Technical Data Report Greenhouse Gas Emissions, Revision 1

Cedar LNG Project

April 2022

Prepared for:

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Revision Note

This version of the Technical Data Report – Greenhouse Gas Emissions Cedar LNG Project has been issued to update emissions reported in the Executive Summary and Section 5.2, including Table 5.2, of the November 2021 report. The revised greenhouse gas emissions reflect the preliminary front end engineering design information for the Cedar LNG Project. These changes do not affect the content or conclusions of the Environmental Assessment Certificate Application or the Strategic Assessment of Climate Change.

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Ward Prystay, M.Sc., R.P.Bio.

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Executive Summary

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

The Project is subject to environmental assessment requirements under the British Columbia *Environmental Assessment Act* and the federal *Impact Assessment Act*. This technical data report (TDR) presents the greenhouse gas (GHG) emission inventory for the Project including the study area and methods used to estimate the emissions.

Sources of GHG emissions arising from activities during construction and operation include:

Construction:

- Off-road construction equipment
- On-road construction equipment
- Blasting
- Land clearing, biomass burning and decay

Operation:

- Stationary combustion equipment (regeneration gas heater, auxiliary boiler, pumps and generators)
- Thermal oxidizer
- Flares
- Marine operation (LNG carriers and tugboats)
- Acquired energy emissions (electricity)

The GHG emissions arising from activities during decommissioning are only assessed qualitatively. Emissions are expected to be small and comparable to construction emissions (minus the land clearing emissions).

The total direct GHG emissions released during construction activities are estimated to be 9,922 tonnes of carbon dioxide equivalent (t CO_2e) when excluding land clearing emissions and 36,652 t CO_2e when including land clearing emissions.

The direct GHG emissions released during operation of the Project were estimated to be 215,700 t CO_2e per year (excluding LNG carrier emissions). The emissions from acquired electricity were estimated at 27,749 t CO_2e per year. Total annual direct and indirect emissions (excluding LNG carrier emissions) were estimated to be 240,449 t CO_2e per year. Using the total direct and indirect emissions of 240,449 t CO_2e per year and the three million tonnes of LNG per year (MTPA) production output, the emission intensity of the project operation is anticipated to be 0.08 t of CO_2e per tonne of LNG.

Abbreviations

ANFO	ammonium nitrate/fuel oil
the Application	Application for an Environmental Assessment Certificate
BSFC	brake specific fuel consumption
Cedar	Cedar LNG Partners LP
CH_4	methane
CO_2	carbon dioxide
CO_2e	carbon dioxide equivalent
ECCC	Environment and Climate Change Canada
FLNG	Floating liquefied natural gas
FLNRORD	Ministry of Forests, Lands, Natural Resource Operations and Rural Development
g	gram
GHG	greenhouse gas
GJ	gigajoule
GWh	gigawatt hour
GWP	global warming potential
ha	hectare
HFC	hydrofluorocarbon
HHV	higher heating value
hp	horsepower
IPCC	Intergovernmental Panel on Climate Change
km	kilometre
kW	kilowatt

L	litre
lb	pound
LLAF	low load adjustment factor
LNG	liquefied natural gas
m^3	cubic metre
MTPA	million tonnes per annum
N_2O	nitrous oxide
NF_3	nitrogen trifluoride
NIR	National Inventory Report (from ECCC)
PFC	perfluorocarbon
SF_6	sulphur hexafluoride
sm^3	standard cubic metre (at 15°C and 101.325 kPa)
TDR	Technical Data Report
WCI	Western Climate Initiative
y	year

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 on the atmosphere.
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°C where the methane and other components condense from gas to liquid form. In its liquid state, natural gas takes up 1/600 of the space that the gaseous phase occupies.
LNG carrier	A marine cargo ship with specialized cryogenic tanks that are designed for transporting liquefied natural gas.
Natural gas	A naturally occurring hydrocarbon gas mixture consisting primarily of methane (typically >98%) plus varying amounts of ethane, propane, butanes, pentanes, higher molecular weight hydrocarbons, hydrogen sulfide, carbon dioxide, water vapor, and sometimes helium and nitrogen.

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1.0 INTRODUCTION

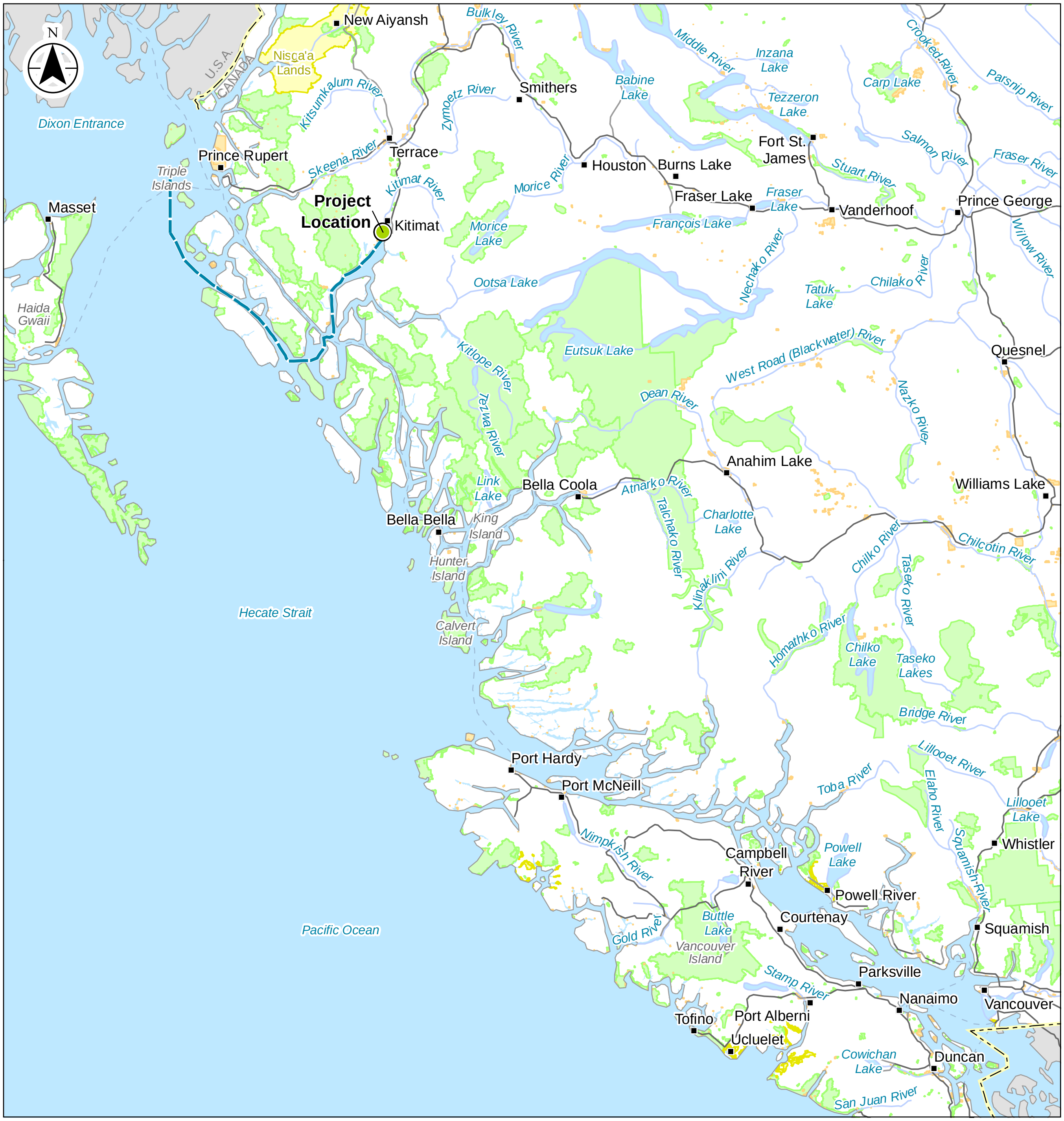
Cedar LNG Partners LP (Cedar), a Haisla Nation-led partnership with Pembina Pipeline Corporation, is proposing to construct and operate the Cedar LNG Project (the Project), a liquefied natural gas (LNG) export facility within the District of Kitimat, British Columbia. The Project will be located on Haisla Nation-owned land within the Nation's traditional territory, approximately 3 kilometres (km) west across Kitimat Arm from Kitamaat Village and approximately 10 km southwest of Kitimat's town centre (Figure 1).

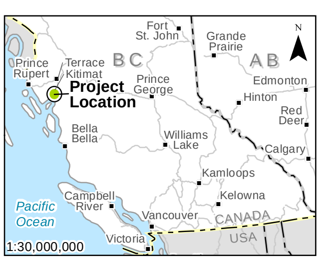
The Project is subject to environmental assessment requirements under the British Columbia *Environmental Assessment Act* and the federal *Impact Assessment Act*. This technical data report (TDR) provides the methods and the estimates used in the quantification of greenhouse gas (GHG) emissions associated with the Project to support Section 8.0 of the Environmental Assessment Certificate Application (the Application) and permitting requirzements.

Information presented in this TDR has been obtained from Cedar, existing literature, published technical data sources, engineering calculations, or from previous similar project experience.

The following information is presented within this report:

- Location of the study area (Section 2.0)
- Substances of interest, i.e., the specific GHGs assessed for this Project (Section 3.0)
- Description of the methods for estimating the quantities of GHG emissions (Section 4.0)
- Summary of estimated GHG emissions by project phase (Section 5.0)





Highway
Road
Ferry Route
Watercourse
Waterbody
Reserve Land
Treaty Lands
Park or Protected Area

Project Location
Marine Shipping Route
(Approximate Location)

0 50 100 150
km
1:4,000,000 (at original document size of 8.5x11)

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

Stantec CEDAR LNG

Project Location:
Kitimat,
British Columbia

Project Number 123221953
Prepared by LTRUDELL on 20211126
Discipline Review by WPRYSTAY on 20211126
GIS Review by SFORTAIS on 20211126

Client/Project/Report
Cedar LNG Partners LP
Cedar LNG Project
Technical Data Report Greenhouse Gas Emissions

Figure No.
1

Title
Cedar LNG Project Location

2.0 STUDY AREA

The Project is located approximately 10 km southwest of Kitimat's town centre. The nearest residential area to the Project is Kitamaat Village, located approximately 3 km directly east across Kitimat Arm.

No local or regional spatial boundaries are used for the assessment of GHGs, as the environmental effect associated with GHG emissions is a global phenomenon. This is based on GHGs mixing well in the atmosphere and dispersing from their emission sources (IPCC 2013).

However, as a reference point, this assessment will consider the estimated tonnage of released GHGs during project construction and operation relative to provincial and federal GHG inventories. Administrative provincial and federal boundaries are hence selected to create a context for the Project's GHG emissions. It is noted, though, that the emissions disperse beyond these administrative boundaries.

3.0 SUBSTANCES OF INTEREST

A GHG can be any atmospheric gas that absorbs and re-emits infrared radiation, thereby acting as a thermal blanket for the planet that warms the lower levels of the atmosphere. Greenhouse gases can be released from both natural and anthropogenic (human activity) sources (IPCC 2013).

Greenhouse gases are estimated provincially and federally in Canada and are reported annually in the National Inventory Report (NIR) published by Environment and Climate Change Canada (ECCC). The national GHG inventory includes the following gases: carbon dioxide (CO_2), methane (CH_4), nitrous oxide (N_2O), perfluorocarbons (PFCs), hydrofluorocarbons (HFCs), sulphur hexafluoride (SF_6) and nitrogen trifluoride (NF_3) (ECCC 2021). This assessment is considering the same set of GHGs as the NIR.

For this assessment, the GHGs that may be released during project activities include CO_2, CH_4 and N_2O. The GHGs that are not expected to be emitted by the Project are PFC, HFC, and NF_3 as these gases are assumed not present in substantial amounts in any project activities. SF_6 will be used as an insulating medium for the high voltage gas insulated switchgear in the electrical system; however, these units are sealed and designed to not allow gases to escape. The units will also be equipped with a means to monitor for leaks. These gases are, therefore, excluded from further consideration in this assessment.

Emissions of each of the included GHGs are multiplied by their 100-year global warming potential (GWP) as determined by the Intergovernmental Panel on Climate Change (IPCC) and are reported as carbon dioxide equivalent (CO_2e). The GWP of these GHGs align with the ones applied in the 2019 NIR (ECCC 2021):

- CO_2 = 1
- CH_4 = 25
- N_2O = 298

Total mass of CO_2e for the Project is calculated as:

$$CO_2e = (mass\ CO_2 * 1) + (mass\ CH_4 * 25) + (mass\ N_20 * 298)$$

4.0 METHODOLOGY

The methods used to estimate the GHG emissions from the Project are based on accounting and reporting principles of The Greenhouse Gas Protocol developed by the World Resource Institute and the World Business Council for Sustainable Development (2015). The GHG Protocol is an internationally accepted accounting and reporting standard for quantifying and reporting GHG emissions. The guiding principles of the Protocol are relevance, completeness, consistency, transparency, and accuracy.

The sections below describe the specific quantification methods used to estimate GHG emissions from construction and operation phase emission sources.

4.1 CONSTRUCTION PHASE

The floating LNG (FLNG) facility itself is assembled overseas and any emissions associated with its construction are not included in the scope of this assessment. Activities included in the scope of this assessment are the construction of the transmission line and the marine terminal including the small craft wharf and the strut mooring for the FLNG facility. Construction is estimated to begin in 2023 and last approximately up to four years (subject to regulatory approval timelines).

Direct and indirect emissions associated with the construction activities listed above have been divided in the following five categories:

Direct GHG emissions:

- Emissions from fuel combustion by off-road vehicles and equipment
- Emissions from fuel combustion by on-road vehicles and equipment
- Emissions associated with land clearing activities necessary to build the transmission line as well as the marine terminal
- Emissions associated with blasting activities necessary to prepare the site

The construction activity assumptions and details, such as type and number of equipment, load factors, total operating hours of construction equipment and fuel consumption, are based on input from Cedar or published literature. The equipment list and operation schedules are based on the best information available at the time of the assessment. Construction emission estimates consider the full build-out scenario. The methods and emission calculations for each category are explained in the following sections.

4.1.1 Off-Road Construction Equipment

Off-road equipment and vehicles used for the construction of the transmission line and marine terminal include heavy-duty equipment such as bulldozers, excavators, backhoes, graders, compactors, helicopters, as well as generators and light towers. The majority of the construction equipment is assumed to be diesel-powered or marine diesel-powered. There is some equipment powered by gasoline and aviation gas. As marine diesel-powered equipment GHG emission calculation approach is different from non-marine diesel-powered equipment, GHG emission estimations from non-marine diesel-powered and marine diesel-powered equipment are described separately.

4.1.1.1 Non-Marine Diesel-Powered Construction Equipment

Table 4.1 lists off-road construction equipment powered by diesel, gasoline, and aviation gas. Equipment operation information and fuel consumptions are also shown in Table 4.1. For diesel-fueled equipment, brake specific fuel consumptions (BSFC) were obtained from *Exhaust and Crankcase Emission Factors for Nonroad Compression-Ignition Engines in MOVES2014b* (U.S. EPA 2018). For gasoline-fueled equipment, fuel consumption was estimated using the U.S. EPA AP 42 BSFC value (U.S. EPA 1996) and the off-road motor gasoline higher heating value (Western Climate Initiative (WCI) 2011). For helicopters, the volume of aviation gas consumed over the construction period was estimated from manufacturer information.

Emission factors applicable to the off-road construction equipment are listed in Table 4.2.

Emissions for construction period are calculated as:

$$\begin{aligned} &Emission\ for\ construction\ period\ (tonnes) \\ &\qquad = Operating\ time\ \ (hr) * Fuel\ Consumption\ \left(\frac{L}{hr}\right) * Utilization\ \left(\frac{\%}{100}\right) \\ &\qquad * \ Emission\ Factor\ \left(\frac{g}{L}\right) * Unit\ Conversion\ (\frac{1\ tonne}{10^6 g}) \end{aligned}$$

The fuel consumption for off-road diesel equipment was estimated based on equipment-specific horsepower (hp) rating, load factor, and brake-specific fuel consumption. Load factors were sourced from the U.S. EPA NONROAD engine emissions model (U.S. EPA 2010). The equipment-specific fuel consumption rate is estimated as:

$$\begin{aligned} &Fuel\ Consumption\ \left(\frac{L}{hr}\right) \\ &\qquad = Engine\ Power\ (hp) * Load\ Factor\frac{(\%)}{100} * Brake\ Specific\ Fuel\ Consumption\ \left(\frac{lb}{hp * hr}\right) \\ &\qquad * Conversion\ \left(0.454\frac{kg}{lb}\right) \div Diesel\ Density\ (0.86\frac{kg}{L}) \end{aligned}$$

Table 4.1 Non-Marine Diesel-Powered Off-Road Equipment List and Fuel Consumption Rates

Description [a]	Fuel Type [a]	Number of Units [a]	Engine Power [a] (hp)	Load Factor (fraction of power) [b]	Operating Hours / unit/ day [a] (hr)	Duration [a] (d)	Utilization [a] (%)	BSFC [c] (lb/hp-hr)	Fuel Consumption [d] (L/hr)
Marine Terminal									
Bulldozer	Diesel	3	303	0.59	10	62	75%	0.367	104
Excavator	Diesel	5	345	0.59	10	184	75%	0.367	197
Concrete truck	Diesel	3	380	0.59	10	89	75%	0.367	130
Concrete pump truck (alliance 47 m boom on a Mack truck)	Diesel	1	505	0.59	10	93	75%	0.367	57.7
Scraper	Diesel	2	408	0.59	10	67	75%	0.367	93.1
Compactor	Diesel	5	157	0.59	10	120	75%	0.367	89.6
Crane (rough terrain 110 t)	Diesel	3	270	0.43	10	222	75%	0.367	67.3
Oil tanker truck (fuel truck)	Diesel	1	385	0.59	10	27	75%	0.367	44.0
Water truck	Diesel	2	385	0.59	10	167	75%	0.367	87.9
Front end loader	Diesel	2	276	0.59	10	333	75%	0.367	63.1
Grader	Diesel	1	238	0.59	10	133	75%	0.367	27.2
Articulated truck (dump truck)	Diesel	5	496	0.59	10	160	75%	0.367	283
Track drill	Diesel	2	540	0.43	10	67	75%	0.367	90.0
Paving machine	Diesel	1	142	0.59	10	15	75%	0.367	16.2
Welding trailer/rig	Diesel	2	385	0.43	10	60	75%	0.367	64.1
Temporary gensets (63 kW each)	Diesel	5	84	0.43	10	411	75%	0.408	39.1

Table 4.1 Non-Marine Diesel-Powered Off-Road Equipment List and Fuel Consumption Rates

Description [a]	Fuel Type [a]	Number of Units [a]	Engine Power [a] (hp)	Load Factor (fraction of power) [b]	Operating Hours / unit/ day [a] (hr)	Duration [a] (d)	Utilization [a] (%)	BSFC [c] (lb/hp-hr)	Fuel Consumption [d] (L/hr)
Tower light plant	Diesel	4	11	0.43	10	180	75%	0.408	3.97
Piling rigs (shore-based diesel hammer)	Diesel	2	N/A	0.43	10	365	75%	N/A	45.0 [e]
Piling rigs (shore-based vibratory hammer)	Diesel	2	335	0.43	10	365	75%	0.367	55.8
Piling rig (containing the hydraulic power packs)	Diesel	4	523	0.43	10	365	25%	0.367	174
Floating crane barge (pontoon with liebherr crawler crane)	Diesel	1	898	0.43	10	60	75%	0.367	74.8
Transmission line Construction									
Crawler tractor	Diesel	1	216	0.59	10	60	33%	0.367	24.7
Backhoe	Diesel	1	270	0.21	10	60	17%	0.367	11.0
Compactor	Diesel	1	157	0.59	10	60	25%	0.367	17.9
Tracked tank drill	Diesel	1	42	0.43	10	60	2%	0.408	3.85
Excavator	Diesel	1	143	0.59	10	60	42%	0.367	16.4
Chainsaw	Gasoline	1	5	0.59	10	90	55%	N/A	1.13 [f]
Feller buncher	Diesel	1	330	0.70	10	90	32%	0.367	44.7
Skidder	Diesel	1	193	0.59	10	90	64%	0.367	22.1
Excavator w/ rake	Diesel	1	311	0.59	10	90	96%	0.367	35.5
Dozer	Diesel	1	303	0.59	10	90	32%	0.367	34.6
Logging truck	Diesel	1	630	0.59	10	90	9%	0.367	72.0
Mini-hoe	Diesel	1	21	0.21	10	20	100%	0.408	0.97

Table 4.1 Non-Marine Diesel-Powered Off-Road Equipment List and Fuel Consumption Rates

Description [a]	Fuel Type [a]	Number of Units [a]	Engine Power [a] (hp)	Load Factor (fraction of power) [b]	Operating Hours / unit/ day [a] (hr)	Duration [a] (d)	Utilization [a] (%)	BSFC [c] (lb/hp-hr)	Fuel Consumption [d] (L/hr)
Excavator	Diesel	1	345	0.59	10	30	27%	0.367	39.4
Concrete truck	Diesel	1	380	0.59	10	30	40%	0.367	43.3
Crawler tractor	Diesel	1	216	0.59	10	30	27%	0.367	24.7
Low-bed / equipment hauler	Diesel	1	630	0.59	10	30	5%	0.367	72.0
Forklift	Diesel	1	74	0.59	10	30	13%	0.408	9.36
Helicopter (medium)	Aviation gas	1	848	N/A	84 [g]	N/A	100%	N/A	180 [a]
Rock drill	Diesel	1	540	0.43	10	16	100%	0.367	45.0
100-ton crane	Diesel	1	270	0.43	10	15	96%	0.367	22.4
Low-bed / equipment hauler	Diesel	1	630	0.59	10	15	11%	0.367	72.0
Helicopter (heavy lift)	Aviation gas	1	1800	N/A	13 [g]	N/A	100%	N/A	310 [a]
Road grader	Diesel	1	239	0.59	10	15	27%	0.367	27.3
Crawler tractor	Diesel	1	216	0.59	10	15	80%	0.367	24.7
Tensioner	Diesel	1	141	0.59	10	6	100%	0.367	16.1
50-ton crane	Diesel	1	190	0.43	10	10	19%	0.367	15.9
Low-bed / equipment hauler	Diesel	1	630	0.59	10	10	8%	0.367	72.0
Puller on trailer	Diesel	1	34	0.59	10	10	60%	0.408	4.32
Rope machine	Diesel	1	483	0.59	10	10	58%	0.367	55.1
Forklift	Diesel	1	74	0.59	10	10	8%	0.408	9.36
Skidder	Diesel	1	193	0.59	10	10	16%	0.367	22.1

Table 4.1 Non-Marine Diesel-Powered Off-Road Equipment List and Fuel Consumption Rates

Description [a]	Fuel Type [a]	Number of Units [a]	Engine Power [a] (hp)	Load Factor (fraction of power) [b]	Operating Hours / unit/ day [a] (hr)	Duration [a] (d)	Utilization [a] (%)	BSFC [c] (lb/hp-hr)	Fuel Consumption [d] (L/hr)
Backhoe	Diesel	1	270	0.21	10	10	32%	0.367	11.0
Crawler tractor	Diesel	1	216	0.59	10	10	32%	0.367	24.7

NOTES:

[a] From Cedar or scaled from the Northwest Transmission line Project (Rescan 2009)

[b] Based on U.S. EPA (2010)

[c] Based on U.S. EPA (2018)

[d] Estimated based on BSFC value and fuel density. Diesel fuel density 0.86 kg/L, gasoline density 0.78 kg/L, and aviation gas density 0.8 kg/L

[e] Based on Woodfibre LNG Project (Stantec 2021)

[f] Estimated using average brake-specific fuel consumption 7,000 Btu/hp-hr (U.S. EPA 1996, Table 3.3-1) and motor gasoline off-road higher heating value of 35 GJ/kL (WCI 2011, Table 20-1)

[g] Total operation hours during construction period, provided by Cedar

N/A – not available

Table 4.2 Emission Factors for Non-Marine Diesel Off-Road Engines

Emission Source	Emission Factor (g/L Fuel)		
	CO_2	CH_4	N_2O
Diesel engine	2,663	0.133	0.40
Gasoline engine	2,289	2.7	0.05
Helicopter	2,342	2.2	0.23
SOURCE: WCI 2011, Table 20-2.			

4.1.1.2 Marine Diesel-Powered Construction Equipment

Table 4.3 lists marine diesel-powered equipment operation information and GHG emissions factors. Equipment load factors and power-based GHG emission factors (in units of g/kWh) were obtained from *Ports Emissions Inventory Guidance: Methodologies for Estimating Port-Related and Goods Movement Mobile Source Emissions* (U.S. EPA 2020).

Emissions for the construction period are calculated as:

$$\begin{aligned} & Emissions\ for\ Construction\ Period\ (tonnes) \\ & \quad = Operating\ time\ \ (hr) * Engine\ Power\ (hp) * Load\ Factor \frac{(\%)}{100} \\ & \quad * Unit\ Conversion\ \left(0.746 \frac{kW}{hp}\right) * Utilization\ \left(\frac{\%}{100}\right) * \ Emission\ Factor\ \left(\frac{g}{kWhr}\right) \\ & \quad * Unit\ Conversion\ (\frac{1\ tonne}{10^6 g}) \end{aligned}$$

Table 4.3 Marine Diesel-Powered Off-Road Equipment List and Emission Factors

Description [a]	Engine Manufacturer [a]	Engine Model [a]	Fuel Type [a]	Number of Vessels [a]	Engine Power [a] (hp)	Load Factor [b]	Operating Hours per Day [a] (hr/d)	Duration during Construction [a] (d)	Utilization [a] (%)	Emission Factors [b]		
										CO_2 (g/kWh)	CH_4 (g/kWh)	N_2O (g/kWh)
SPUD barge (self-propelled)	Combifloat	C-9.5	Marine diesel	1	456	0.43	10	60	75%	679.47	0.002	0.033
Tugboat (tow vessel, 75 t)	CAT engine	3516E engine	Marine diesel	8	4000	0.50	10	60	75%	679.47	0.0003	0.033
Work boat	John Deere	6068AFM85	Marine diesel	1	250	0.45	10	180	75%	679.47	0.002	0.033

NOTES:
[a] From Cedar
[b] From U.S. EPA 2020

4.1.2 On-Road Construction Vehicles

On-road construction vehicles used for the construction of the Project include equipment such as pick-up trucks and crew buses. On-road vehicle operation information is listed in Table 4.4. The on-road construction vehicles are assumed diesel-powered. The fuel consumption rates of on-road vehicles (in units of mile/gallon) were based on typical fuel economy for trucks based on vehicle weight as published by the United States Department of Energy (Oak Ridge National Laboratory 2017). Fuel consumption rates are also shown in Table 4.4.

$$Fuel\ Consumption\ \left(\frac{L}{hr}\right) = Road\ Length\ per\ Trip\ \left(\frac{km}{trip}\right) * Vehicle\ Trips\ \left(\frac{trip\ number}{hr}\right) \div \left\{\left(Fuel\ Consumption\ \left(\frac{mile}{gallon}\right) * Unit\ Conversion\ \left(\frac{gallon}{3.785\ L}\right) * Unit\ Conversion\ \left(\frac{1.609\ km}{mile}\right)\right\}$$

Diesel fuel combustion GHG emission factors are shown in Table 4.2 above.

Emissions for the construction period are calculated as:

$$Emissions\ for\ Construction\ Period\ (tonnes) = Operating\ time\ (hr) * Fuel\ Consumption\ \left(\frac{L}{hr}\right) * Utilization\ \left(\frac{\%}{100}\right) * Emission\ Factor\ \left(\frac{g}{L}\right) * Unit\ Conversion\ \left(\frac{1\ tonne}{10^6 g}\right)$$

Table 4.4 On-Road Equipment List and Fuel Consumptions

Haul Road [a]	Engine Power [a] (hp)	Road Length (Return Trip) [a] (km)	Fuel Type [a]	Number of Vehicles [a]	Operating Hours per Day [a] (hr/d)	Operating Days [a] (d)	GVWR [a] (tonne)	Number of Round Trips (Return Trips) [a]			Utilization [a] (%)	Fuel Consumption		
								Trips/ Vehicle/d	Vehicle-Trips/d	Vehicle-Trips/h		Mile/ Gallon [b]	km/L	L/h
Crew bus (Blue Bird conventional BBCV2311)	260.2	16	Diesel	4	10	365	15	10	40	4	50%	20.4	8.67	7.38
Pick-up trucks (half-ton)	399.6	16	Diesel	10	10	173	3	4	40	4	75%	20.4	8.67	7.38

NOTES:
[a] Provided or confirmed by Cedar. One way road length is 8.0 km
[b] Based on Oak Ridge National Laboratory (2017)
[c] Calculated based on road length and number of round trips per hour

4.1.3 Blasting

There will be blasthole drilling and blasting activities during construction at the marine terminal footprint. GHG emissions will be released due to the combustion of the ammonium nitrate/fuel oil (ANFO) explosive. Table 4.5 lists blasthole drilling and blasting information and relevant GHG emissions factors. It is anticipated that there will be roughly 2,200 blasting holes over the construction period. It is assumed that one hole will use approximately 200 kg ANFO (Stantec 2017). The GHG emissions factors applied for the ANFO explosive are from *Energy and GHG Emissions Management Guidance Document* (The Mining Association of Canada 2009).

Emissions for the construction period are calculated as:

$$
\begin{aligned}
&Emissions\ for\ Construction\ Period\ (tonnes) \\
&\qquad = Blast\ Hole\ Number\ (hole) * ANFO\ Usage\ \left(\frac{kg\ ANFO}{hole}\right) * \ Emission\ Factor\ \left(\frac{kg}{kg\ ANFO}\right) \\
&\qquad * \ Unit\ Conversion\ \left(\frac{1\ tonne}{10^3 kg}\right)
\end{aligned}
$$

Table 4.5 Blasting Information and Emission Factors

Construction Phase	Description	Blasted Volume [a] (m^3)	Assumed Depth of Blasting Area [a] (m)	Assumed Area Covered per Blast Hole [c] (m^2)	Number of Blast Holes [b]	ANFO Usage [c] (kg/hole)	Duration [a] (d)	GHG Emissions Factors [d] CO_2	CH_4	N_2O
								kg/kg of ANFO Explosive		
Preparation and installation	Blasting	54,883	1.00	25	2,193	200	50	0.189	N/A	N/A

NOTES:
[a] Provided or confirmed by Cedar
[b] Calculated based on marine terminal area size and one blast hole area size
[c] Based on Lynn Lake Gold Project (Stantec 2017)
[d] From The Mining Association of Canada (2009)
N/A – not available

4.1.4 Land Clearing Biomass Burning and Decay

Building the transmission line and the marine terminal will require clearing of the existing vegetation. It is assumed that all vegetation will be burned after being cleared. Greenhouse gas emissions will be released from the burning of the biomass and the subsequent decay of the remaining biomass after the clearing. The total area to be cleared for the Project is estimated to be 46.3 hectares (ha).

To quantify the land clearing emissions for approximately 46.3 ha, this assessment uses emission factors developed by C. Dymond in conjunction with the British Columbia Ministry of Forests, Lands, Natural Resource Operations and Rural Development (FLNRORD) (Dymond 2014). These emission factors are ecoregion specific and are expressed in tonnes of CO_2e emitted per hectare land cleared (see Table 4.6).

It has been conservatively assumed that the entire 46.3 ha is vegetated, and that the area does not contain any merchantable timber. Therefore, the applicable emission factor is the one for the uproot and burn activity where it is assumed that all organic carbon is emitted to the atmosphere (see Table 4.6).

The FLNRORD GHG emission factors do not account for potential regrowth of a stand; the emission factors are for deforestation activities only, which is defined as the permanent conversion of land from forests to other land use (IPCC 2003). In practical terms, the emission factors are used for areas converted from forest to non-forest for 20 years or more. However, the FLNRORD emission factors do account for decay emissions from leftover litter, dead biomass, woody debris, and soil carbon. The decay emission factors (see Table 4.6) account for decay occurring over a period of 19 years following the year of the disturbance. This combined timeframe of 20 years follows IPCC guidance (2003), which states that impacts on soil organic matter will last for 20 years before a new equilibrium is reached (Tier 1). As per Tier 1 approach, Stantec accounted for decay emissions occurring over 19 years in the construction phase of the Project. This practice draws a distinct accounting separation between construction-related emissions from those related to operation activities.

Table 4.6 Land Clearing Emission Factors

Ecoregion	Emission Factor (Average tonnes of CO_2e/ha land cleared)	Practice
Skeena	349	Uproot and burn (all harvested carbon assumed emitted)
	228	Decay for 19 years following the year of disturbance
SOURCE: Dymond 2014		

Land clearing emissions are calculated as:

$$Emissions\ (t\ CO_2e\ ) = Area\ cleared\ (ha) * Emission\ Factor\ Uproot\ and\ Burn\ \left(\frac{tCO_2e}{ha}\right) + \ Area\ cleared\ (ha) * Emission\ Factor\ Decay\ \left(\frac{tCO_2e}{ha}\right)$$

4.2 OPERATION PHASE

The operation phase is anticipated to begin in 2027 and is expected to continue for 40 years. Project design currently includes emission sources for the operation phase include direct and indirect emissions.

Direct GHG emission sources are:

- One regeneration gas heater
- One auxiliary boiler
- Two firewater pumps and four generators
- One acid gas thermal oxidizer
- Flares including:
  - Warm flare
  - Cold flare
  - Low-pressure flare

Marine operation including:

- LNG carriers
- Tugboats

Indirect GHG emissions:

- Electricity consumption (acquired energy)

The Project is not expected to release any substantial amount of natural gas via voluntary venting or involuntarily via fugitive emissions. For example, venting emissions from the electric compressors are connected to the flare. Any pneumatic instruments or equipment will use instrument air as a pneumatic power source. Industry standard bolt torquing practices will be used to limit fugitive emissions from flange leaks. Any equipment, vessel, or pipeline gas blowdowns will be captured and sent to flare.

The following subsections summarize the methods and assumptions used to estimate GHG emissions from normal operation activities for each source.

The following table presents the gas compositions and the associated higher heating values (HHV) used in this assessment as provided by Cedar (see Table 4.7).

Table 4.7 Gas Analyses

Compound	Normalized Mole Fraction [a]		
	Design Fuel Gas	Thermal Oxidizer Acid Gas	Thermal Oxidizer Mixed Gas
H_2O (water)	0	0.0381	0.0269
H_2 (hydrogen)	0	0	0
He (helium)	0	0	0
N_2 (nitrogen)	0.0770	0	0.0226
CO_2 (carbon dioxide)	0	0.956	0.6759
H_2S (hydrogen sulphide)	0.000003	0.0000067	0.0000056
C1 (methane)	0.7980	0.0041	0.2367
C2 (ethane)	0.0001	0.001	0.0007
C3 (propane)	0	0.0008	0.0006
I-C4 (isobutane)	0	0	0
n-C4 (normal butane)	0	0	0
I-C5 (isopentane)	0.0217	0	0.0064
n-C5 (normal pentane)	0.0389	0	0.0114
C6 (hexane)	0.0353	0	0.0103
C7+ (heptane)	0.0290	0	0.0085
Total	1.00	1.00	1.00
HHV [b] (MJ/m^3)	51.38	0.30	15.26

NOTES:
[a] Provided by Cedar
[b] HHV = Higher heating value. Project-specific HHVs are used to adjust the Western Climate Initiative (WCI) emission factors.

4.2.1 Regeneration Gas Heater and Auxiliary Boiler

The proposed regeneration gas heater and auxiliary boiler are assumed to run on design fuel gas with a HHV of 51.38 MJ/m^3 (see Table 4.7). Table 4.8 shows the fuel consumption and operating hours per year as provided by Cedar. Quantities of GHGs released from the regeneration gas heater and the auxiliary boiler are estimated based on equipment-specific fuel consumption rates, operating hours, and the gas composition, following WCI methods (2012) (WCI.23 Equation 20-1 for CO_2 and WCI.24 Equation 20-12 for CH_4 and N_2O). Emissions are calculated as per the equations shown below. For the CO_2 emission calculation, a molar volume conversion factor of 23.6449 m^3/kg-mole at standard condition (15°C and 101.325 kPa) is applied. The applied emission factors for CH_4 and N_2O are shown in Table 4.9.

Table 4.8 Regeneration Gas Heater and Auxiliary Boiler Operation Information

Variable	Regeneration Gas Heater	Auxiliary Boiler
Operating hours [a]	5,652 hours per year (operates 65% of the year)	350 hours per year (operates seasonally)
Fuel type [a]	Design fuel gas	Design fuel gas
Fuel consumption [a]	701 sm^3/hr [b]	4,893 sm^3/hr
NOTES: [a] Provided by Cedar [b] sm^3/hr = standard cubic metre per hour		

Table 4.9 Regeneration Gas Heater and Auxiliary Boiler Natural Gas Emission Factors

Equipment	Emission Factor	
	CH_4 (g/GJ fuel)	N_2O (g/GJ fuel)
Industrial fuel gas burning stationary combustion equipment	0.966	0.861
SOURCE: WCI 2012		

$$CO_2\ Emission\left(\frac{tonnes}{y}\right) = \sum Design\ Fuel\ Gas\ Rate\left(\frac{m^3}{hr}\right) * Operating\ Time\left(\frac{hr}{y}\right) * (Mole\ Fraction\ of\ Hydrocarbon\ Constituents) * (Number\ of\ Carbon\ Atoms\ in\ the\ Hydrocarbon\ Constituent) * Molecular\ Weight\ of\ Carbon\left(\frac{12\ kg\ C}{kg\text{-}mole}\right) \div Molar\ Volume\ Conversion\ Factor\left(\frac{23.6449\ m^3}{kg\text{-}mole}\right) * 3.664\ \frac{kg\ CO_2}{kg\ C} * Unit\ Conversion\left(\frac{1\ tonne}{10^3\ kg}\right)$$

$$CH_4\ and\ N_2O\ Emission\left(\frac{tonne}{y}\right) = \sum Design\ Fuel\ Gas\ Rate\left(\frac{m^3}{hr}\right) * Operating\ Time\left(\frac{hr}{y}\right) * Fuel\text{-}specific\ HHV\left(\frac{GJ}{m^3}\right) * Emission\ Factor\left(\frac{g}{GJ}\right) * Unit\ Conversion\left(\frac{1\ tonne}{10^6\ g}\right)$$

4.2.2 Firewater Pumps and Generators

Project design currently includes two firewater pumps, three electrical generators, and one inert gas generator. The firewater pumps and electrical generators are for backup emergency purposes. The inert gas generator will be used for tank maintenance (i.e., once every five years). All these units are assumed to run on marine gas oil (No. 2 fuel oil or diesel). Table 4.10 shows fuel consumption and equipment operating hours per year as provided by Cedar.

Quantities of GHGs released from project equipment are estimated based on equipment-specific fuel consumption rates (L/hr) and diesel combustion emission factors from WCI (2012). Table 4.11 shows diesel emission factors for CO_2, CH_4, and N_2O (WCI 2012). Emissions are calculated as per the equation shown below, following WCI.23 Equation 20-1 (for CO_2e) and WCI.24 Equation 20-10 (for CH_4 and N_2O) (WCI 2012).

Table 4.10 Firewater Pumps and Emergency Generators Operation Information

Variable and Units		Firewater Pump A	Firewater Pump B	Electrical Generator A	Electrical Generator B	Electrical Generator C	Inert Gas Generator
Operating frequency [a]	Weekly/ monthly	Weekly	Weekly	Monthly	Monthly	Weekly	Monthly
Operating hours [a]	hr/y	26	26	12	12	26	38.4
Fuel consumption [a]	kg/hr	186	186	602	602	602	257
NOTE: [a] Provided by Cedar. Based on anticipated testing schedule.							

Table 4.11 Firewater Pumps and Emergency Generators Diesel Emission Factors

Equipment	Emission Factors		
	CO_2 (g/L fuel)	CH_4 (g/L fuel)	N_2O (g/L fuel)
Diesel burning equipment	2,663	0.133	0.40
SOURCE: WCI 2012	Table 20-2	Table 20-2	Table 20-2

$$Emissions\left(\frac{tonnes}{y}\right) = Fuel\ Rate\left(\frac{kg}{hr}\right) \div Fuel\ Density\left(\frac{0.86\ kg}{L}\right) * Emission\ Factor\left(\frac{g}{L}\right) * Unit\ Conversion\left(\frac{1\ tonne}{10^6 g}\right) * Operating\ Time\left(\frac{hr}{y}\right)$$

4.2.3 Thermal Oxidizer

Current design includes a thermal oxidizer that is assumed to run on a mixture of acid gas and design fuel gas. The flow rates of acid gas and design fuel gas are 7,398 standard cubic metre (sm^3) per hour and 3,065 sm^3 per hour, respectively. The mixed gas flow rate is 10,463 sm^3 per hour. The thermal oxidizer is assumed to operate 365 days a year. The operating information including operating hours and fuel consumptions are listed in Table 4.12 as provided by Cedar.

The quantities of GHGs released from the thermal oxidizer were estimated following the WCI.363 equations 360-27 through 360-31 (WCI 2012). The combustion efficiency for the conversion of CH_4 to CO_2 was set to 99.9% (CAPP 2014). Densities of CO_2 and CH_4 are 1,861 g/sm^3 and 678 g/sm^3 and the N_2O emission factor is 9.52×10^{-5} kg/GJ as per WCI guidance (WCI 2011, 2013). The emissions are calculated based on the mixed gas flow. Emissions are calculated as per the equations shown below.

Table 4.12 Thermal Oxidizer Operation Information

Variable	Thermal Oxidizer
Operating hours [a]	8,760 hours per year
Fuel type [a]	Acid Gas + Design Fuel Gas
Fuel consumption [a, b]	10,463 sm^3/hr
NOTES: [a] Provided by Cedar [b] Fuel consumption includes acid gas 7,398 sm^3/hr and design fuel gas 3,065 sm^3/hr	

$$Mixed\ Gas\ CO_2\ Non\text{-}combusted\left(\frac{tonne}{y}\right) = Mixed\ Gas\ Flow\ Rate\left(\frac{m^3}{hr}\right) {*}24\left(\frac{hr}{d}\right) {*}365\left(\frac{d}{y}\right)$$
$$*\ CO_2\ Mole\ Fraction\ *\ Density\ of\ CO_2\left(\frac{1{,}861\ g}{m^3}\right)\ *\ Unit\ Conversion\left(\frac{1\ tonne}{10^6 g}\right)$$

$$Mixed\ Gas\ CO_2\ Emissions\ Combusted\left(\frac{tonnes}{y}\right) = \sum Mixed\ Gas\ Flow\ Rate\left(\frac{m^3}{hr}\right) {*}24\left(\frac{hr}{d}\right) {*}365\left(\frac{d}{y}\right)$$
$$*(Mole\ Fraction\ of\ Hydrocarbon\ Constituents)\ *\ (Number\ of\ Carbon\ Atoms\ in\ the\ Hydrocarbon\ Constituent)$$
$$Combustion\ Efficiency\left(\frac{99.9}{100}\right)\ *\ Density\ of\ CO_2\left(\frac{g}{m^3}\right)\ *\ Unit\ Conversion\left(\frac{1\ tonne}{10^6 g}\right)$$

$$CO_2\ Emissions\ Total\left(\frac{tonnes}{y}\right) = CO_2\ Emissions\ Non\text{-}combusted\left(\frac{tonnes}{y}\right) + CO_2\ Emissions\ Combusted\left(\frac{tonnes}{y}\right)$$

$$Mixed\ Gas\ CH_4\ Emissions\ Non\text{-}combusted\left(\frac{tonne}{y}\right) = Mixed\ Flow\ Rate\left(\frac{m^3}{hr}\right) {*}24\left(\frac{hr}{d}\right) {*}365\left(\frac{d}{y}\right)$$
$$*\ CH_4\ Mole\ Fraction\ *\ Density\ of\ CH_4\left(\frac{678 g}{m^3}\right)\ *\left(1\text{-}Combustion\ Efficiency\left(\frac{99.9}{100}\right)\right)$$
$$*\ Unit\ Conversion\ \left(\frac{1\ tonne}{10^6 g}\right)$$

$$Mixed\ Gas\ N_2O\ Emissions\left(\frac{tonnes}{y}\right) = Mixed\ Gas\ Flow\ Rate\left(\frac{m^3}{hr}\right) *24\left(\frac{hr}{d}\right) *365\left(\frac{d}{y}\right) * HHV\left(\frac{GJ}{m^3}\right) * Emission\ Factor\,(0.0000952\,\frac{kg}{GJ}) * \ Unit\ Conversion\,(\frac{1\ tonne}{10^6 g})$$

4.2.4 Flares

The Project is planning for three flares using a shared flared stack: a warm flare, a cold flare, and a low-pressure flare. Flaring is performed under the following scenarios:

- Normal operation flaring: Gas is assumed to be design fuel gas, see Table 4.7. Normal operating flaring emissions include pilot gas, purge gas, and captured seal gas venting emissions from the gas compressors.

  The following regulations are applied for compressor seal gas venting rate estimations:

  - According to *British Columbia Drilling and Production Regulation* (OGC 2010), centrifugal compressor vents should not exceed 0.057 sm^3 per minute.
  - According to *Regulations Respecting Reduction in the Release of Methane and Certain Volatile Organic Compounds* (Upstream Oil and Gas Sector) (Government of Canada 2018), reciprocating compressor vents should not exceed 0.001 sm^3 per minute per number of pressurized cylinders.

  It is assumed that venting rate will not exceed regulation limits. Therefore, seal gas venting rates are estimated using regulation limits for both centrifugal and reciprocating compressors. There are nine centrifugal compressors and two reciprocating compressors for the Project. It is assumed one reciprocating compressor has four cylinders.
- Maintenance flaring: Flaring related to maintenance is estimated to occur once a year for 24 hours for one train.

Flare operation information are listed in Table 4.13 as obtained from Cedar. The quantities of GHGs released are estimated following the WCI.363 equations 360-27 through 360-31 (WCI 2012). The pilot and purge flow rates for warm flare, cold flare, and low-pressure flare are 18.1 sm^3 per hour, 24.8 sm^3 per hour, and 22.3 sm^3 per hour, respectively. The compressor seal gas venting rate is 31.3 sm^3 per hour. The flare efficiency has been assumed to be 98% as per WCI (2011, 2013). The HHV for the N_2O calculation is assumed to be 51.38 MJ/m^3, which was calculated by Stantec based on the design fuel composition provided by Cedar. The densities of CO_2 and CH_4 are 1,861 g/sm^3 and 678 g/sm^3 and the N_2O emission factor is 9.52×10^{-5} kg/GJ as per WCI guidance (WCI 2011, 2013). Emissions are then calculated following the equations below.

Table 4.13 Flare Source Operation Information

Variable	Warm Flare	Cold Flare	Low-Pressure Flare
Operating hours [a]	8,760 hours per year	8,760 hours per year	8,760 hours per year
Fuel type [a]	Design Fuel Gas	Design Fuel Gas	Design Fuel Gas
Fuel consumption [a]	18.1 sm^3/hr (pilot + purge) + 31.3 sm^3/hr (vented compressor seal gas) [b]	24.8 sm^3/hr	22.3 sm^3/hr

NOTES:
[a] Provided by Cedar
[b] There are nine centrifugal compressors and two reciprocating compressors. Assumed that centrifugal compressor vent rate 0.057 sm^3/min (OGC 2010) and reciprocating compressor vent rate 0.001 sm^3/min/cylinder (Government of Canada 2018) and one compressor with four cylinders.

$$CO_2\ Emissions\ Non\text{-}combusted\left(\frac{tonne}{y}\right) = Pilot\ and\ Purge\ Rate\left(\frac{m^3}{hr}\right) *24\left(\frac{hr}{d}\right) *365\left(\frac{d}{y}\right)$$
$$*\ CO_2\ Mole\ Fraction\ *\ Density\ of\ CO_2\left(\frac{g}{m^3}\right)\ *\ Unit\ Conversion\left(\frac{1\ tonne}{10^6 g}\right)$$

$$CO_2\ Emissions\ Combusted\left(\frac{tonne}{y}\right) = \sum\ Pilot\ and\ Purge\ Rate\left(\frac{m^3}{hr}\right) *24\left(\frac{hr}{d}\right) *365\left(\frac{d}{y}\right)$$
$$*(Mole\ fraction\ of\ hydrocarbon\ constituents)\ *\ (Number\ of\ carbon\ atoms\ in\ the\ hydrocarbon\ constituent)$$
$$*\ Combustion\ Efficiency\left(\frac{98}{100}\right)\ *\ Density\ of\ CO_2\left(\frac{\mathrm{g}}{\mathrm{m}^3}\right) *\ Unit\ Conversion\left(\frac{1\ \mathrm{tonne}}{10^6\mathrm{g}}\right)$$

$$CO_2\ Emissions\ Total\left(\frac{tonnes}{y}\right) = CO_2\ Emissions\ Non\text{-}combusted\left(\frac{tonnes}{y}\right) + CO_2\ Emissions\ Combusted\left(\frac{tonnes}{y}\right)$$

$$CH_4\ Emissions\ Non\text{-}combusted\left(\frac{tonnes}{y}\right) = Pilot\ and\ Purge\ Rate\left(\frac{m^3}{hr}\right) *24\left(\frac{hr}{d}\right)$$
$$*\ 365\left(\frac{d}{y}\right) *\ (1\text{-}Combustion\ Efficiency\left(\frac{98}{100}\right))*\ \mathrm{CH_4\ Mole\ Fraction}$$
$$*\ Density\ of\ CH_4\left(\frac{g}{m^3}\right)\ *\ Unit\ Conversion\left(\frac{1\ tonne}{10^6 g}\right)$$

$$N_2O\ Emissions\left(\frac{tonnes}{y}\right) = Pilot\ Rate\left(\frac{m^3}{hr}\right) *24\left(\frac{hr}{d}\right) *365\left(\frac{d}{y}\right) *\ HHV\left(\frac{GJ}{m^3}\right)$$
$$*\ 0.0000952\left(\frac{kg}{GJ}\right) *\ Unit\ Conversion\left(\frac{1\ tonne}{10^3\ kg}\right)$$

To estimate maintenance flaring emissions, the assumption from the environmental assessment for LNG Canada (2014) was adopted. The 0.3% of the output mass of LNG produced is assumed to be equivalent to the mass of CO_2 discharged by flaring. The Cedar facility consists of two trains with an estimated design production of three million tonnes of LNG per year (MTPA). Assuming that one train is being maintained per year, total LNG production of that train is 1.5 MTPA. Applying the factor of 0.3% to the 1.5 MTPA value equates to 4,500 tonnes of CO_2.

4.2.5 Marine Operation

Marine operation includes emissions from marine vessels (i.e., LNG carriers and harbor tugboats) at the terminal (maneuvering and loading) and marine vessels (i.e., LNG carriers and escort tugboats) travelling along Douglas Channel between the Kitimat Harbour Terminal and the pilot boarding location near Triple Islands. The Project expects up to 50 carrier visits per year. During maneuvering and loading, it is assumed that two harbor tugboats will be required to support the operation. Stantec assumed that maneuvering time is 3 hours per visit and berthing, loading, and unberthing is 24 hours on average. During travel along the channel, it is assumed that two escort tugboats are available to support. Both LNG carriers and tugboats are assumed to run on marine diesel to be conservative (modern LNG carriers usually burn boil off gas, which is natural gas from the storage tanks). Marine vessel engine power, load factor, and operating hours are listed in Table 4.14 for terminal operation and Table 4.15 for channel travel. These values are confirmed by Cedar or assumed by Stantec.

Based on information from the American Petroleum Institute (2015), fugitive emissions during loading are minimal. Stantec has not quantified loading emissions.

The GHG emission factors (g/kWh) are based on engine type for LNG carriers and based on power rating for tugboats. The GHG emissions factors for CO_2, CH_4, and N_2O are shown in Table 4.14 and Table 4.15. The LNG carrier main engine is less efficient at low load and fuel consumption tends to increase. The low load adjustment factors (LLAF) were applied for adjusting propulsion engine combustion emission estimations. Emissions for the LNG carriers and the tugboats are calculated using the following equations listed below.

$$\begin{aligned}LNG\ Carrier\ Main\ Engine\ Emissions\left(\frac{tonnes}{y}\right) = {} & Emission\ Factor\left(\frac{g}{kW\text{-}hr}\right) * Engine\ Power\,(kW) * Load\ Factor\,\frac{(\%)}{100}\\ & * Low\ Load\ Adjustment\ Factor * Time\ Maneuvering/Loading/Travelling\left(\frac{hr}{visit}\right)\\ & * Vessel\ Number\left(\frac{visit}{y}\right) * Unit\ Conversion\left(\frac{1\ \text{tonne}}{10^6\text{g}}\right)\end{aligned}$$

$$\begin{aligned}LNG\ Carrier\ Auxiliary\ Engine/Boil\ and\ Tugboat\ Emissions\left(\frac{tonnes}{y}\right) = {} & Emission\ Factor\left(\frac{g}{kW\text{-}hr}\right) * Engine\ Power\,(kW)\\ & * Load\ Factor\,\frac{(\%)}{100} * Time\ Maneuvering/Loading/Travelling\left(\frac{hr}{visit}\right)\\ & * Vessel\ Number\left(\frac{visit}{y}\right) * Unit\ Conversion\left(\frac{1\ tonne}{10^6 g}\right)\end{aligned}$$

Table 4.14 Marine Vessel Information at Terminal

Variable	Units	LNG Carrier					Harbor Tugboats
		Main Engine	Auxiliary Engine		Boiler		
Activity	N/A	Maneuvering	Maneuvering	Loading	Maneuvering	Loading	Maneuvering/Loading
Engine power [a]	kW	31200	8020	8020	371	3000	1194
Load factor [b]	N/A	0.04 [c, d]	0.43	0.43	1.00	1.00	0.43
Berthing/unberthing [a]	hr	3	3	24	3	24	3
Vessels per year [a]	Number	50					2
Engine group	N/A	Propulsion	Auxiliary	Auxiliary	Boiler	Boiler	N/A
Emission Factors [b]							
CO_2	g/kWh	593.1	695.7	695.7	961.8	961.8	679.5
CH_4	g/kWh	0.012	0.008	0.008	0.002	0.002	0.00076
N_2O	g/kWh	0.029	0.029	0.029	0.075	0.075	0.033

NOTES:

[a] Confirmed by Cedar

[b] Based on U.S. EPA 2020

[c] Based on carrier maximum travel speed and average travel speed at terminal. The maximum travel speed is 23.7 knots (U.S. EPA 2020). Assumed average travel speed at terminal is 8 knots (ICF Consulting 2009).

[d] The low load adjustment factors are 2.01, 7.71, and 2.21 for CO_2, CH_4, and N_2O, respectively (U.S. EPA 2020)

N/A – not applicable

Table 4.15 Marine Vessel Information at Channel Travelling

Variable	Units	LNG Carrier					Escort Tugboats
		Main Engine	Auxiliary Engine		Boiler		
Activity	N/A	Maneuvering	Maneuvering	Loading	Maneuvering	Loading	Maneuvering
Engine power [a]	kW	31200	8020	N/A	371	N/A	1268
Load factor [b]	N/A	0.14 [c, d]	0.43	0.43	1.00	1.00	0.43
Shipping speed	knot	12.00	12.00	12.00	12.00	12.00	12.00
Shipping speed	km/h	22.20	22.20	22.20	22.20	22.20	22.20
Distance travelling along Douglas Channel	km	287.70	287.70	287.70	287.70	287.70	287.70
Shipping hours (one way)	hr	12.96	12.96	12.96	12.96	12.96	12.96
Vessels per year [a]	Number	50					2
Engine group	N/A	Propulsion	Auxiliary	Auxiliary	Boiler	Boiler	N/A
Emission Factors [b]							
CO_2	g/kWh	593.1	695.7	695.7	961.8	961.8	679.5
CH_4	g/kWh	0.012	0.008	0.008	0.002	0.002	0.00076
N_2O	g/kWh	0.029	0.029	0.029	0.075	0.075	0.033

NOTES:
[a] Confirmed by Cedar
[b] Based on U.S. EPA (2020)
[c] Based on carrier maximum travel speed and average travel speed at terminal. The maximum travel speed is 23.7 knots (U.S. EPA 2020). Assumed average travel speed along channel is 12 knots (LNG Canada 2014).
[d] The low load adjustment factors are 1.11, 1.47, and 1.08 for CO_2, CH_4, and N_2O, respectively (U.S. EPA 2020)
N/A – not applicable

4.2.6 Acquired Energy Emissions – Electricity Consumption

The electricity used during operation for the Project is supplied via a transmission line connected to the British Columbia electrical grid. During normal operation, the electricity demand is 164.9 megawatt. When loading LNG onto the LNG carriers, the electricity demand is slightly higher at 178.8 megawatt. The average electricity consumption is 1,461 gigawatt hour (GWh) per year.

The GHG emissions associated with this acquired energy were quantified by using the most recent electricity emission intensity factors recommended by the draft Technical Guide Related to the Strategic Assessment of Climate Change (ECCC 2021) (Table 4.16). The emission intensity factors include biomass and renewable natural gas. Indirect GHG emissions from acquired energy are calculated as per the equation below.

$$Emissions\ (t\ CO_2e/y\ ) = Electricity\ Consumption\ (GWh/y) * Emission\ Factor\ \left(\frac{tCO_2e}{GWh}\right))$$

Table 4.16 Electricity Emissions Intensity Factor

Year	Emissions Intensity ($t\ CO_2e/GWh$)
2027	13.6
2028	13.5
2029	13.4
2030	13.0
2031	12.6
2032	12.2
2033	12.2
2034	12.1
2035	12.0
2036	11.8
2037	12.0
2038	12.5
2039	14.5
2040	15.1
2041	16.2
2042	17.1
2043	17.2
2044	15.9
2045	15.3
2046	16.4
2047	17.7
2048	19.3
2049	20.2
2050	20.1
2051-2067	20.1
SOURCE: ECCC 2021	

5.0 RESULTS

5.1 CONSTRUCTION PHASE

The direct and indirect GHG emissions from the construction phase are presented in Table 5.1. The sources of direct GHG emissions include fuel combustion in on-road and off-road construction equipment, blasting activities, and land clearing, such as biomass burning and biomass decay. Construction emissions are mainly from land clearing activities (73%). The second largest source is off-road construction equipment (27%).

Table 5.1 Total Greenhouse Gas Emissions – Construction

Emission Source	Total Emissions (tonnes) [a] over Construction Period				Percent of Total Construction Emissions
	CO_2	CH_4	N_2O	CO_2e	
Direct Emissions					
Off-road construction equipment	9,458	0.328	1.04	9,775	27
On-road construction equipment	61.4	0.003	0.009	64.2	0.2
Blasting	82.9	N/A	N/A	82.9	0.2
Land clearing biomass burning (biomass-derived) [b]	N/A	N/A	N/A	16,169	44
Land clearing decay residuals (biomass-derived) [b]	N/A	N/A	N/A	10,560	29
Total Direct Emissions (including land clearing)	N/A	N/A	N/A	36,652	100
Total Direct Emissions (excluding land clearing) [b]	9,602	0.331	1.05	9,922	N/A
Total Direct Emissions per year of construction (including land clearing) [b]	N/A	N/A	N/A	9,163	N/A

NOTES:

[a] Totals may not sum due to rounding

[b] The CO_2 emissions associated with land clearing are from biomass. As per National Inventory Report (ECCC 2021), CO_2 derived from biomass is reported separately from CO_2 derived from fossil fuels. National totals exclude GHGs from the land use, land use change, and forestry sector.

N/A – not applicable

5.2 OPERATION PHASE

The emissions released during the operation phase include direct emissions from regeneration gas heater, auxiliary boiler, firewater pumps and generators, thermal oxidizer, flares, and marine emissions of vessels while in port and transiting. Indirect emissions from acquired energy were also included in the estimate of operation phase emissions. The quantities of estimated GHGs released during project operation from the various sources are summarized in Table 5.2.

Annual operation-related emissions (direct and indirect) amount to 240,449 tonnes of CO_2e per year (only including tugboat emissions). These estimates represent emissions of the operation activities required for the full build-out scenario (i.e., 3 MTPA of LNG production and 400 million standard cubic feet of feed gas per day). The emissions related to thermal oxidizer represent 70% of the annual operation GHG emissions, while the second largest emissions source is from the acquired energy (21%). Assuming the full build-out LNG production of 3 MTPA, the emission intensity of the project operation is 0.08 tonnes of CO_2e per tonne of LNG produced and 0.616 tonnes CO_2e per thousand cubic metres (m^3) of feed gas.

Table 5.2 Summary of Annual Operation GHG Emissions

Equipment	Emission Rate				
				Total	
	CO_2 (t/y)	CH_4 (t/y)	N_2O (t/y)	CO_2e (t/y)	Percent (%)
Heater/boiler/pumps/generators (direct emissions)					
Regeneration gas heater and auxiliary boiler	15,989	0.282	0.251	16,071	6.4
Two firewater pumps and four generators	154	0.008	0.023	161	0.1
Heater/boiler/pumps/generators total	**16,143**	**0.289**	**0.274**	**16,232**	**6.5**
Thermal oxidizer (direct emissions)					
Thermal oxidizer total	**191,985**	**14.7**	**0.133**	**192,393**	**76.6**
Flaring (direct emissions)					
Normal operation (3 flares) - total	2,333	9.13	0.004	2,563	1.0
Warm flare	1,195	4.68	0.002	1,312	0.5
Cold flare	600	2.35	0.001	659	0.3
Low-pressure flare	539	2.11	0.001	592	0.2
Maintenance flaring (startup/shutdown) [a]	4,500	N/A [a]	N/A [a]	4,500	1.8
Flares total	**6,833**	**9.13**	**0.004**	**7,063**	**2.8**

Table 5.2 Summary of Annual Operation GHG Emissions

Equipment	Emission Rate				
				Total	
	CO_2 (t/y)	CH_4 (t/y)	N_2O (t/y)	CO_2e (t/y)	Percent (%)
Marine emissions (direct emissions)					
LNG carriers – in port	6,991	0.06	0.422	7,118	2.8
Tugboats – in port	2.09	0.000002	0.0001	2.12	0.001
LNG carriers – in transit	3,686	0.07	0.173	3,740	1.5
Tugboats – in transit	9.60	0.00001	0.0005	9.74	0.004
Marine total	**10,689**	**0.130**	**0.596**	**10,860**	**4.3**
Acquired energy (indirect emissions)					
Acquired energy - total	N/A	N/A	N/A	**24,749**	**9.8**
Totals					
Total direct and indirect GHG emissions from operation (including all marine emissions)	**225,650**	**24.3**	**1.01**	**251,307**	100
Total direct and indirect GHG emissions from operation (only including tugboat emissions) [b]	**214,973**	**24.1**	**0.412**	**240,449**	95.7
Total direct GHG emissions from operation (only including tugboat emissions) [b]	**214,973**	**24.1**	**0.412**	**215,700**	85.8
Total direct GHG emissions from operation (including all marine emissions)	**225,650**	**24.3**	**1.01**	**226,558**	90.2
Emission intensity					
Emission intensity assuming 3 MTPA LNG production	**0.08** tonnes of CO_2e/tonne LNG				
	0.616 tonnes CO_2e per thousand m^3 of feed gas				

NOTES:

Totals might not add up due to rounding as presented numbers are rounded

N/A – not applicable

[a] Maintenance-related flare fuel volumes are unknown. Based on publicly available data, 0.3% of each train's output represents flared CO_2 emissions (LNG Canada 2014). CH_4 and N_2O emissions were assumed to be negligible.

[b] Only Canadian registered vessels are included in the total. LNG carriers are assumed international marine vessels and are hence excluded from the total. This follows the approach taken in the NIR (ECCC 2021).

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