emissions.	• Expected to be mature by decommissioning	• This equipment may be harder to resource.

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5.7 COMPARISON TO BEST-IN-CLASS GLOBAL PROJECTS

In this section, the Project's GHG emissions performance is compared with similar projects in Canada and internationally.

5.7.1 LNG Canada

LNG Canada is a large LNG facility located near Kitimat, BC. This facility underwent a federal environmental assessment and received its certificate in 2015. Construction of the facility is currently underway. Like the Project, LNG Canada must meet the 0.16 t CO_2e/t LNG limit legislated in the GGIRCA. A comparison of LNG Canada with the Project is provided in Table 5.7–1. For details on the Project's GHG emissions, see Section 6.9 or the GHG TDR (Appendix 8A to the Application).

Table 5.7–1 Comparison: The Project to LNG Canada

Category	Project	LNG Canada[A]
Processing size (MTPA)	12	26
Primary energy source	Renewable hydroelectricity via BC Hydro grid connection	Natural gas turbines for main refrigeration compressors
Secondary energy source	Combined cycle natural gas turbines (temporary)	Renewable hydroelectricity via BC Hydro grid connection (auxiliary electricity supply)
Electricity demand from grid (avg)	600 MW for 100% electric power	235 MW for auxiliary power
Construction emissions, including land clearing	Up to 237,134 t CO_2e	255,742 t CO_2e
Thermal oxidizer emissions	118,226 t CO_2e/y	775,636 t CO_2e/y
Annual operations GHG emissions	252,636 t CO_2e/y including tugboats and LNGC marine emissions 1,867,992 t CO_2e/y, including tugboats and LNGC and using power barges	3,957,728 t CO_2e/y, including tugboats but not LNGC marine emissions
Emissions intensity	• 0.018 t CO_2e/t LNG when using BC Hydro power (excludes marine) • 0.153 t CO_2e/t LNG when using power barges (excludes marine) See Section 6.9 for details	0.152 t CO_2e/t LNG (excludes marine)

Table 5.7–1 Comparison: The Project to LNG Canada

Category	Project	LNG Canada[A]
GHG mitigation measures (operation)	Technology: • BC Hydro connection for primary energy source • Waste heat integration • Boil-off gas recovery • Use of dual fuel diesel/LNG tugboats • Welded connection for hydrocarbon piping • Valves with lower steam leak rates • Flaring of natural gas during maintenance, upset, or emergencies Practice: • Fugitive emissions survey • Net-zero plan • Require that LNGCs use boil-off gas while berthed • Measurement of electricity/fuel consumption • Regular maintenance • Optimal sizing	Technology: • BC Hydro power connection for auxiliary energy source • Efficient aero-derivative turbines • Waste heat integration • Boil-off gas recovery • Use of electric tugboats Practice: • Minimize flaring and venting • Preventative maintenance • Fugitive emissions survey • GHG Management Plan
Net-zero commitment in place	Yes, see Section 6.0.	No[B]
NOTES: [A] At full buildout [B] The LNG Canada Application was submitted prior to the publication of the SACC, hence a net-zero plan was not required.		

The key difference between the two projects is that the Project is designed to be fully electrified, whereas LNG Canada is designed to use gas turbines for its highest loads (the compressors) and electricity for its other loads. The Project can achieve a lower emissions intensity than LNG Canada because of the full electrification.

5.7.2 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, each producing 5.2 MTPA 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 LNG project uses natural gas combustion to generate electricity for its operations (Delphi Group 2013).

The Gorgon LNG project uses carbon capture and storage (**CCS**) as a mitigation measure. It was designed to store up to 4 million tonnes of CO_2 per year (Chevron 2022a). Since CCS came online in 2019, Gorgon LNG has stored 7 million tonnes of CO_2, or approximately 2.3 million tonnes CO_2 per year (Chevron 2022b). During the 2021–2022 financial year, Gorgon LNG injected approximately 33% of the CO_2 that was already present in the natural gas brought up for processing. Chevron notes that Gorgon LNG is not meeting its commitments with respect to CCS level of service, and this is resulting in Chevron purchasing and retiring 7.53 million offsets in 2022 (Chevron 2022b). Based on the description of the CCS shortfall in the Chevron (2022b) report, additional shortfalls are expected.

A comparison of Gorgon LNG with the Project is provided in Table 5.7–2. For details on the Project's GHG emissions, see Section 6.9 or the GHG TDR (Appendix 8A to the Application).

Table 5.7–2 Comparison: The Project to Gorgon LNG

Category	Project	Gorgon LNG[A]
Processing size (MTPA)	12	15
Primary energy source	Renewable hydroelectricity via BC Hydro grid connection	Natural gas turbines
Secondary energy source	Combined cycle natural gas turbines (temporary)	Not applicable
Construction emissions, including land clearing	Up to 237,134 t CO_2e	Not available
Thermal oxidizer emissions	118,226 t CO_2e/y	847,700 t CO_2e/y[B]
Annual operations GHG emissions	252,636 t CO_2e/y including tugboats and LNGC marine emissions 1,867,992 t CO_2e/y, including tugboats and LNGC and using power barges	5,372,630 t CO_2e/y, not considering carbon storage or marine emission sources
Emissions intensity	• 0.018 t CO_2e/t LNG when using BC Hydro power (excludes marine) • 0.153 t CO_2e/t LNG when using power barges (excludes marine) See Section 6.9 for details	0.27 t CO_2e/t LNG (excludes marine)

Table 5.7–2 Comparison: The Project to Gorgon LNG

Category	Project	Gorgon LNG[A]
GHG mitigation measures (operation)	Technology: • Renewable hydroelectricity via BC Hydro connection for primary energy source • Combined cycle power barges as temporary energy source • Waste heat integration • Boil-off gas recovery • Use of dual fuel diesel/LNG tugboats • Welded connection for hydrocarbon piping • Valves with lower steam leak rates • Flaring of natural gas during maintenance, upset, or emergencies Practice: • Fugitive emissions survey • Net-zero plan • Require LNGC use boil-off gas while berthed • Measurement of electricity/fuel consumption • Regular maintenance • Optimal sizing	Technology: • Aeroderivative gas turbines • CCS • Waste heat recovery Practice: • Unknown
Net-zero commitment in place	Yes, see Section 6.0.	No

NOTES:
[A] Values are from planning stage and may not reflect current operating conditions (Delphi 2013).
[B] Although not clear in the reference, this value likely does not take carbon capture into account.

Although Gorgon LNG was designed for substantive CO_2 reductions, operational difficulties have prevented it from meeting its commitments.

5.8 PROJECT'S BEST-IN-CLASS EMISSIONS PERFORMANCE

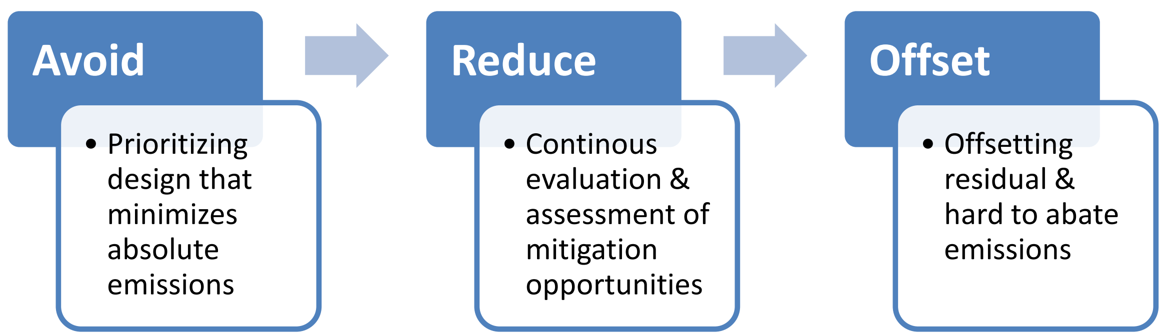
The draft Guidance with respect to demonstrating best-in-class GHG emissions performance was released by ECCC in 2022 (ECCC 2022a). The best-in-class principles are focusing on emission reductions prior to offsetting and continuous improvement of emissions performance over the lifetime of the Project.

The Project's net-zero plan takes an already best-in-class Project and confirms the Proponents commitments to climate change action.

6.0 NET-ZERO PLAN

6.1 NET-ZERO APPROACH TO MITIGATION

The Proponent's net-zero plan is designed based on three principles: (1) prioritize the avoidance of emissions during design and engineering phases, (2) continuous evaluation and assessment of further emission reductions based on changing environment, and (3) offsetting residual emissions aligned with the Project's offset framework.



6.1.1 Avoiding Emissions

The Project is being conceived with a strong commitment to using the best-in-class, feasible, low-emission equipment and processes as previously outlined. The Project is furthermore designed to use electricity for power from day one of operations. By connecting to the BC Hydro electrical grid instead of self-generating electricity, a GHG emission reduction of 98% can be realized from primary energy demand, and a 90% GHG emission reduction from the Project's overall emissions.

6.1.2 Reducing Emissions

The Proponents will continually evaluate and assess new technologies as they become feasible for use at the facility. This commitment will be supported by the establishment of a committee that will perform a net-zero review every five years. This committee will consist of relevant stakeholders and rightsholders, to be finalized at a later date. The committee will provide non-binding, strategic advice and recommendations to the Project on GHG emissions reduction opportunities, potential offsets, and general net-zero strategy.

As described in Section 5.3.2.3 and 6.8.1, the Project has identified future potential GHG mitigation opportunities that, as future cost reductions and advancements begin to create more favourable economic conditions for such a project, including a stable, clear, and consistent climate policy (i.e., Carbon Tax, robust offset credit system, carbon reduction incentive programs), could further mitigate an estimated 75% of the fully-electrified facility's remaining direct, on-shore emissions.

6.1.3 fsetting Emissions

Remaining, hard-to-abate emissions will be offset with a priority for purchases of high-quality, credible carbon credits from within BC. The Project's offset strategy will prioritize Indigenous-led offset projects that result in emissions reductions and removals within BC.

This net-zero plan has been developed to work in parallel and in support of advancing economic reconciliation with Indigenous peoples. Defensible, rigorous, and effective measures to reduce GHG emissions and meet net-zero commitments from the Project are critical for BC to meet targets for greenhouse gas reduction. It is equally important to develop these measures in collaboration with the Nisg̲a'a Nation and to provide meaningful, long-lasting benefits to participating Indigenous nations in a manner that supports their traditional culture, values, and interests.

As a result, the Proponents are committed to utilizing the net-zero plan to explore potential mitigation opportunities such as:

- Purchasing of high-quality carbon offsets from Indigenous communities in-region
- Involving Indigenous communities in the development of nature-based solutions to enhance natural and technological carbon sinks
- Developing training programs for Indigenous peoples to participate in GHG emission monitoring and reporting activities
- Promoting clean energy, energy efficiency and energy self-sufficiency programs in local Indigenous communities
- Enabling local Indigenous communities to prepare for the impacts of a changing climate.

Engagement with the Nisg̲a'a Nation and other participating Indigenous nations is essential to ensuring that the Project continues to positively advance meaningful and real reconciliation within the Province of BC and Canada, including the inclusion of Indigenous knowledge and experience with climate change. The Proponents will ensure an iterative process with interested and affected communities is maintained with regards to the net-zero plan's development and implementation, throughout the life of the Project.

6.2 ALIGNMENT WITH FIRST NATIONS CLIMATE INITIATIVE

The Project is being co-developed with the Nisg̲a'a Nation and Project proponents, Rockies LNG and Western LNG.

The Nisg̲a'a Nation are a founding member of the First Nations Climate Initiative (FNCI). The FNCI is an Indigenous-led policy initiative focused on assisting Canada, BC, Alberta, and Indigenous nations in meeting international, national, provincial and Indigenous nation objectives to address global climate change due to GHG emissions. A major policy initiative of FNCI is the promotion of net-zero LNG, and associated infrastructure, as a transition step to the low carbon economy of the future while supporting "economic self-determination and restoration of traditional territories". It is important to the Nisga'a Nation that this Project work towards net-zero LNG production that is consistent with FNCI objectives through:

- Using renewable hydroelectricity from BC to power the LNG facility
- Using Canadian natural gas with lower life-cycle emissions as the LNG feedstock
- The adherence of upstream natural gas production to strong Canadian upstream GHG and CH_4 emission regulations
- The short shipping distance to Asian markets

The net-zero plan outlined below is designed to align with this initiative and meant to represent the expressed intent and direction of the FNCI.

6.3 ALIGNMENT WITH NET-ZERO POLICY

The Project will be net-zero. A net-zero design utilizing electric-drive compression technology has been, and continues to be, the foundational design principle of the Project. This commitment was established well before the BC government's proposed NZNI policy and was reaffirmed in a letter from the Nisga'a Nation to the provincial government in March of this year (NLG 2023).

The Proponents are fully committed to the development and implementation of a credible plan to pass an emission test to be net-zero by 2030, consistent with proposed policy outlined in the New Energy Action Framework. The foundation of the Project's credible plan is electric drive compression technology and rests on the ability of BC Hydro to deliver sufficient power to the Project's POI. The Project will be ready to accept this power at commissioning – a position we have called 'net-zero ready'.

Being 'net-zero ready' requires working with the BC government and BC Hydro to ensure that BC Hydro is in a position to deliver grid supplied power to the Project POI and to have sufficient power supply available for the Project by the time it is ready to commence operation. Additionally, and to reduce emissions to the required 'net-zero' level, the Proponents are committed to developing a strong GHG management framework and a carbon offset and credit utilization program that prioritizes participating Indigenous nation-led carbon offsets including nature-based solutions, consistent with the finalization of compliance options under the Net-zero New Industry Intentions Paper (NZNIIP).

The Proponents' commitment to be net-zero as detailed above is caveated by the fact that the NZNIIP is still undergoing active consultation with Indigenous rightsholders and stakeholders. As such, detailing commitments or plans specific to the draft NZNIIP would be premature and out-of-step with the principles of meaningful engagement. At the same time, the Proponents reiterate the commitment to be net-zero and to continuing dialogue with the BC government to ensure it can align with the New Energy Action Framework and the final NZNIIP.

BC Hydro and the BC government have made significant progress to accelerate transmission and to advance power supply in the northwest as outlined in SACC Section 6.4. However, in the increasingly unlikely event that BC Hydro is not able, over the next seven years, to build the required transmission to support the Project with power at the time of commissioning, we are committed to working with the BC government, stakeholders, and rightsholders to find viable solutions to address the temporary increase in emissions until such time as BC Hydro has completed the grid interconnection for the Project. This could include exploring a variety of abatement options, including, but not limited to, additional decarbonization commitments, carbon offset adjustments against future potential credit generation, or the potential for phasing of power for commissioning and operations based on a more detailed understanding of transmission and power availability within the system.

If temporary gas turbines are required, the Proponents commit to removing them once the necessary transmission infrastructure is provided by BC Hydro to supply power to the Project.

6.3.1 Scope

Net-zero emissions is defined as the Project's direct emissions (e.g., from facility operation) plus acquired emissions (e.g., electricity use) minus any offset measures and must equal 0 kt CO_2e.

The following scope outline for the net-zero plan is in alignment with existing 2050 (federal) and proposed 2030 net-zero targets (provincial) and is subject to the finalization of future policy details including the NZNIIP:

- In 2030, the direct emissions covered by the Project's net-zero plan include those from venting, flaring, fugitives, industrial processes, and the emissions associated with purchase of electricity from BC Hydro, as identified in the draft NZNIIP.
  - While the Proponents await a commitment from BC Hydro to provide sufficient power and transmission to the facility by 2030, the Proponents will continue to engage with the Climate Action Secretariat, Energy, Mines and Low Carbon Innovation, and other branches of the BC government, to develop and, if necessary, implement a plan to meet net-zero requirements during this temporary, transitionary phase. The Proponents will meet all applicable legal requirements during construction, operation, and decommissioning.
- In 2050, marine emissions have been added to the offset total in alignment with the SACC.
  - In July 2023, the International Marine Organization Member States adopted the 2023 IMO Strategy on Reduction of GHG Emissions from Ships, with enhanced targets to tackle harmful emissions. The revised IMO GHG Strategy, adopted at the Marine Environment Protection Committee (MEPC 80) includes an enhanced common ambition to reach net-zero GHG emissions from international shipping by or around 2050 (IMO 2023). This includes a commitment to ensure an uptake of alternative zero and near-zero GHG fuels by 2030, as well as indicative check-points for international shipping to reach net-zero GHG emissions for 2030 (by at least 20%, striving for 30%) and 2040 (by at least 70%, striving for 80%). As net-zero is being managed by the IMO, it is assumed that marine emissions will decrease over time and the

additional required number of offsets under the SACC net-zero by 2050 requirements will be smaller than identified.

6.4 ELECTRIFICATION

Electrification of the Project is not only a requirement to achieve emission targets and the Project's net-zero commitment, but it is also one of the key features of the Project for its investors and customers. The Proponents anticipate that an interconnection agreement with BC Hydro will be one of the milestones toward reaching an affirmative final investment decision (FID) and commencing construction on the Project.

The Proponents, in addition to developing a credible GHG management and offset strategy to eliminate residual emissions, have also taken significant steps to advance a timely connection to the BC Hydro system including:

- Commencing the request for service and interconnection process with BC Hydro.
- Working with BC Hydro as a Project proponent to accelerate the grid interconnection process, with a focus on the 500 kV line from Glennanan substation (near Fraser Lake, BC) to Skeena substation (near Terrace, BC).
- Working closely with BC Hydro, Nisg̲a'a Nation, the BC government and others to complete studies to support a 287 kV transmission line that will provide upgraded connection from the Skeena substation.
- A 287 kV line will be built, owned and operated by a third party that will connect the Project at the Site to the BC Hydro grid. The 287 kV interconnection segment construction timeline will ensure the Project is ready for renewable, BC Hydro grid power supply in advance of 2030.
- Submitted an expression of interest in the BC Hydro North Coast BC Expression of Interest process.

Based on recent BC Hydro and BC government activities, the Proponents are confident that BC Hydro will be in a position to provide the required transmission infrastructure needed to electrify the Project by 2030. BC Hydro and the Province of BC have also taken numerous steps to facilitate the timely electrification of BC including:

- In December 2022, the Mandate Letter from Premier Eby to Minister of Energy, Mines and Low Carbon Innovation Josie Osborne includes direction to “improve timing and transparency of permitting processes to support sustainable economic development.”
- Initiating the North Coast BC Expression of Interest to assess the need for new transmission infrastructure to bring clean, reliable, low-cost electricity to the North Coast of BC the result of which was 29 submissions across hydrogen, mining, ports, and LNG projects providing diverse and strong demand for the proposed 500 kV transmission line from Prince George to Terrace.
- Under the New Energy Action Framework announced in March 2023, the BC government established a BC Hydro task force to accelerate the electrification of BC’s economy.

- BC Hydro announced its first call for power in 15 years with the objective of procuring 3,000 GWh per year of clean or renewable energy from new generation, with the first in-service dates designed for 2028.

The Proponents are committed to continuing to work with BC Hydro, the Government of British Columbia, the Nisg̱a'a Nation, and other Indigenous nations to facilitate the timely provision of renewable electricity to the Project.

6.5 EMISSION TARGETS

The Project is being designed and constructed based on the best-available-technologies and best-environmental practice as identified in Section 5.6. From the start of operations, the Project will be one of the lowest-emission intensity LNG facility in the world; a best-in-class facility.

The Proponents are committed to continuous improvement such that facility scope 1 and 2 emissions are minimized throughout the life of the Project. This includes the continuous review of potential scope 1 and 2 emissions over the life of the Project as identified mitigation technology and practices become technically and economically feasible, as well as socially acceptable.

In alignment with Section 6.6 below, the Proponents are committed to establishing, reviewing, and monitoring emissions targets in consultation with the BC Climate Action Secretariat, Indigenous nations, and the Ministry of Energy, Mines and Low Carbon Innovation, once the facility has established a normal operations baseline. Any future targets will take into consideration emission reduction targets and schedules as set out in relevant Provincial statues and supporting policies, internal and external analysis of best available technologies, practices and processes that minimize GHG emissions including rationale and explanation as to the technologies and measures implemented and those that are not implemented.

6.6 GOVERNANCE AND REVIEW OF THE NET-ZERO PLAN

The net-zero plan will be reviewed every five years. Progress reports will be provided annually on key metrics of the plan.

The Proponents will establish a committee of relevant stakeholders to perform this five-year review. This committee will consist of relevant stakeholders, finalized at a later date, including the Nisg̱a'a Nation, Western LNG, Rockies LNG, provincial and federal government stakeholders, potentially impacted Indigenous nations, and other relevant identified stakeholders. The committee will provide non-binding, strategic advice, and recommendations to the Project on GHG emissions reduction opportunities, off-setting strategy and general net-zero strategy.

As part of the five-year review process, the Proponents will undertake a fulsome technological and process review on emission reduction costs and opportunities under the current and expected regulatory and policy framework to ensure that the facility is aligned with its goals and objectives as well as the net-zero ambitions of British Columbia and Canada.

Reviews will include adjustments to scenarios to account for new information and new mitigation strategies that may be identified because of new technology or practices that have become more economically feasible. Review methodology and outcomes will be conducted in concert with the Review Committee, but may include:

- A thorough review of the GHG emissions inventory, identifying any new emissions sources and changes to the inventory boundaries
- Update and adjust the GHG emissions baseline, if there have been significant changes to their GHG emissions inventory.
- Review the net-zero pathway assumptions and update scenarios to reflect new knowledge and developments.
- Update mitigation strategies based on new knowledge.
- Review of the Project's offset strategy and performance.

6.7 SCHEDULE FOR IMPLEMENTATION

The Project is being designed and constructed based on the best available technology and best environmental practice identified in Section 5.0, resulting in the lowest emission intensity LNG facility globally.

The Proponents are committed to the continuous evaluation and assessment of emission reductions throughout the life of the Project. As part of the regular review of the net-zero plan (outlined in Section 6.6 above) and as best-practices continue to be refined on mitigation measures and opportunities, the Proponents are committed to continually update its BAT/BEP assessment and implement emission reduction opportunities as they become feasible over time.

Proponents will use these regular reviews and the monitoring of mitigation opportunities to make future decisions and investments aligned with the net-zero plan. Proponent decision-making will be based on numerous factors including associated costs, technical challenges, risks, infrastructure requirements, global competitiveness, government policies and stakeholder and rights holder considerations.

6.8 ADDITIONAL MITIGATION

As outlined in the Government of Canada's *Technical Guide Related to the Strategic Assessment of Climate Change* (ECCC 2021), the plan must also include proposed emission reductions at specified intervals up to 2050 and must be aligned with the schedule of the mitigation measures that will be implemented (aligned with BAT/BEP). The following section outlines a number of additional mitigation measures that align with the BAT/BEP performed for the Project and which will or have the potential to result in positive impact on future scope 1 and 2 emissions and the Project's overall net-zero plan.

6.8.1 Implementation of CCUS Technologies

CO_2 capture, transport, and possible utilization or storage at the Project was determined to not be feasible due to technical and economic feasibility (see Section 5.3.2.3).

However, there remains potential for a separate project, in the future, to accomplish the removal of carbon contained in the Project's inlet natural gas supply. Such a project could be considered upstream of the Project, closer to geology and infrastructure appropriate for storage and transportation, such as near the natural gas transmission pipeline in northeastern BC, which has depleted gas pools and deep saline formations suitable for CO_2 storage.

The facility's acid gas removal units are needed to meet specifications for liquefaction of the natural gas and prevent damage to liquefaction equipment. The acid gas removal units will produce an acid gas stream mainly composed of CO_2, with potentially small amounts of hydrogen sulfide and hydrocarbons, which will be incinerated using a thermal oxidizer to allow for complete destruction of any hydrocarbons and sulfur compounds. The CO_2 present in the acid gas is not destroyed and is released to the atmosphere.

If the CO_2 was captured and sequestered from the feed natural gas upstream of the Project, there would be minimal emissions from the facility's acid gas removal units and thermal oxidizer resulting in significantly (~47%) lower direct emissions from the Project.

The low CO_2 content of the feed natural gas challenges the economic feasibility of CCUS facilities upstream of the Project. Further, there is currently a lack of well-established CO_2 sequestration infrastructure in northeastern BC. The expected operating cost savings from sequestering the small amount of CO_2 entrained in the natural gas would be insufficient to economically justify the capital cost of CCUS facilities upstream of the facility, even when including current incentives in place.

A substantial amount of work and investment is being made into Carbon Capture Utilization and Storage (**CCUS**) technology and infrastructure. It is reasonable to project future cost reductions and advancements that begin to create more favourable economic conditions for such a project. This, in addition to continued, stable and consistent climate policy (i.e., Carbon Tax, robust offset credit system, carbon reduction incentive programs) create the future potential of upstream CCUS being deployed and reducing emission at downstream sources for which CCUS is not expected to achieve economic or technical feasibility.

Based on the current feed natural gas volume and composition and the estimated removal efficiency of the CCS technology, approximately 100,000 tonnes/year of CO_2 could be captured and sequestered upstream of the LNG facility. Should this CO_2 be removed upstream of the facility, additional reductions (approximately 50,000 tonnes/year) in CO_2 emissions could potentially be eliminated by reducing the need for process heat at the FLNGs that is normally used in the acid gas removal process. Therefore, a total of 150,000 t CO_2e/year could be reduced if CCS is employed upstream of the Project. This future mitigation option has the potential to further mitigate an estimated 75% of the fully electrified Project's direct, terrestrial emissions.

6.8.2 Leak Detection and Repair Program

The Proponent will implement a leak detection and repair program to reduce fugitive GHG emissions during operations. This program will take into consideration provincial and federal regulatory requirements and practices as well as the best available technology including assessing drone, satellite and continuous monitoring options and best available practices identified in Section 5.6.3 of the BAT/BEP.

6.8.3 Heat Recovery

The heaters which will warm the heating medium will be forced draft heaters with ultra low-NOx burners. They convey heat to a synthetic heating medium that is circulated in a closed loop system to provide process heat to several exchangers in the feed gas treating unit. Some of this heat is later recovered by crossing the heated gas streams with, for example, the incoming feed gas. The heater manufacturer will be required to meet the emissions requirements of the national *Multi-Sector Air Pollutants Regulation*s.

The heating medium heaters are designed to heat a synthetic heating medium that is circulated throughout the feed gas treatment unit to provide heat for the acid gas removal unit and other pieces of equipment. Stack gas heat recovery does not apply to this type of a heater because the heater is already designed to efficiently transfer heat to the circulating medium. However, the concept of process waste heat recovery has been incorporated into the design via the use of two other exchangers:

- Feed gas heater – waste heat in the gas stream treated in the amine absorber is used in a cross exchanger with the incoming feed gas to the absorber to heat the latter to a temperature suitable for treatment. This exchanger recovers approximately 10.2MW of heat (per FLNG) from the gas stream during normal operation.
- Rich/lean amine cross exchanger – waste heat from the lean amine stream exiting the amine regenerator is used to heat the rich amine stream before it enters the regenerator, recovering approximately 11.8 MW (per FLNG) of heat.

The use of these two exchangers will recover approximately 22 MW per FLNG of heat, which would have to otherwise be provided by additional fired heater load or electrical heat exchangers.

With regard to the thermal oxidizer, due to space constraints on the FLNG, a conventional thermal oxidizer without heat recovery has been included in the design. Stack gas heat recovery for this service would be complex, as lowering the flue gas temperature could have environmental consequences (due to impacts on dispersion) and technical (metallurgical) challenges.

6.8.4 Offset Credits

The Proponents intend to purchase offset credits consistent with the net emissions tables in Section 6.9.1. The Proponents will prioritize the use of offset credits from participating Indigenous nations. Offset credits will align with the appropriate requirements under BC's proposed NZNIIP and BC Offset Protocols. Doing so confirms that the offset credits meet all of the general principles this framework intends to achieve, such as being of high quality, and reflecting additional, quantified, verified, unique, permanent, and real emissions reductions.

The Proponents will closely align the offset strategy with recognized best-practices for net-zero aligned carbon offsetting to ensure credibility and flexibility of the plan as policy and practices evolve. The Proponents intend to use a variety of high-quality, verifiable offsets aligned with the provincial ambitions of a net-zero economy including avoided or emission reductions and negative emission offsets both nature-based and technological in nature. Over time, the Proponents will focus offsetting activities on carbon removal activities with long-lived storage potential. The timing of offset purchases will require dialogue with government, Indigenous nations, and other stakeholders.

The Proponents will prioritize the use of offset credits from participating Indigenous nations. The Proponents are currently exploring other credit development opportunities and remain committed to working with Indigenous nations and interested parties that may have desired offset projects under consideration. The broader Project region has significant offset opportunities and as such, the Proponents intend to explore such options and conduct similar investigatory studies with other participating Indigenous nations that are impacted by the Project. This commitment will be made through direct conversations with interested Indigenous nations and informed by the work of the FNCI around nature-based solutions.

The Proponents have undertaken a preliminary investigation of potential nature-based solutions offsets with the Nisga'a Nation. The Proponents and the Nisga'a Nation have engaged with a third-party to conduct a feasibility study of forestry offset potential among the Nation's over 200,000 ha of Treaty Land. The forest contains many of the elements that would be considered suitable to a forest carbon offset project, and thus presents an opportunity to create a significant amount of carbon offsets.

This preliminary work has identified numerous potential carbon credit generation opportunities including forest restoration and rehabilitation, implementing ecosystem-based management and deferred harvest. Carbon offsets generated from a Nisga'a Nation carbon project could be used to offset some or all the emissions from the Project. The project would have other benefits to Nisga'a Lands, including increased forest growth, ecological and bio-diversity benefits, and restoration of a portion of the degraded Nass Bottomlands. The Nisga'a Nation and the Proponents continue to advance this work.

6.8.4.1 Offset Credits Under Alternative Case

In March 2023, the BC government introduced the New Energy Action Framework (NEAF). The NEAF proposed legislation requires all prospective LNG facilities in or entering the environment assessment (**EA**) process to pass an emission test with a credible plan to be net-zero by 2030. In July, a draft NZNIIP was released, kicking-off a period of rightsholder and stakeholder engagement on the specific requirements of the proposed Net-Zero for New Industry Policy. The Project continues to engage with the Climate Action Secretariat and other branches of the BC government in the development of the draft policy, including the offsetting requirements for new facilities to meet net-zero.

The Proponents will meet all applicable legal offset requirements during construction, operation, and decommissioning. As the NZNIIP is currently undergoing stakeholder and rightsholder engagement and is in draft form, it is premature to address its implications on the Project's net-zero plan, specifically the offset strategy. The government has yet to finalize critical details including compliance options and offset eligibility.

The Proponents remain committed to working with the BC government and BC Hydro to achieve a fully-electrified, net-zero facility starting at commissioning. In the event BC Hydro is not able to supply the Project with power at this time, the Proponents are committed to working with the BC government, stakeholders, and rightsholders to find viable solutions to address the temporary increase in emissions in the presented alternative case, until such time as BC Hydro has completed the grid interconnection to the Project's POI.

The Proponents are committed to ensuring that the Project's net-zero plan is credible and consistent with the intent of the New Energy Action Framework.

6.8.5 Potential New Federal and Provincial Policy

A number of projected policies currently under development would have a significant impact on the net emissions over the life of the Project. These additional measures are outside the Proponent's control and yet could result in direct emission reductions. They would have an important impact on the Project's net-zero plan, climate objectives, and ultimately the number of direct offsets required.

- Electricity:
  - British Columbia 100% Clean Electricity Delivery Standard
    - CleanBC 2030 commits BC Hydro to the provision of 100% renewable, clean electricity by 2030.

When enacted, this would have two impacts on the Project:

- A potential reduction of acquired emissions
- A potential reduction in required offsets to be purchased by the Project to achieve net-zero.

6.9 NET EMISSIONS

In this section, net emissions for the Project are provided in both the Base Case, Alternative Case, and the Base Case plus additional mitigation and future policies. Each scenario reflects combination 1 from the BAT/BEP summary in Section 5.6.3. Emissions are provided on an annual basis. As outlined in Section 6.8.3, the Project intends to purchase GHG emissions offsets to mitigate hard to abate emissions. The quantity of carbon offsets to be purchased is intended to be matched to the amount of GHG emissions associated with acquired energy (i.e., imported power from the BC Hydro grid) and other direct GHG emissions not associated with self-generated power, for both the operations Base and Alternative Cases. Two net emissions columns have been included under the net-zero plan to accommodate the different requirements in BCs proposed NZNIIP and the SACC. For the period of 2028–2050, the net emissions under the NZNIIP do not include those attributed to marine emissions (Net GHG Emissions – BC). For the period of 2050–2057, marine emissions are included in “Net GHG Emissions – BC” column. The “Net GHG Emissions – SACC” column includes marine emissions. See section 6.3.1 for scope discussion.

6.9.1 Net Emissions – Base Case

The emissions profile for this Project, reflecting emission reduction combination 1 (see Section 5.6.3), is provided on an annual basis in Table 6.9–1. It is assumed that sufficient power is available at start-up and the Proponents will purchase offset credits as per the net-zero plan in Section 6.3 to achieve net-zero. Net emissions until 2050 are consistent with the draft scope of emissions required under the BC NZNIIP. Marine emissions are included in the net-zero net GHG emissions calculation post 2050. Direct emissions during construction include those from land-use change.

Table 6.9–1 Net Emissions – Base Case

Year	Direct GHG[a] Emissions – SACC (t CO_2e/y)	Direct GHG[a] Emissions – BC (t CO_2e/y)	Acquired Energy GHG Emissions (t CO_2e/y)	CO_2 Captured and Stored (t CO_2e/y)	Avoided Domestic Emissions (t CO_2e/y)	Offset Credits (t CO_2e/y)	Net GHG Emissions – SACC (t CO_2e/y)	Net GHG Emissions – BC (t CO_2e/y)	Emissions Intensity (Before Offsets – BC) (t CO_2e/t LNG)	Emissions Intensity (Before Offsets – SACC) (t CO_2e/t LNG)
Construction										
2024	20,133	20,133	-	-	-	-	20,133	20,133	-	-
2025	20,133	20,133	-	-	-	-	20,133	20,133	-	-
2026	20,133	20,133	-	-	-	-	20,133	20,133	-	-
2027	20,133	20,133	3,370	-	-	-	23,503	23,503	-	-
Operations										
2028	223,990	187,575	41,400	-	-	228,975	36,416	0	0.019	0.022
2029	223,990	187,575	61,257	-	-	248,831	36,416	0	0.021	0.024
2030	223,990	187,575	36,033	-	-	223,608	36,416	0	0.019	0.022
2031	223,990	187,575	32,430	-	-	220,005	36,416	0	0.018	0.021
2032	223,990	187,575	32,430	-	-	220,005	36,416	0	0.018	0.021
2033	223,990	187,575	32,430	-	-	220,005	36,416	0	0.018	0.021
2034	223,990	187,575	28,827	-	-	216,401	36,416	0	0.018	0.021
2035	223,990	187,575	28,827	-	-	216,401	36,416	0	0.018	0.021
2036	223,990	187,575	28,827	-	-	216,401	36,416	0	0.018	0.021
2037	223,990	187,575	28,827	-	-	216,401	36,416	0	0.018	0.021
2038	223,990	187,575	28,827	-	-	216,401	36,416	0	0.018	0.021
2039	223,990	187,575	25,223	-	-	212,798	36,416	0	0.018	0.021

Table 6.9–1 Net Emissions – Base Case

Year	Direct GHG[a] Emissions – SACC	Direct GHG[a] Emissions – BC	Acquired Energy GHG Emissions	CO_2 Captured and Stored	Avoided Domestic Emissions	Offset Credits	Net GHG Emissions – SACC	Net GHG Emissions – BC	Emissions Intensity (Before Offsets – BC)	Emissions Intensity (Before Offsets – SACC)
	(t CO_2e/y)	(t CO_2e/y)	(t CO_2e/y)	(t CO_2e/y)	(t CO_2e/y)	(t CO_2e/y)	(t CO_2e/y)	(t CO_2e/y)	(t CO_2e/t LNG)	(t CO_2e/t LNG)
2040	223,990	187,575	25,223	-	-	212,798	36,416	0	0.018	0.021
2041	223,990	187,575	25,223	-	-	212,798	36,416	0	0.018	0.021
2042	223,990	187,575	25,223	-	-	212,798	36,416	0	0.018	0.021
2043	223,990	187,575	25,223	-	-	212,798	36,416	0	0.018	0.021
2044	223,990	187,575	25,223	-	-	212,798	36,416	0	0.018	0.021
2045	223,990	187,575	25,223	-	-	212,798	36,416	0	0.018	0.021
2046	223,990	187,575	25,223	-	-	212,798	36,416	0	0.018	0.021
2047	223,990	187,575	25,223	-	-	212,798	36,416	0	0.018	0.021
2048	223,990	187,575	25,223	-	-	212,798	36,416	0	0.018	0.021
2049	223,990	187,575	25,223	-	-	212,798	36,416	0	0.018	0.021
2050	223,990	187,575	25,223	-	-	249,213	0	0	0.018	0.021
2051–2057 (each year)	223,990	187,575	25,223	-	-	249,213	0	0	0.018	0.021

NOTES:

[a] The direct emissions covered by the Project's net-zero plan include those from venting, flaring, fugitives, and industrial processes. In 2050, marine emissions will be offset in alignment with the SACC.

For the period of 2028–2050, the net emissions under the NZNIIP do not include those attributed to marine emissions (Net GHG Emissions – BC). For the period of 2050–2057, marine emissions are included in "Net GHG Emissions – BC" column. The "Net GHG Emissions – SACC" column includes marine emissions. See Section 6.3.1 for scope discussion.

6.9.2 Net Emissions – Alternative Case

The emissions profile for this Project, reflecting emission reduction with combination 1, is provided on an annual basis in Table 6.9–2. For this initial net-zero plan, it is assumed that sufficient power is unavailable at start-up, which would require the Project to deploy temporary power-barges. For illustrative purposes, the Project has chosen 2032 based on an estimate in-service date by BC Hydro (BC Hydro 2023) as the year that the interconnection is completed (i.e., the facility uses grid electricity starting in 2033). Offset credits will be purchased at a volume consistent with the Base Case commitment. Direct emissions during construction include those from land-use change.

Table 6.9–2 Net Emissions – Alternative Case

Year	Direct GHG[a] Emissions – SACC (t CO_2e/y)	Direct GHG[a] Emissions – BC (t CO_2e/y)	Acquired Energy GHG Emissions (t CO_2e/y)	CO_2 Captured and Stored (t CO_2e/y)	Avoided Domestic Emissions (t CO_2e/y)	Offset Credits (t CO_2e/y)	Net GHG Emissions – SACC (t CO_2e/y)	Net GHG Emissions – BC (t CO_2e/y)	Emissions Intensity (Before Offsets – BC) (t CO_2e/t LNG)	Emissions Intensity (Before Offsets – SACC) (t CO_2e/t LNG)
Construction										
2024	20,133	20,133	-	-	-	-	20,133	20,133	-	-
2025	20,133	20,133	-	-	-	-	20,133	20,133	-	-
2026	20,133	20,133	-	-	-	-	20,133	20,133	-	-
2027	176,735	176,735	-	-	-	-	176,735	176,735	-	-
Operations										
2028	1,867,992	1,831,576	-	-	-	228,975	1,639,018	1,602,602	0.153	0.156
2029	1,867,992	1,833,447	-	-	-	248,831	1,619,161	1,584,616	0.153	0.156
2030	1,867,992	1,833,447	-	-	-	223,608	1,644,384	*	0.018–0.153	0.156
2031	1,867,992	1,833,447	-	-	-	220,005	1,647,988	*	0.018–0.153	0.156
2032	1,867,992	1,833,447	-	-	-	220,005	1,647,988	*	0.018–0.153	0.156
2033	223,990	187,575	32,430	-	-	220,005	36,416	0	0.018	0.021
2034	223,990	187,575	28,827	-	-	216,401	36,416	0	0.018	0.021
2035	223,990	187,575	28,827	-	-	216,401	36,416	0	0.018	0.021
2036	223,990	187,575	28,827	-	-	216,401	36,416	0	0.018	0.021
2037	223,990	187,575	28,827	-	-	216,401	36,416	0	0.018	0.021
2038	223,990	187,575	28,827	-	-	216,401	36,416	0	0.018	0.021
2039	223,990	187,575	25,223	-	-	212,798	36,416	0	0.018	0.021
2040	223,990	187,575	25,223	-	-	212,798	36,416	0	0.018	0.021

Table 6.9–2 Net Emissions – Alternative Case

Year	Direct GHG[a] Emissions – SACC (t CO_2e/y)	Direct GHG[a] Emissions – BC (t CO_2e/y)	Acquired Energy GHG Emissions (t CO_2e/y)	CO_2 Captured and Stored (t CO_2e/y)	Avoided Domestic Emissions (t CO_2e/y)	Offset Credits (t CO_2e/y)	Net GHG Emissions – SACC (t CO_2e/y)	Net GHG Emissions – BC (t CO_2e/y)	Emissions Intensity (Before Offsets – BC) (t CO_2e/t LNG)	Emissions Intensity (Before Offsets – SACC) (t CO_2e/t LNG)
2041	223,990	187,575	25,223	-	-	212,798	36,416	0	0.018	0.021
2042	223,990	187,575	25,223	-	-	212,798	36,416	0	0.018	0.021
2043	223,990	187,575	25,223	-	-	212,798	36,416	0	0.018	0.021
2044	223,990	187,575	25,223	-	-	212,798	36,416	0	0.018	0.021
2045	223,990	187,575	25,223	-	-	212,798	36,416	0	0.018	0.021
2046	223,990	187,575	25,223	-	-	212,798	36,416	0	0.018	0.021
2047	223,990	187,575	25,223	-	-	212,798	36,416	0	0.018	0.021
2048	223,990	187,575	25,223	-	-	212,798	36,416	0	0.018	0.021
2049	223,990	187,575	25,223	-	-	212,798	36,416	0	0.018	0.021
2050	223,990	187,575	25,223	-	-	249,213	0	0	0.018	0.021
2050–2057 (each year)	223,990	187,575	25,223	-	-	249,213	0	0	0.018	0.021

Table 6.9–2 Net Emissions – Alternative Case

Year	Direct GHG[a] Emissions – SACC	Direct GHG[a] Emissions – BC	Acquired Energy GHG Emissions	CO_2 Captured and Stored	Avoided Domestic Emissions	Offset Credits	Net GHG Emissions – SACC	Net GHG Emissions – BC	Emissions Intensity (Before Offsets – BC)	Emissions Intensity (Before Offsets – SACC)
	(t CO_2e/y)	(t CO_2e/y)	(t CO_2e/y)	(t CO_2e/y)	(t CO_2e/y)	(t CO_2e/y)	(t CO_2e/y)	(t CO_2e/y)	(t CO_2e/t LNG)	(t CO_2e/t LNG)

NOTES:

[a] The direct emissions covered by the Project's net-zero plan include those from venting, flaring, fugitives, and industrial processes.

For the period of 2028–2050, the net emissions under the NZNIIP do not include those attributed to marine emissions (Net GHG Emissions – BC). For the period of 2050–2057, marine emissions are included in "Net GHG Emissions – BC" column. The "Net GHG Emissions – SACC" column includes marine emissions. See Section 6.3.1 for scope discussion.

* The Proponents will meet all applicable legal requirements during construction, operation, and decommissioning. The Proponents are committed to ensuring that the Project's net-zero plan is credible and consistent with the intent of the New Energy Action Framework. As the NZNIIP is currently undergoing stakeholder and rightsholder engagement and is in draft form, it is premature to address the impacts on the Project's net-zero plan, specifically the offset strategy. See Section 6.3 and 6.8.3.1 for more information.

6.9.3 Net Emissions – Base Case under Additional Considerations and Future Policy

For this scenario, the Base Case is considered with the assumption that the government achieves its intended policy of a 100% renewable electricity system by 2030 (see Section 6.8.4). In addition, this scenario assumes that sufficient advancements in technology, policies, and economics allow for upstream CCUS being deployed and reducing emission at downstream sources stating in 2040 (see Section 6.8.1).

This scenario is meant to be illustrative of one of many potential future net emissions scenarios under various assumptions that forecast potential changes in technology, economics, and policy. Parts of the case have been currently assessed as not technically feasible at this time (i.e., CCUS).

Direct emissions during construction include those from land-use change. Table 6.9–3 provides emission for this scenario on an annual basis.

Table 6.9–3 Net Emissions – Base Case under Additional Considerations and Future Policy Base Case

Year	Direct GHG[a] Emissions – SACC (t CO_2e/y)	Direct GHG[a] Emissions – BC (t CO_2e/y)	Acquired Energy GHG Emissions (t CO_2e/y)	CO_2 Captured and Stored (t CO_2e/y)	Avoided Domestic Emissions (t CO_2e/y)	Offset Credits (t CO_2e/y)	Net GHG Emissions – SACC (t CO_2e/y)	Net GHG Emissions – BC (t CO_2e/y)	Emissions Intensity (Before Offsets – BC) (t CO_2e/t LNG)	Emissions Intensity (Before Offsets – SACC) (t CO_2e/t LNG)
Construction										
2024	20,133	20,133	-	-	-	-	20,133	20,133	-	-
2025	20,133	20,133	-	-	-	-	20,133	20,133	-	-
2026	20,133	20,133	-	-	-	-	20,133	20,133	-	-
2027	20,133	20,133	3,370	-	-	-	23,503	23,503	-	-
Operations										
2028	223,990	187,575	41,400	-	-	228,975	36,416	0	0.019	0.022
2029	223,990	187,575	61,257	-	-	248,831	36,416	0	0.021	0.024
2030	223,990	187,575	-	-	-	187,575	36,416	0	0.016	0.019
2031	223,990	187,575	-	-	-	187,575	36,416	0	0.016	0.019
2032	223,990	187,575	-	-	-	187,575	36,416	0	0.016	0.019
2033	223,990	187,575	-	-	-	187,575	36,416	0	0.016	0.019
2034	223,990	187,575	-	-	-	187,575	36,416	0	0.016	0.019
2035	223,990	187,575	-	-	-	187,575	36,416	0	0.016	0.019
2036	223,990	187,575	-	-	-	187,575	36,416	0	0.016	0.019
2037	223,990	187,575	-	-	-	187,575	36,416	0	0.016	0.019
2038	223,990	187,575	-	-	-	187,575	36,416	0	0.016	0.019
2039	223,990	187,575	-	-	-	187,575	36,416	0	0.016	0.019
2040	73,990	37,575	-	-	-	37,575	36,416	0	0.003	0.006

Table 6.9–3 Net Emissions – Base Case under Additional Considerations and Future Policy Base Case

Year	Direct GHG[a] Emissions – SACC (t CO_2e/y)	Direct GHG[a] Emissions – BC (t CO_2e/y)	Acquired Energy GHG Emissions (t CO_2e/y)	CO_2 Captured and Stored (t CO_2e/y)	Avoided Domestic Emissions (t CO_2e/y)	Offset Credits (t CO_2e/y)	Net GHG Emissions – SACC (t CO_2e/y)	Net GHG Emissions – BC (t CO_2e/y)	Emissions Intensity (Before Offsets – BC) (t CO_2e/t LNG)	Emissions Intensity (Before Offsets – SACC) (t CO_2e/t LNG)
2041	73,990	37,575	-	-	-	37,575	36,416	0	0.003	0.006
2042	73,990	37,575	-	-	-	37,575	36,416	0	0.003	0.006
2043	73,990	37,575	-	-	-	37,575	36,416	0	0.003	0.006
2044	73,990	37,575	-	-	-	37,575	36,416	0	0.003	0.006
2045	73,990	37,575	-	-	-	37,575	36,416	0	0.003	0.006
2046	73,990	37,575	-	-	-	37,575	36,416	0	0.003	0.006
2047	73,990	37,575	-	-	-	37,575	36,416	0	0.003	0.006
2048	73,990	37,575	-	-	-	37,575	36,416	0	0.003	0.006
2049	73,990	37,575	-	-	-	37,575	36,416	0	0.003	0.006
2050	73,990	37,575	-	-	-	73,990	0	0	0.003	0.006
2050–2057 (each year)	73,990	37,575	-	-	-	73,990	0	0	0.003	0.006

NOTES:
[a] The direct emissions covered by the Project's net-zero plan include those from venting, flaring, fugitives, and industrial processes.
For the period of 2028–2050, the net emissions under the NZNIIP do not include those attributed to marine emissions (Net GHG Emissions – BC). For the period of 2050–2057, marine emissions are included in "Net GHG Emissions – BC" column. The "Net GHG Emissions – SACC" column includes marine emissions. See Section 6.3.1 for scope discussion.

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6.10 GHG LEGISLATION AND POLICIES

The management of GHG emissions is subject to several statutes, policies, and frameworks. These are identified in the Application Information Requirements and Table 6.10–1 provides a description of the key legislation, policy, and regulatory guidance documents applicable to the assessment of climate change.

Table 6.10–1 Summary of Key Legislation, Policy, and Regulatory Guidance Documents for Climate Change

Regulation or Policy	Description
Federal	
Pan Canadian Framework on Clean Growth and Climate Change (ECCC 2016)	Reduce GHG emissions 30% below 2005 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.
Strategic Assessment of Climate Change (ECCC 2020)	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 GHG 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% to 38% of 2007 levels by 2030.
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.

Table 6.10–1 Summary of Key Legislation, Policy, and Regulatory Guidance Documents for Climate Change

Regulation or Policy	Description
Carbon Tax Act	British Columbia established a price on GHGs beginning at $10/tonne in 2008. On April 1, 2022, the carbon tax rose from $45 to $50/tonne in 2022 (Government of British Columbia nd).
The CleanBC Roadmap to 2030	Reduce GHG emissions 40% below 2007 levels by 2030 and reaching net-zero by 2050.
New Energy Action Framework	Under the new framework, the Province will: • Require all proposed LNG facilities in or entering the environmental assessment (EA) process to pass an emissions test with a credible plan to be net-zero by 2030 • Put in place a regulatory emissions cap for the oil and gas industry to ensure BC meets its 2030 emissions-reduction target for the sector • Establish a clean-energy and major projects office to fast-track investment in clean energy and technology and create good, sustainable jobs in the transition to a cleaner economy • Create a BC Hydro task force to accelerate the electrification of BC's economy by powering more homes, businesses, and industries with renewable electricity.
Net-Zero New Industry Intentions Paper	The Net-Zero New Industry Intentions Paper sets out the Province's proposed approach to delivering the: • CleanBC Roadmap to 2030 commitment to ensure that all new, large, industrial facilities plan to achieve net-zero emissions by 2050 • New Energy Action Framework commitment that all new, large, liquified natural gas (LNG) facilities achieve net-zero by 2030.
Nisg̱a'a Lisims Government	
None applicable	

6.11 ADDITIONAL INFORMATION

6.11.1 Government Assistance

A number of federal and provincial government actions and policies have the potential to affect the Project's net-zero plan including, but not limited to:

- Clarity around and development of a robust offset credit system
- Clarity around new LNG facilities passing an emissions test with a credible plan to be net-zero by 2030 in British Columbia
- Clear, consistent, and stable legislation regarding carbon tax and associated programs
- Continued support for de-carbonization in the energy sector through programs under CleanBC
- Updated Forest Carbon Offset Protocol in British Columbia
- Continued support and acceleration of the electrification of BC's economy through the BC Hydro task force

7.0 CLIMATE CHANGE RESILIENCE ASSESSMENT

A Climate Change Resilience Assessment (**CCRA**) has been conducted to assess risks to the Project due to climate change and to identify adaptation options to 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.

7.1 METHODOLOGY

7.1.1 Overview of Climate Change Resilience Assessment Process

This climate change resilience study assesses the potential 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 area. Extreme weather and climate events may include, but are not limited to: extreme temperatures, freeze-thaw cycles, short duration high intensity rainfall, long duration rainfall, heavy snowfall events, high wind events, occurrences of wildfire, and relative mean sea level rise.

The climate change resilience assessment identifies infrastructure components and their response to selected climate hazards, 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 7.1–1. This CCRA is aligned with the Climate Lens General Guidance v1.2 of Infrastructure Canada which recognizes the ISO 31000:2018 Standard Risk Management—Principles and Guidelines as a suitable methodology for CCRAs.

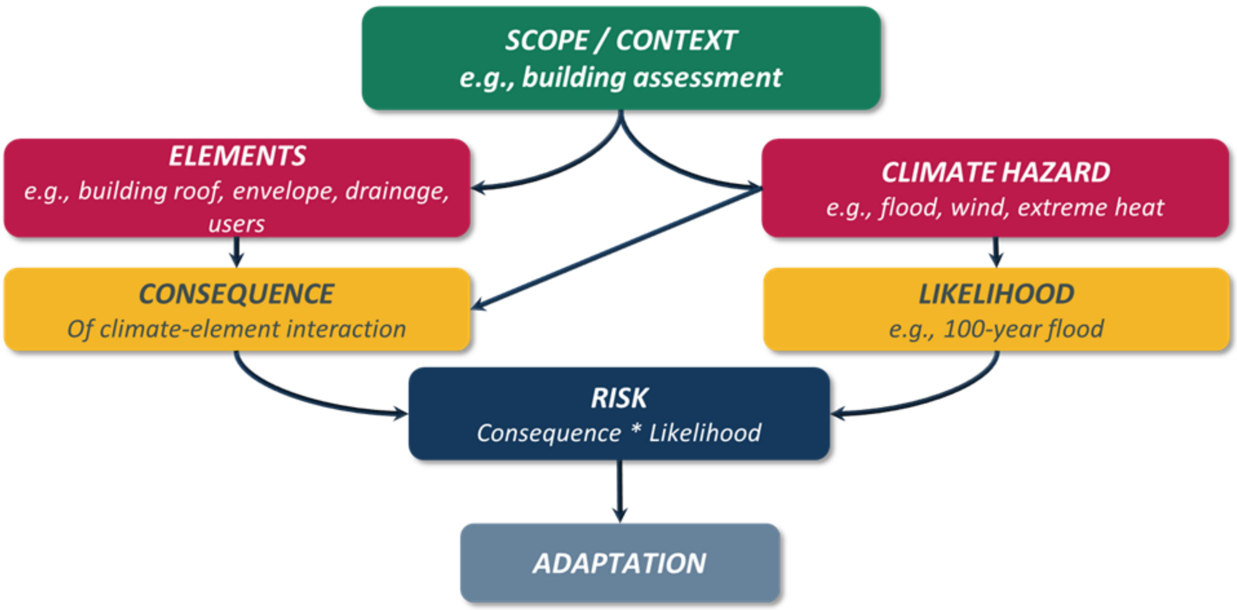


Figure 7.1–1 Illustration of the Risk Assessment Process

7.1.2 Timescale of Assessment

As the Project is expected to be in service until at least 2050, climate change risk assessment is aligned with the Project's operational lifespan or the period 2041 to 2070 (2050s). Current climate is based on weather station data for the periods 1981–2010 to establish the climate baseline.

Climate projections are also presented for the 2080s in Section 7.1.9 for additional information. Short-term (up to 2020s) and longer-term (up to 2080s) climate change implications tend to follow the same trend as the climate parameters for the 2050s, so were not discussed separately.

7.1.3 Plausible Climate Scenarios

Climate modeling associated with the Fifth Coupled Model Intercomparison Project (**CMIP5**) (Taylor et al. 2011) 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 into 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 were 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 (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 2014).

The IPCC established four RCP emissions scenarios – RCP 2.6, RCP 4.5, RCP 6.0, and RCP 8.5. 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 7.1–2). For example, the RCP 2.6 emissions scenario may be achievable with extensive adoption of biofuels/renewable energy and large-scale changes in global consumption habits, along with carbon capture and storage. RCP2.6 is representative of a scenario that aims to keep global warming likely below 2°C above pre-industrial temperatures. RCP 4.5 and RCP 6.0 are considered the ‘medium stabilization’ scenarios where global mitigation efforts result in intermediate levels of GHG emissions (IPCC 2014).

Although some progress has been made, current estimates of GHG emissions are still close to following the RCP 8.5 path (Figure 7.1–2). This assessment is, therefore, based on climate conditions estimated under the RCP 8.5 scenario.

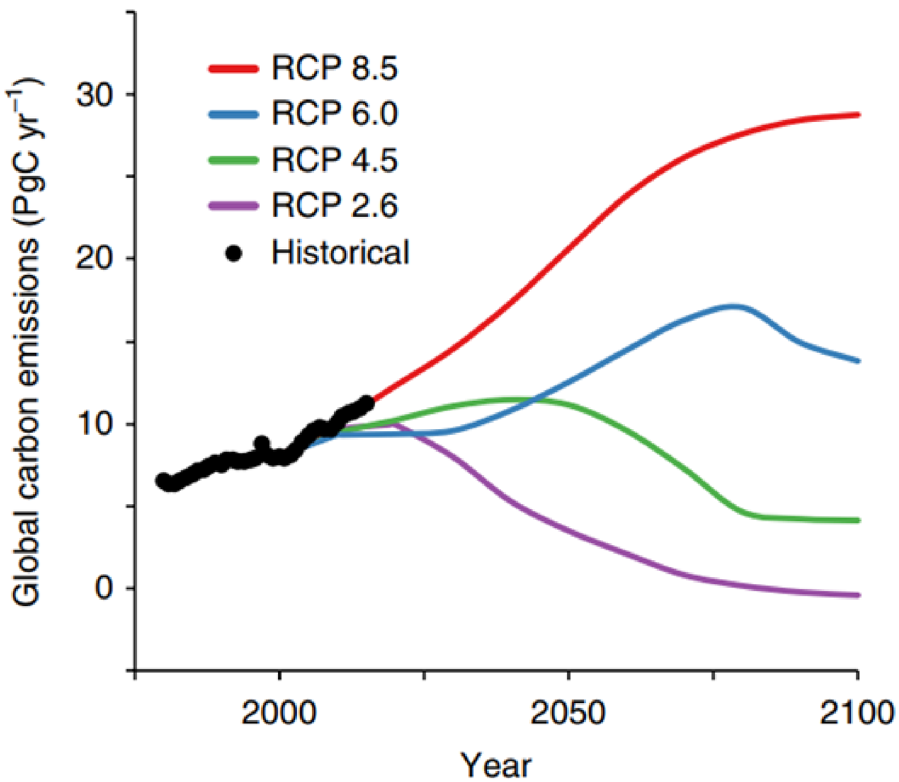


Figure 7.1–2 Historical CO_2 Emissions for 1980-2017 and Projected Emissions Trajectories to 2100 for the Four Representative Concentration Pathway (RCP) Scenarios (Figure source: Smith and Myers 2018)

7.1.4 Climate Profile for the Project Area

7.1.4.1 General Climate Profile

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. A climate profile contains a description of current and future climate based on historical climate records and on climate projections that attempt to predict future climate (developed by global climate models or **GCMs**).

When developing a profile of the historical climate of an area, the most valuable data are typically temperature, precipitation, and wind. Due to year-to-year variability, climate data are typically averaged over a 30-year period. In the development of climate profile for the Project area, the time horizons of 1981–2010 were selected as current conditions establishing the baseline. The baseline conditions were based on the observations of ECCC weather stations. The climate projections of the 2050s cover the 30-year period from 2041 to 2070, and the 2080s cover the 30-year period from 2071 to 2100.

There are five ECCC weather stations in the region of Gingolx with data records providing recent historical data, and three stations with data that are sufficient for climate analysis. A summary of the weather stations with the most complete historical datasets is shown in Figure 7.1–3 and Table 7.1–1.

In consideration of data availability and the location of the Project, the Green Island (Station ID: 1063298) and Prince Rupert A (Station ID: 1066481) weather stations were chosen as the primarily weather stations to represent the climate baseline of Project area and was supplemented as necessary with data from the other weather stations.

Future climate projections are based on the CMIP5 climate projections data. There are nearly 40 GCMs that have contributed to CMIP5, which forms the basis of the *Fifth Assessment Report* and other recent publications from the IPCC. The Pacific Climate Impacts Consortium (PCIC) uses a subset of 28 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 downscaled climate projections under the RCP 8.5 emission scenario were used for the Project area.

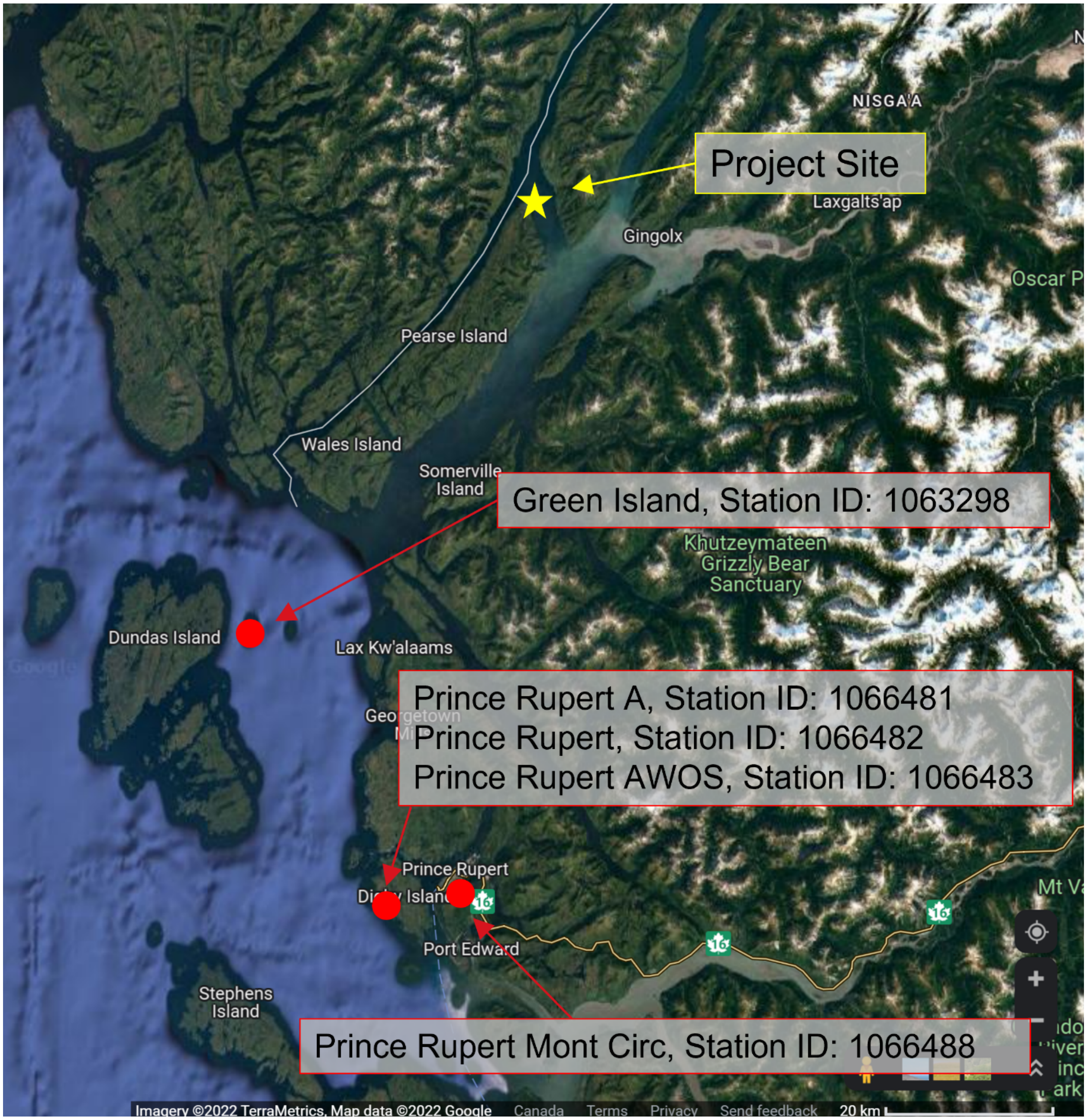


Figure 7.1–3 Historical Weather Stations in the Region of Gingolx (Source: Google Maps 2022)

Table 7.1–1 Summary of Weather Monitoring Stations in the Region of Gingolx

Weather Monitoring Station	Latitude	Longitude	Station ID	Data Range (Daily) [% of Data Available]	Elevation	Approximate Distance from the Project Site
Green Island	54°34'07.020" N	130°42'29.020" W	1063298	1981-2022 [99.8% (Temperature) 99.9% (Precipitation) 99.9% (Snow)]	11.9 m	60.89 km
Prince Rupert A	54°17'33.000" N	130°26'41.000" W	1066481	1962-2006 [99.4% (Temperature) 99.5% (Precipitation) 98.7% (Snow) 73.7% (Daily Wind)]	35.4 m	83.12 km
Prince Rupert	54°17'10.000" N	130°26'41.000" W	1066482	2010-2022 [95.2% (Temperature) 94.9% (Precipitation) 82.5% (Daily Wind)]	35.4 m	83.82 km
Prince Rupert AWOS	54°17'10.000" N	130°26'41.000" W	1066483	2005-2012 [98.8% (Temperature) 97.9% (Precipitation) 54.0% (Daily Wind)]	35.4 m	83.82 km
Prince Rupert Mont Circ	54°19'13.000" N	130°17'24.000" W	1066488	1959-2022 [95.7% (Precipitation) 95.7% (Snow)]	60.0 m	78.60 km

7.1.4.2 Climate of the Project Area

The Project Site is located on British Columbia's north coast at Wil Milit, which is north of Prince Rupert, BC and approximately 15 km east of Gingolx. British Columbia's north coast is 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 considerable snow at higher elevations. The coastal climate results in mild winters and cool summers. Winds are predominately from the south/southeast in Hecate Strait (between Haida Gwaii and mainland BC). Winds in Portland Canal, however, will be strongly influenced by topography. Marine waters in the vicinity of the Site are strongly tidal (range approximately seven metres above chart datum). Marine currents within Portland Inlet, Portland and Pearse Canals are highly variable due to a combination of wind and tidal forcing (KSI LISIMS LNG 2022).

The climate trends and projections for the Project area are presented below:

- Under future climate, warming temperatures are projected in all seasons, with the strongest warming trends during the winter season and for minimum temperatures. The frequency of cold days (days with a minimum temperature of -15°C or colder) is projected to decrease, declining from annual event to a rare event by the 2080s. Alternatively, the frequency of hot days (days with a maximum temperature of 30°C or greater) is projected to increase from a rare event in the current climate to annual event in the mid to late century. A similar trend to frequency of hot days is also projected for the frequency of heat waves (three or more consecutive days with a temperature of 30°C or greater).
- Total precipitation is projected to increase under future climate. Short duration high intensity extreme rainfall events are also projected to become frequent and intense under a warming climate. While total annual snowfall is projected to decrease, heavy snowstorm events are likely to continue to occur on a regular basis, though at a slightly reduced frequency.
- High winds (wind gusts of 90 kilometres per hour (**km/hr**) or greater) can occur on an annual basis and the frequency of these events is likely to remain steady or slightly increase under future climate.
- Relative sea level for Prince Rupert and the Portland Canal region is projected to rise by approximately 50–75 centimetre (**cm**) by 2100 under the RCP 8.5 emissions scenario.

7.1.5 Identification of Climate Hazards

Climate hazards are the climate variables that can impact the Project infrastructure components. The climate hazards used for this resilience assessment were chosen based on experience with previous climate change resilience studies for similar types of Project 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 increased maintenance requirements of infrastructure components and increased discomfort for personnel.
- Freeze-thaw cycles, which can increase maintenance requirements for walkways, roadways, and can increase slip and fall risks for personnel.
- Short duration high intensity rainfall, which can cause local flooding, can lead to structural damage of the infrastructure components, and can result in increased maintenance requirements.
- Heavy snowfall, which can impact the surface conditions of decks, platforms, and roadways and can result in increased maintenance costs for snow clearing.
- Extreme winds, which can lead to the structural damages to the Project or reduce facility operations or Site access.
- Sea level rise, which can lead to flooding of infrastructure assets.
- Lightning (as a proxy of wildfire), which can lead to the structural damages to the Project or reduce facility operations or Site access.

The climate variables selected for this resilience assessment are shown in Table 7.1–2. Once the climate variables are determined, a threshold value is chosen for each climate variable. The threshold value is normally associated with a consequence or effect on an infrastructure asset and helps establish the likelihood (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. The historical climate for the Project Site was characterized by the observations from ECCC weather stations. Future climate for the region were retrieved from climate projections produced by GCMs.

Table 7.1–2 also presents the confidence level associated with the projections for each climate variable. Confidence levels are based upon climate model ability to distinctly represent projected values of each of the variables should be noted that physical understanding of processes and trends may be stronger than what the models may produce analytically. Projections based on both GCMs and regionally downscaled models are considered with:

- Higher confidence for general temperature and precipitation projections, and sea level rise
- Moderate confidence for extreme parameters (e.g., precipitation extremes)
- Lower confidence for high wind events
- Low confidence for combined or complex events such as lightning

Combined or complex events are inferred based on other parameters, resulting in lower confidence for projections of combined event parameters. Confidence may also refer to whether other studies have been done for the climate events projections in the geographical area.

Table 7.1–2 Climate Variables Selected for Resilience Assessment (2050s Time Horizon)

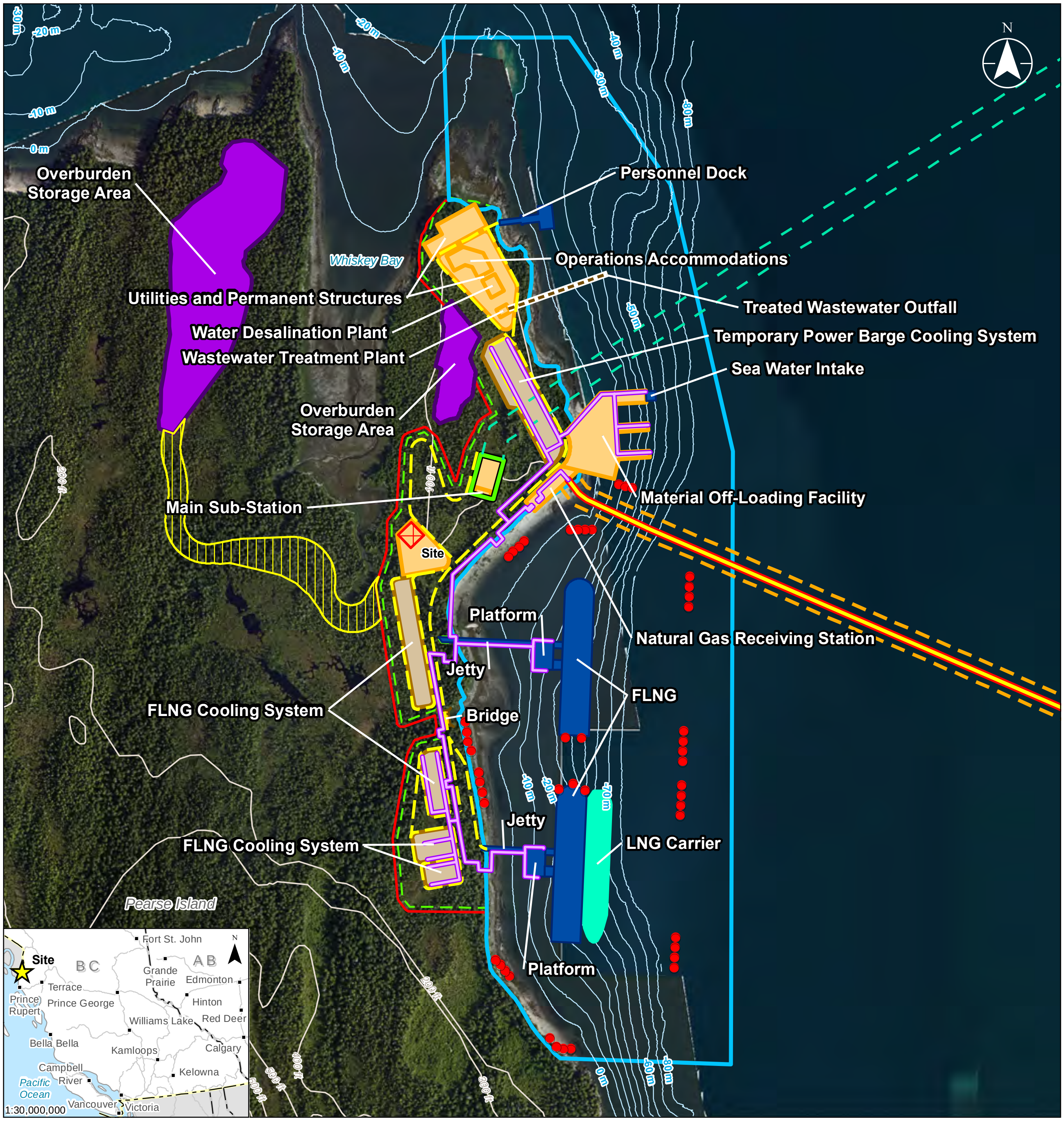
Climate Variable	Threshold	Trend	Confidence Level
Temperature			
High temperature extremes	Days (per year) with maximum temperature greater than or equal to 30°C	Increasing	High
Heat Waves	Three or more consecutive days with temperature greater than 30°C	Increasing	High
Cold Days	Days (per year) with min temps less than or equal to -15°C	Decreasing	High
Freeze-Thaw Cycles	Occurrence of 30 freeze-thaw cycles per year	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 millimetres (**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
Wind			
Wind gusts	Wind gusts greater than or equal to 90 kilometre per hour (**km/hr**)	Steady or Slightly Increasing	Low
Wind gusts	Wind gusts greater than or equal to 120 km/hr	Steady or Slightly Increasing	Low
Other			
Lightning (as a proxy of wildfire)	Change from baseline average, flash density per square kilometre, per year	Slightly Increasing	Low
Relative Sea Level Rise	Relative sea level rise exceeds 50 cm	Increasing	High

7.1.6 Assets under Assessment

The Project infrastructure assets and systems were grouped into the categories presented in Table 7.1–3. The list of assets and systems considered were based on Project description information provided by in the Detailed Project Description. The Project layout for the Base Case scenario (planned with a BC Hydro grid connection) is shown in Figure 7.1–4.

Table 7.1–3 List of Project Components Being Assessed

Asset	Infrastructure Category	Infrastructure Element
Floating Liquefied Natural Gas (FLNG) Units	Vessels	Mooring Lines
		Deck
	System and Equipment	Emergency Flare System
		Processing Equipment
Jetties and Platforms	Jetties and Platforms	Deck
		Foundation
Terrestrial FLNG Cooling System	FLNG Cooling System	FLNG Cooling System
Electrical/Distribution System	Substations	Substations and Distribution Equipment
	Backup/Emergency Power Generation	Diesel Power Generators
	Fuel Storage Tanks	Diesel Fuel Storage Tanks
Feed Gas Piping	Feed Gas Piping	Natural Gas Receiving Station
		Feed Gas Piping
		Utility Piping Lines
Material Off-Loading Facility	Material Off-Loading Facility	Material Off-Loading Facility
Water and Wastewater Management Facilities	Desalination Plant	Plant Equipment, Sea Water Intake
	Wastewater Treatment Plant	Plant Equipment, Treated Wastewater Outfall
	Stormwater Management	Drainage System (Catch basins, Ditches, Pipes)
Site Access	Helipad	Helipad
	Access Roads	Access Roads
		Bridges
		Security Fencing
Buildings	Operation Accommodations and Control/ Administrative/ Maintenance/ Security Buildings	Envelope
		Roof
		Foundation
		Heating and Cooling System
		Utility Connections
Telecommunication	Telecommunication	Telecommunication (Tower)
Other Utilities	Third Party Utilities	Power Supply



Mooring Anchor	
Proposed Access Road	
Feed Gas Pipeline	
Feed Gas Pipeline Right-of-Way	
Powerline Right-of-Way from Mainland	
Utility Line	
Wastewater Treated Effluent Pipeline	
Preliminary Site Fenceline	
Terrestrial Footprint	

Footprint Component

- Access Corridor
- Bridge
- Buildings and Utilities
- Cooling Structures
- Helicopter Pad
- Marine Component (Fixed)
- Marine Component (Not Fixed)
- Marine Footprint
- Overburden Storage Area
- Switchyard
- Bathymetric Contour

0 75 150 225 300 375 m

1:12,500 (at original document size of 8.5x11)

KSI LISIMS LNG

Notes
1. Coordinate System: NAD 1983 UTM Zone 9N
2. Data Sources: DataBC, Government of British Columbia; Natural Resources Canada
3. Source: Esri, Maxar, Earthstar Geographics, and the GIS User Community

Stantec

Project Location: Pearse Island, BC

Project Number: 123221820
Prepared by AYIU on 20240603
Requested by JFRIES on 20240603
Checked by EFLORY on 20240603

Client/Project/Report
Ksi Lisims LNG
Natural Gas Liquefaction and Marine Terminal
Strategic Assessment of Climate Change

Figure No.
7.1-4

Title
Ksi Lisims LNG Conceptual Project Layout – Base Case

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7.1.7 Consequence of Impact

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 7.1–4. The interactions of climate variables with the Project infrastructure components may result in cascading climate impacts on the natural environment including air, freshwater, marine water, groundwater, vegetation and wetland, fish and wildlife habitats. The consequences of cascading climate impacts on natural environment were assessed qualitatively and were not included in consequence of impact criteria in Table 7.1–4.

Table 7.1–4 Consequence of Impact Criteria

Consequence Category	Description	Examples
Structural Integrity	Climate change may reduce a structure's/equipment's ability to withstand loads without failing or deforming and may exacerbate wear.	• Infrastructure failure • Infrastructure deterioration • Increased loading and/or stress • Change in material performance
Operations & Maintenance (**O&M**)	Climate change may impact the ability of O&M staff to access the worksite for maintenance or require updates to occupational health and safety procedures in maintaining safe access to worksites. Impacts from climate change result in an increase in O&M costs.	• Revisions to occupational health and safety procedures • Reduced serviceability • Increased maintenance / replacement cycles and frequencies • Increased operation and maintenance costs • Increased health and safety hazards • Change in operational performance
Functionality	Climate change may impact the ability of the infrastructure system or component to function at its designed capacity.	• Infrastructure operates below design capacity (e.g., plugged culverts) • Service provided by infrastructure is reduced or ineffective to address climate impacts. • Temporary or permanent loss of service • Reduction in service or service quality

7.1.8 Consequence of Climate Impacts on Assets

The potential impacts from both extreme events and incremental or slow onset climate hazards on Project assets are presented in Table 7.1–5. The climate hazards, such as wildfire and sea level rise, may impact most of the infrastructure components throughout the life of the Project. The consequences of these climate hazards are assessed qualitatively in this assessment.

Table 7.1–5 Potential Climate Impacts on Project Assets

Climate Variable	Infrastructure Category	Infrastructure Element Impacted	Description of Interaction
Extreme Heat/ Heat Waves	FLNG Units	• Vessels – Deck • System and Equipment – Processing Equipment	• Extreme heat may cause discomfort for personnel. • Extreme heat may impact the efficiencies of the processing equipment.
	Jetties and Platforms	• Deck	• Extreme heat may cause discomfort for personnel.
	FLNG Cooling System	• FLNG Cooling System	• Extreme heat may impact the efficiencies of the system.
	Electrical/ Distribution System	• Substation	• Extreme heat may overload the substation equipment resulting in reduced efficiencies.
		• Diesel Power Generators	• Extreme heat may impact the efficiencies of the system.
	Feed Gas Piping	• Natural Gas Receiving Station	• Extreme heat may cause discomfort for personnel.
	Material Off-Loading Facility	• Material Off-Loading Facility	• Extreme heat may cause discomfort for personnel.
	Operation Accommodations and Control/ Administrative/ Maintenance/ Security Buildings	• Heating and Cooling System	• Overloading the cooling system resulting in increased utility costs.
Heating Degree Days	Operation Accommodations and Control/ Administrative/ Maintenance/ Security Buildings	• Heating and Cooling System	• Overloading the heating system resulting in increased utility costs.

Table 7.1–5 Potential Climate Impacts on Project Assets

Climate Variable	Infrastructure Category	Infrastructure Element Impacted	Description of Interaction
Cooling Degree Days	FLNG Cooling System	• FLNG Cooling System	• Overloading the cooling system may result in reduced efficiencies.
	Operation Accommodations and Control/ Administrative/ Maintenance/ Security Buildings	• Heating and Cooling System	• Overloading the cooling system resulting in increased utility costs.
Cold Days	FLNG Units	• Vessels – Deck	• Cold temperature may cause discomfort for personnel.
	Jetties and Platforms	• Deck	
	Feed Gas Piping	• Natural Gas Receiving Station	
	Material Off-Loading Facility	• Material Off-Loading Facility	
Cold Days	Water and Wastewater Management Facilities	• Stormwater Management – Drainage System (Catch basins, Ditches, Pipes) • Water and wastewater treatment piping and equipment	• Cold temperature may cause freezing and damage and/or reduce the functionality of water supply and drainage systems.
	Operation Accommodations and Control/ Administrative/ Maintenance/ Security Buildings	• Heating and Cooling System	• Improper sizing of heating system can cause increased utility costs and lower occupant comfort.

Table 7.1–5 Potential Climate Impacts on Project Assets

Climate Variable	Infrastructure Category	Infrastructure Element Impacted	Description of Interaction
Freeze-thaw cycles	FLNG Units	• Vessels – Deck	• Freezing and thawing could cause safety issues (slip and fall) for personnel.
	Jetties and Platforms	• Deck	
	Feed Gas Piping	• Natural Gas Receiving Station	
	Material Off-Loading Facility	• Material Off-Loading Facility	
	Water and Wastewater Management Facilities	• Stormwater Management - Drainage System (Catch basins, Ditches, Pipes) • Water and wastewater piping and equipment	• Freeze thaw cycles may impact the functionality of water- water supply and wastewater management systems.
	Site Access	• Helipad	• Freezing and thawing could cause safety issues (slip and fall) for personnel. • Freezing conditions could cause safety issues for vehicles.
		• Access Roads	
		• Bridge	
	Operation Accommodations and Control/ Administrative/ Maintenance/ Security Buildings	• Foundation	• Freeze thaw cycles may cause cracks and spalling in concrete.
Short duration high intensity rainfall/ Long duration rainfall	FLNG Units	• Vessels – Deck	• High intensity rain may overwhelm the drainage systems resulting in slow drainage of excess water.
	Jetties and Platforms	• Deck	
	Feed Gas Piping	• Natural Gas Receiving Station	
	Material Off-Loading Facility	• Material Off-Loading Facility	

Table 7.1–5 Potential Climate Impacts on Project Assets

Climate Variable	Infrastructure Category	Infrastructure Element Impacted	Description of Interaction
	Water and Wastewater Management Facilities	• Stormwater Management – Drainage System (Catch basins, Ditches, Pipes) • Desalination Plant – Sea Water Intake and Plant Equipment	• High intensity rain may increase runoff and overwhelm the stormwater drainage system resulting in local flooding. • High intensity rain may cause extra strain on the stormwater systems at the sites and reduce the functionality of drainage ditches. • High intensity rain may result in increased sedimentation into surface water resulting in increase suspended sediment intake
Short duration high intensity rainfall/ Long duration rainfall	Site Access	• Helipad	• High intensity rain may result in local flooding, reducing access to critical roads and other infrastructure.
		• Access Roads and Bridges	
	Operation Accommodations and Control/ Administrative/ Maintenance/ Security Buildings	• Roof	• High intensity rain may overwhelm the roof gutter and downspouts leading to overflow and local flooding.
		• Foundation	• High intensity rain may cause erosion of soils around the foundation and impact its integrity.

Table 7.1–5 Potential Climate Impacts on Project Assets

<table>
<tr><th>Climate Variable</th><th>Infrastructure Category</th><th>Infrastructure Element Impacted</th><th>Description of Interaction</th></tr>
<tr><td rowspan="9">Heavy Snowfall</td><td>FLNG Units</td><td>• Vessels – Deck</td><td rowspan="4">• Heavy snow may impact the surface conditions of deck resulting in increased snow clearing requirements.
• Heavy snow could cause safety issues for personnel (slip and fall).
• Heavy snow could restrict access to areas and equipment requiring routine maintenance.</td></tr>
<tr><td>Jetties and Platforms</td><td>• Deck</td></tr>
<tr><td>Feed Gas Piping</td><td>• Natural Gas Receiving Station</td></tr>
<tr><td>Material Off-Loading Facility</td><td>• Material Off-Loading Facility</td></tr>
<tr><td rowspan="2">Electrical/ Distribution System</td><td>• Substation</td><td rowspan="2">• Heavy snow could restrict access to areas and equipment requiring routine maintenance.</td></tr>
<tr><td>• Diesel Fuel Storage Tanks</td></tr>
<tr><td>Water and Wastewater Management Facilities</td><td>• Stormwater Management - Drainage System (Catchbasins, Ditches, Pipes)
• Water and wastewater equipment and piping systems</td><td>• Heavy snow may block the catch basins resulting in increased snow clearing requirements.
• Heavy snow could restrict access to areas and equipment requiring routine maintenance.</td></tr>
<tr><td rowspan="2">Site Access</td><td>• Helipad</td><td rowspan="2">• Heavy snow may result in increased snow clearing and salting requirements.
• Heavy snow could cause safety issues for personnel (slip and fall).
• Heavy snow could cause safety issues for vehicular traffic.</td></tr>
<tr><td>• Access Roads</td></tr>
<tr><td rowspan="2">Heavy Snowfall (cont'd)</td><td>Operation Accommodations and Control/ Administrative/ Maintenance/ Security Buildings</td><td>• Roof</td><td>• Heavy snow may exceed the bearing capacity of roofs.
• Heavy snow falling from roofs could cause safety issues for personnel.</td></tr>
<tr><td>Third Party Utilities</td><td>• Power Supply</td><td>• Increased requirement for emergency power due to power outages.
• Inability to operate the facility due to power outages.</td></tr>
</table>

Table 7.1–5 Potential Climate Impacts on Project Assets

Climate Variable	Infrastructure Category	Infrastructure Element Impacted	Description of Interaction
High Wind Gusts	FLNG Units	• Vessels – Mooring Lines	• High wind gusts may cause structural damage to the mooring lines resulting in repair/ replacement or a safety issue with the FLNGs. • High wind gusts may preclude the ability of LNGCs to moor, resulting in production interruptions.
		• Vessels – Deck	• High wind speed may cause safety issues for personnel.
		• Emergency Flare System	• High wind speed may cause damage to the flare stack.
	Jetties and Platforms	• Deck	• High wind speed may cause damage to the deck-mounted systems and cause safety issues for personnel.
	Material Off-Loading Facility	• Material Off-Loading Facility	• High wind speed may cause safety issues for personnel. • High wind speed may cause delays in marine deliveries to the Site.
	Site Access	• Helipad	• High wind speeds may impact the helicopter landing and taking off activities resulting in the inability to evacuate a medical patient via medevac.
		• Access Road	• High wind speeds may cause debris to be blown resulting in increased maintenance requirements. • High wind speed may cause safety issues for personnel or vehicular traffic.
		• Security Fencing	• High wind speeds may cause damage to the security fencing.
	Operation Accommodations and Control/ Administrative/ Maintenance/ Security Buildings	• Envelope	• High wind speeds may cause damage to the building envelope and roof resulting in increased maintenance requirements.
		• Roof	
		• Utility Connections	• High wind speeds may cause damage to the utility connections resulting in reduced functionality.
	Telecommunication	• Telecommunication (Tower)	• High wind speeds may cause damage to the telecommunication tower.

Table 7.1–5 Potential Climate Impacts on Project Assets

Climate Variable	Infrastructure Category	Infrastructure Element Impacted	Description of Interaction
High Wind Gusts (cont'd)	Third Party Utilities	• Power Supply	• Increased requirement for emergency power due to power outages. • Inability to operate the facility due to power outages
Lightning (as a proxy of wildfire)	Electrical/ Distribution System	• Substations, Fuel Storage Tanks	• Wildfire may cause structural damage of infrastructure components. • Wildfire may result in closure of Site access. • Wildfire and smoke may cause health and safety issues for personnel and result in Site evacuation.
	Site Access	• Site Access	
	Operation Accommodations and Control/ Administrative/ Maintenance/ Security Buildings	• Envelope, Roof, Utility Connections	
	Telecommunication	• Telecommunication (Tower)	
	Third Party Utilities	• Power Supply	
Relative Sea Level Rise	Electrical/ Distribution System	• Substations	• Relative mean sea level rise may cause flooding at the Project Site resulting in more maintenance requirements of the exposed infrastructure components. • Relative mean sea level rise may cause flooding and interrupt or preclude operations of the facility
		• Diesel Fuel Storage Tanks	
	Water and Wastewater Management Facilities	• Desalination Plant	
		• Wastewater Treatment Plant	
	Site Access	• Helipad	
		• Access Roads	
	Operation Accommodations and Control/ Administrative/ Maintenance/ Security Buildings	• Envelope	

7.1.9 Climate Risk Analysis

Risk rating is defined as the product of two ratings as follows.

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 in the 2050s. 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 Project components is not considered in the selected lifespan of this assessment.

7.1.9.1 Likelihood Scores for Climate Variables

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 7.1–6. The likelihood score is assigned based on the evaluation of historical occurrences and future climate projections for each climate variable.

The likelihood ratings for the selected climate parameters are presented in Table 7.1–7.

Table 7.1–6 Likelihood Ratings Based on Climate Event Occurrence

Likelihood Rating	Qualitative Descriptor	Occurrence	Descriptor
1	Very Low	<1:50 year	Not likely to occur in assessment period
2	Low	1:30-50 year	Likely to occur once between 30-50 years
3	Moderate	1:10-30 year	Likely to occur once every 10 to 30 years
4	High	1: 1-10 year	Likely to occur at least once per decade
5	Very High	>1/year	Likely to occur once or more annually

Table 7.1–7 Current and Future Likelihood Rating for Selected Climate Variables

Climate Variable	Climate Threshold	Likelihood of Occurring		
		Baseline Climate	Future Climate Projections	
			2050s (2041-2070)	2080s (2071-2100)
Extreme heat	Annual occurrence of maximum daily temperature of 30°C or more	3	4	5
Heatwaves	Frequency of occurrence of heatwave events (three consecutive days or more with Tmax ≥30°C)	1	3	4
Heating Degree Days	Change from baseline average	5	4	3
Cooling Degree Days	Change from baseline average	3	4	5
Cold Days	Days (per year) with min temps less than or equal to -15°C	5	3	1
Freeze-thaw cycles	Occurrence of 30 freeze-thaw cycles per year	5	4	4
Long-duration rainfall	100 mm in 24 hours	4	5	5
Short-duration (high intensity) rainfall	50 mm in 1 hour	1	1	1
Snowfall	25 cm in 24 hours	4	4	3
High wind gusts	Wind gust events of 90 km/h or more	5	5	5
High wind gusts	Wind gust events of 120 km/h or more	3	4	4
Lightning (as a proxy of wildfire)*	Change from baseline average, flash density per square kilometre, per year	4	4	4
Relative sea level rise*	Relative sea level rise exceeds 50 cm	1	3	5
NOTE: * Climate Risks are assessed qualitatively				

7.1.9.2 Consequence Score of Climate Impacts

The consequence ratings used for this assessment are described in Table 7.1–8. The ratings are based on the degree to which a climate variable can impact the infrastructure/asset or infrastructure component resulting in a loss or disruption of service. Service in the context of the Project infrastructure is defined as the various offerings and functions provided by the Project infrastructure components. As an example, for access roads, a minor rating from high intensity rainfall might mean temporary local flooding and/or no loss of service while a high rating may reflect significant flooding resulting in the roads being closed for a period of time.

Table 7.1–8 Consequence Ratings

Consequence Rating	Qualitative Descriptor	Structural	Operations and Maintenance	Functional
1	Very Low	• Little or no damage to infrastructure.	• Can be corrected during regular maintenance. • Little or no impact to O&M budgets. • Little or no impact on health & safety	• No serious impact from a weather event; Site accessible; no loss of service
2	Low	• Some extra costs to repair; costs are within O&M budgets.	• Operational costs may increase by a small amount. Repairs can be corrected with existing O&M resources. • Minor health & safety implications that can be addressed by standard operational plans and procedures	• Infrastructure still operable with minor reduction on functionality; Site accessible with possible delays.
3	Moderate	• Some damage to infrastructure; repair costs may exceed planned O&M budgets. • Some specialized labour or equipment required to complete repairs. • Repairs/replacement takes several days weeks to correct.	• Operational costs may increase by a modest amount. • Additional time and resources above normal staffing levels required. • May require outside /specialty contractors to correct. • Some health & safety concerns may require medical attention and may require changes in operational policies/procedures to address the impacts.	• Some loss of service; temporary disruption of service requiring intervention actions. • Site access is reduced but not stopped.
4	High	• Significant damage to infrastructure; impacts/damage require a large cost to repair/replace components. • Costs exceed planned O&M budget. Requires additional funding and outside resources to correct. • Repair/replacement takes weeks to months to correct.	• Costs exceed O&M budget by significant amount. • Additional maintenance using additional resources and outside assistance is required to address damage. • Major health & safety concerns that may require urgent medical attention and may require changes in operational policies/procedures to address the impacts.	• Major loss of service; extended period (hours to days) of service disruptions. • Site access and supporting utilities likely to be interrupted.

Table 7.1–8 Consequence Ratings

Consequence Rating	Qualitative Descriptor	Structural	Operations and Maintenance	Functional
5	Very High	• Impact/damages result in loss or significant destruction of infrastructure or materials. • Extended time (months) required to repair/restore structure and materials. • Costs are high and may require special funding/ approvals.	• System/components require upgrades/replacement due to inability to replace individual components. • May take months to repair/restore system/components. • Major health & safety concerns leading to permanent incapacity. Large numbers of individuals impacted.	• Significant disruptions to the service. • May require emergency planning responses. • Access to Site is severely impacted or Site is not accessible.

7.1.9.3 Risk Analysis Procedure

Using the equation "Risk Rating = Likelihood Rating x Consequence Rating" provides numerical risk ratings from 1-25 as shown in Figure 7.1–5.

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				

Figure 7.1–5 Risk Ratings – Evaluation Matrix Adapted from Climate Lens General Guidance (Infrastructure Canada 2019)

In Table 7.1–9, risk ratings are explained with suggested risk treatments as per the Climate Lens General Guidance.

Table 7.1–9 Risk Classification. Adapted from Climate Lens General Guidance v1.2

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	3,4,6	• Minor asset/equipment damage. • Minor service disruption may be possible. • No permanent damage. • Minor repairs or restoration expected.	Controls likely, but not required.
Moderate	5,8,9	• 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.

7.1.9.4 Risk Analysis Results and Adaptation Considerations

Climate risks for the current and future climate in the 2050s were assessed for the Project infrastructure components. A summary of the fraction of different risks for the current and future climate is shown in Table 7.1–10. There were no Extreme (or Very High) risks identified in the assessment. Many of the climate risks were rated as low risks for both the current (49.4%) and future (36.9%) climate. The “high” risks (risks in the high category) decrease from 19.4% under current climate to 17.5% under future climate in 2050s. The percentage decreases in “high” risks were associated with the decreasing trends of heating degree days, extreme cold, and freeze-thaw cycles. The majority of the high climate risks for the current and future climate were associated with high wind gusts. A summary of the moderate and high risks, including potential adaptation measures to be considered during facility design, is shown in Table 7.1–11.

Snowfall was found to be a “moderate” risk for the current and future climate. Freeze-thaw cycles caused “high” risks for current climate but is expected to be “moderate” risks in the future as freeze-thaw cycles are expected to decline in the future. Heating degree-days caused “high” risks for the building heating system in current climate and declined to “moderate” risks in future climate through substantial changes to the potential heating requirements for the buildings.

Table 7.1–10 Distribution of Risk Levels for Climate Change Resilience Assessment

Risk Level	Fraction of Total Risk Count (%)	
	Current Climate	**Future Climate (2050s)**
Extreme	0.0	0.0
High	19.4	17.5
Moderate	13.8	35.0
Low	49.4	36.9
Negligible	17.5	10.6
Total	**100**	**100**

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Table 7.1–11 Summary of Moderate and High Risks for Current and Future Climate, and Climate Adaptation Considerations

Climate Variable	Infrastructure Element	Description of Climate-Asset Interaction	Current Risk Rating	Future Risk Rating	Adaptation Considerations
Heating Degree Days [Change from current conditions]	Buildings – Heating System	• Overloading to the heating system resulting in increased utility costs.	10	8↓	• Consider high performance insulation and glazing, including higher solar heat gain coefficient fenestration, and low-e coatings to reduce rate of heat transfer through building structures and reduce heating and cooling loads.
Cold Days [Days (per year) with min temps less than or equal to -15°C]	Stormwater Management - Drainage System (Catchbasins, Ditches, Pipes)	• Cold temperature may cause freezing and damage and/or reduce the functionality of water supply and management systems	10	6↓	• Develop O&M policies around regular maintenance inspections to identify any issues with the water supply and management system.
	Water and Wastewater Management Facilities -Water and wastewater equipment and piping systems		5	3↓	
Freeze-thaw cycles [Occurrence of 30 freeze-thaw cycles per year]	FLNG Units (Vessels – Deck) Jetties and Platforms – Deck Natural Gas Receiving Station Material Off-Loading Facility	• Freezing and thawing could cause safety issues (slip and fall) for personnel.	10	8↓	• Consider de-icing treatment for deck/ surface during the freeze-thaw events. • Consider the health and safety of the staff / personnel through the development of a health and safety plan that includes risks associated with freeze-thaw.
	Stormwater Management – Drainage System (Catchbasins, Ditches, Pipes)	• Freeze thaw cycles may impact the functionality of ditches.	10	8↓	• Conduct annual inspection program to identify any issues early.
	Site Access – Helipad Site Access – Access Roads Site Access – Bridge	• Freezing and thawing could cause safety issues (slip and fall) for the personnel.	10	8↓	• Consider sanding/ salting treatment for the paved surface during the freeze-thaw events. • Consider the health and safety of the staff / personnel through the development of a health and safety plan that includes risks associated with freeze-thaw.
High Intensity rainfall	Buildings – Roof	• High intensity rain may overwhelm the roof gutter and downspouts leading to local flooding.	8	10↑	• Ensure Intensity duration frequency (IDF) curves under future climate is considered in roof design. • Conduct annual inspection program to identify any clogging of the gutter system early. • Develop O&M policies around regular inspections and cleaning of the gutters and downspouts.
Heavy Snowfall [25 cm in 24 hours]	FLNG Units (Vessels – Deck) Jetties and Platforms – Deck Natural Gas Receiving Station Material Off-Loading Facility	• Heavy snow could cause safety issues for the personnel (slip and fall).	8	8	• Develop O&M policies for clearing of snow to reduce slip and fall concerns. • Consider installation of snow/ice melting system to reduce ice buildup.
	Water and Wastewater Management Facilities – Water and wastewater equipment and piping systems	• Heavy snow could restrict access to areas and equipment requiring routine maintenance.	8	8	• Develop O&M policies for clearing of snow.
	Site Access – Helipad Site Access – Access Road	• Heavy snow may result in increased snow clearing and salting requirements. • Heavy snow could cause safety issues for the personnel (slip and fall).	8	8	• Develop O&M policies for clearing of snow to reduce slip and fall concerns.
	Third Party Utilities – Power Supply	• Increased requirement for emergency power due to power outages.	8	8	• Ensure emergency generator is available to provide power during power outages.

Table 7.1–11 Summary of Moderate and High Risks for Current and Future Climate, and Climate Adaptation Considerations

Climate Variable	Infrastructure Element	Description of Climate-Asset Interaction	Current Risk Rating	Future Risk Rating	Adaptation Considerations
High Wind Gusts [Wind gust events of 90 km/h or more]	FLNG Units (Vessels – Mooring Lines)	• High wind gusts may cause structural damage to the mooring lines resulting in repair/ replacement.	10	10	• Ensure the changes in frequency of wind gusts and associated tidal currents under future climate conditions are considered during design of mooring lines. • Develop proactive inspection program of the mooring equipment after the high wind events to address damages quickly.
	FLNG Units (Vessels – Deck) Material Off-Loading Facility	• High wind speed may cause safety issues for the personnel.	10	10	• Consider the health and safety of the staff / personnel through the development of a health and safety plan that includes risks associated with high wind gusts events.
High Wind Gusts [Wind gust events of 90 km/h or more]	Site Access – Helipad	• High wind speeds may impact the helicopter landing and taking off activities resulting in the inability to evacuate a medical patient.	10	10	• Establish clear communications protocols for helicopter operations in high wind gusts events. • Consider having a medical clinic at Site with the ability to stabilize trauma patients until such time as they can be evacuated safely.
	Site Access – Access Road	• High wind speeds may cause debris to be blown resulting in increased maintenance requirements. • High wind speed may cause safety issues for the personnel.	10	10	• Develop O&M policies around regular maintenance including inspection and clearing (e.g., debris) after each severe climate event. • Consider the health and safety of the staff through the development of a health and safety training that includes risks associated with the working during high wind events.
	Buildings – Envelope, Roof	• High wind speeds may cause damage to the building envelope and roof resulting in increased maintenance requirements.	10	10	• Ensure building envelope and roof are designed considering the high frequency wind gusts events.
	Telecommunication (Tower)	• High wind speeds may cause damage to the telecommunication tower.	10	10	• Develop emergency operational plan during high wind events.
	Third Party Utilities – Power Supply	• Increased requirement for emergency power due to power outages.	10	10	• Ensure emergency generator is available to provide power during power outages.
High Wind Gusts [Wind gust events of 120 km/h or more]	FLNG Units (Vessels – Mooring Lines)	• High wind gusts may cause structural damage to the mooring lines resulting in repair/ replacement.	9	12↑	• Ensure the changes in frequency of wind gusts and associated tidal currents under future climate conditions are considered during design of mooring lines. • Develop proactive inspection program of the mooring equipment after the high wind events to address damages quickly.
High Wind Gusts [Wind gust events of 120 km/h or more]	Site Access – Helipad	• High wind speeds may impact the helicopter landing and taking off activities resulting in inability to evacuate a medical patient.	9	12↑	• Establish clear communications protocols for helicopter operations in high wind gusts events. • Consider having a medical clinic at Site with the ability to stabilize trauma patients until such time as they can be evacuated safely.
	Site Access – Access Road	• High wind speeds may cause debris to be blown resulting in increased maintenance requirements. • High wind speed may cause safety issues for the personnel.	9	12↑	• Develop O&M policies around regular maintenance including inspection and clearing (e.g., debris) after each severe climate event. • Consider the health and safety of the staff through the development of a health and safety training that includes risks associated with the working during high wind events.
	Buildings – Envelope, Roof	• High wind speeds may cause damage to the building envelope and roof resulting in increased maintenance requirements.	9	12↑	• Ensure building envelope and roof are designed considering the high frequency wind gusts events. • Consider installation of hurricane clips to securely fasten roof framing to support structures.

Table 7.1–11 Summary of Moderate and High Risks for Current and Future Climate, and Climate Adaptation Considerations

<table>
<tr><th>Climate Variable</th><th>Infrastructure Element</th><th>Description of Climate-Asset Interaction</th><th>Current Risk Rating</th><th>Future Risk Rating</th><th>Adaptation Considerations</th></tr>
<tr><td rowspan="5">Lightning (as a proxy of wildfire) [Change from baseline average, flash density per square kilometre, per year]</td><td>Substation, Fuel Storage Tanks</td><td rowspan="5">• Wildfire may cause structural damage of infrastructure components.
• Wildfire may result in closure of Site access.
• Wildfire and smoke may cause health and safety issues for the personnel and result in Site evacuation.</td><td colspan="2" rowspan="5">Qualitatively assessed risk – Slightly increasing trend</td><td rowspan="5">• Develop emergency response plan including clear communications protocols for Project operations should a wildfire event occur.
• Develop a health and safety plan for staff that includes risks associated with poor air quality.</td></tr>
<tr><td>Site Access</td></tr>
<tr><td>Envelope, Roof, Utility Connections</td></tr>
<tr><td>Telecommunication (Tower)</td></tr>
<tr><td>Third Party Utilities - Power Supply</td></tr>
<tr><td rowspan="7">Relative sea level rise [Relative sea level rise exceeds 50 cm]</td><td>Substation</td><td rowspan="7">• Relative mean sea level rise may cause flooding at the Project Site resulting in more maintenance requirements of the exposed infrastructure components.
• Relative mean sea level rise may cause flooding and damage to the building foundation.</td><td colspan="2" rowspan="7">Qualitatively assessed risk – Increasing trend
Qualitatively assessed risk – Increasing trend</td><td rowspan="7">• Ensure design elevation of infrastructure foundation considers predicted sea level rise to minimize the impacts of flooding.
• Ensure location of infrastructure considers the predicted sea level rise inundation areas.</td></tr>
<tr><td>Diesel Fuel Storage Tanks</td></tr>
<tr><td>Desalination Plant</td></tr>
<tr><td>Wastewater Treatment Plant</td></tr>
<tr><td>Helipad</td></tr>
<tr><td>Access Road</td></tr>
<tr><td>Foundation</td></tr>
</table>

7.1.9.5 Highest Risks

The climate variables that presented the highest risks to the Project are heating degree days, cold days, freeze-thaw cycles, long duration rainfall, heavy snowfall, and high wind events. The highest risks identified for the Project are summarized below:

- Heating degree days resulted in "high" risks to the building heating system under current climate and declining to "moderate" risks in 2050s due to decreasing trend in cold temperature.
- Cold days resulted in "high" risks to the stormwater drainage system and decline to "low" risks in 2050s due to decreasing trend in cold temperature.
- Freeze-thaw cycles may cause safety issues (slip and fall) for personnel resulting in "high" risks under current climate, declining to "moderate" risks in 2050s due to decreasing trend in freeze-thaw cycles.
- High intensity rainfall may cause the roof gutter system to overflow and cause localized flooding. The risks for the building roof due to high intensity rainfall changed from "moderate" under current climate to "high" in the 2050s.
- Heavy snowfall may cause increased snow clearing requirements and resulted in "moderate" risks in current climate and in 2050s for access roads, helipad, and power supply. Heavy snowfall could also cause safety issues (slip and fall) for personnel and resulted in "moderate" risks in both current climate and 2050s.
- High wind gusts (wind gust events of 90 km/h or more) may cause structural damage to the mooring lines, building envelope/ roof, or the telecommunication tower resulting in "high" risk in current climate and in 2050s. High wind speeds may cause safety issues for personnel and resulted in "high" risks in 2050s.
- High wind gusts (wind gust events of 90 km/h or more) may impact the helicopter landing and taking off resulting in "high" risks under current climate and in 2050s.
- High wind gusts may cause power failures and increased requirement for emergency power resulting in "high" risk in current climate and in 2050s.

It is important to note that the climate change impacts risk profile is a prioritization of impacts relative to each other, not against an external benchmark. Designations of "high", and "moderate" risks should be considered in the context that many risks can be addressed by considering climate adjusted design criteria for future climate conditions and by adjusting O&M policies and procedures as needed.

7.1.9.6 Climate Impacts on Environment

High intensity rainfall can cause damage to Project infrastructure components (e.g., access roads and bridges) through erosion resulting in increased risks of sedimentation into surface waters.

Large waves associated with high wind events can cause shoreline erosion and damage to the mooring systems resulting in increased risks of contamination from FLNG facility if a system failure occurs.

The climate risks associated with wind gusts ≥ 120 km/hr can increase the risk of spreading contaminated surface materials.

Wildfire may cause structural damage of infrastructure components and result in increased risks of contamination into air, land, and water systems.

Sea level rise may cause flooding and erosion at the Project Site resulting in increased risks of sedimentation into surface water.

The increased risks of contamination to the environment associated with extreme high temperature, high intensity rainfall, high wind events, wildfire, and sea level rise under future climate conditions could impact the marine life and wildlife habitats.

7.1.10 Consideration of Resilience Principles in Climate Change Resilience Assessment

The following climate change resilience principles have been incorporated into this assessment as recommended by the Climate Lens – General Guidance v.1.2.

7.1.10.1 Proportionate Assessment

The analysis and recommendations in this CCRA are based on information available within the timeline and scope of this Project, as well as experience with other 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.

7.1.10.2 Systemic Analysis of Risk

By using a CCRA methodology that conforms to ISO 31000:2018 Standard Risk Management—Principles and Guidelines, this CCRA is considered a high-level risk identification and assessment that meets the requirements set by the Strategic Assessment of Climate Change (ECCC 2020; ECCC 2022b) and Infrastructure Canada's Climate Lens – General Guidance v1.2.

7.1.10.3 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 detail design stages of the Project and establishing 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 Project constructor takes future climate parameters into account and to establish effective O&M policies and practices that work for the Site in a changing climate.

7.1.10.4 Avoidance of Unintended Consequences

At the current stage of the Project, it is too early to fully consider the unintended consequences of risk transference or mitigation strategies, which can 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, design targets for the reduction of operational GHGs may be incorporated to avoid long-term unintended environmental consequences.

7.1.11 Description of Evidence Base

To anticipate the climate vulnerabilities for the Project infrastructure, this assessment relied on the review of similar assessments or adaptation plans completed by other agencies with similar infrastructure or with similar climate hazards, and discussions with expert staff advisors. The infrastructure responses and comments regarding the impact to each selected climate parameter are evaluated based on the professional judgement of the assessors, and a review of the following documents.

- Ksi Lisims LNG - Natural Gas Liquefaction and Marine Terminal DPD (2022)
- Strategic Climate Risk Assessment Framework for British Columbia – Developed in progress toward a Strategic Climate Risk Assessment for British Columbia (2019)
- Infrastructure Canada's Climate Lens – General Guidance v1.2 (https://www.infrastructure.gc.ca/pub/other-autre/cl-occ-eng.html)
- Draft Technical Guide related to the Strategic Assessment of Climate Change: Assessing Climate Change Resilience – Environment and Climate Change Canada (2022c) (https://www.strategicassessmentclimatechange.ca/)

7.1.11.1 Climate Data Sources

The study evaluated climate data from nearby ECCC weather stations. There are five ECCC weather stations in the region of Gingolx with data records providing recent historical data, and three stations with data that are sufficient for climate analysis. In consideration of data availability and the location of the Project, the Green Island (Station IS: 1063298) and Prince Rupert A (Station ID: 1066481) weather stations were chosen as the primarily weather stations to represent the climate baseline of the region of Gingolx and was supplemented as necessary with data from the other weather stations.

Future climate projections are based on the CMIP5 climate projections data. There are nearly 40 GCMs that have contributed to CMIP5, which forms the basis of the *Fifth Assessment Report* and other recent publications from the PCC. The Pacific Climate Impacts Consortium (PCIC) 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 downscaled climate projections under the RCP 8.5 emission scenario were used for Project area.

7.2 LIMITATIONS OF CLIMATE CHANGE RESILIENCE ASSESSMENT

This CCRA was completed using the best information available to the assessment team at the time of study. The assessment represents the risks associated with the current climate and future climate projections for the planned assets and infrastructure components of the Project.

The climate data and trends (current and future projections) used in this assessment were obtained through various sources. Cross-verification between climate information sources was conducted where possible to identify potential discrepancies between the data sources used.

The availability of weather data to define the intensity thresholds of the selected climate hazards, as well as their occurrence in current climate are based on data from the ECCC weather stations. It is recognized that extreme weather events are often very localized, so it is possible that some climate events are not recorded by the weather stations. This uncertainty is considered by the climate change resilience assessment during the analysis, including the knowledge of the team members in the analysis of asset vulnerabilities and infrastructure elements.

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9.0 CLOSURE

This TDR was prepared for the sole benefit of the Proponents for the Project to complete the Strategic Assessment of Climate Change.

Respectfully submitted,

Stantec Consulting Ltd. and Ksi Lisims LNG

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